Attachment B

D.20-01-002 Workshop Reports

GENERAL RATE CASE PLAN WORKSHOP #1 REPORT

Stipulated Terms, Rebuttable Presumptions, Standardized Attrition Year Ratemaking

October 5, 2020

1 Table of Contents

2 Executive Summary

On September 4, 2020, Energy Division hosted the first in a series of workshops to explore standardizing the organization and format of General Rate Case (GRC) and Risk Assessment Mitigation Phase (RAMP) filings for the large California energy utilities. The workshops were ordered in D.20-01-002, which modified the Commission's rate case plan for energy utilities. The objective of the workshops is to further explore and develop proposals to increase the efficiency of GRC proceedings. The scope of the first workshop was to establish the feasibility of the Commission adopting stipulated terms and/or rebuttable presumptions and whether attrition year ratemaking can be adopted under rebuttable presumptions.

In addition to CPUC staff, identified attendees at the workshop included Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), The Utility Reform Network (TURN), the Public Advocates Office, and Bear Valley Electric Service.

The workshop scope included two main subject areas:

1. Definitions of and proposals for standardizing stipulated terms and rebuttable presumptions
2. Proposals for standardizing attrition year mechanisms under rebuttable presumptions

On behalf of the joint investor-owned utilities (SCE, PG&E, SoCalGas, and SDG&E, collectively "IOUs"), SCE presented proposed definitions for stipulated terms and rebuttable presumptions. TURN presented a proposal for a rebuttable presumption for test year operations and maintenance (O&M) expense forecasts. On behalf of the IOUs, PG&E presented a proposal for rebuttable presumptions for standardizing attrition mechanisms. TURN then presented its proposal for rebuttable presumptions for standardizing attrition mechanisms.

There was discussion on each of the proposals, but no common agreements were reached, and no additional proposals incremental to what was presented by the IOUs and TURN were identified at the workshop.

TURN and the IOUs submitted post-workshop comments. TURN's comments noted areas of alignment and areas of disagreement between TURN's and the IOUs' proposals on the topic of Standardized Attrition Year Ratemaking. The IOUs' comments addressed TURN's Workshop 1 proposals and timing of the IOUs' recommendations on an appropriate vehicle or means to implement any agreed-upon efficiencies that result from all of the RCP workshops.

3 Introduction

On September 4, 2020, the California Public Utilities Commission's (CPUC) Energy Division hosted the first in a series of workshops to explore standardizing the organization and format of GRC and RAMP filings for the large California energy utilities. The workshops were ordered in D.20-01-002, which modified the Commission's rate case plan for energy utilities. The objective of the workshops is to further explore and develop proposals to increase the efficiency of GRC proceedings. The scope of the first workshop was to establish the feasibility of the Commission adopting stipulated terms and/or rebuttable presumptions and whether attrition year ratemaking can be adopted under rebuttable presumptions, such as using a predetermined escalation formula. The workshop was facilitated by Energy Division with support from SoCalGas/SDG&E.

4 Background

On January 16, 2020, the Commission issued Decision (D.)20-01-002 (the "Decision Modifying the Commission's Rate Case Plan for Energy Utilities" in Rulemaking (R.) 13-11-006, RCP Decision). D.20-01-002 adopted changes to the Rate Case Plan for large California energy utilities to enable the Commission to conduct GRC proceedings more efficiently, including modifications to the GRC procedural schedule and extending the GRC cycle for each utility from three years to four years. R.13-11-006 was closed upon CPUC adoption of D.20-01-002.

The RCP Decision also ordered a series of workshops to explore and develop proposals to increase the efficiency of GRC proceedings. CPUC staff identified four workshops and invited parties to provide feedback on the scope of each workshop:

1. Stipulated Terms / Rebuttable Presumptions / Standardized Attrition Year Ratemaking
2. Standardization of GRC Filings
3. Results of Operations (RO) Model Uniformity
4. Standardization of RAMP Filings

The large energy utilities: SoCalGas, SDG&E, PG&E, and SCE are supporting CPUC staff in facilitating the workshops, and a utility has been designated for each workshop. The RCP Decision also requires that no later than 30 days after the conclusion of the workshop, the designated utility shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies served on the service list of R.13-11-006 summarizing the workshop and any agreed-upon proposals.

5 Workshop

Energy Division held the first workshop virtually via a recorded WebEx session on September 4, 2020. Due to the state's public health order in response to the COVID-19 pandemic, there was no in-person attendance. Energy Division sent notice of the workshop to the service list for R.13-11-006. The public workshop notice was posted on the CPUC's Daily Calendar and website. The workshop, scheduled from 12:30 pm – 3:30 pm, included two main agenda topics:

1. Stipulated Terms and Rebuttable Presumptions
2. Standardized Attrition Year Ratemaking

Energy Division staff outlined the workshop objectives and logistics and requested meeting participants to identify their organization's attendance. In addition to CPUC staff, identified attendees at the workshop included SoCalGas, SDG&E, PG&E, SCE, TURN, the Public Advocates Office, and Bear Valley Electric Service.

6 Topic 1: Stipulated Terms and Rebuttable Presumptions

6.1 IOUs' Presentation on Stipulated Terms and Rebuttable Presumptions

On behalf of the IOUs, SCE presented proposed definitions for stipulated terms and rebuttable presumptions. For purposes of utility GRCs, the proposed definitions were:

Stipulated Term:

"Use or application of the Stipulated Term means that such use or application is deemed conclusively to be reasonable and not subject to re-litigation of the Stipulated Term. This definition will not apply if the party challenging the use or application of the Stipulated Term can show by admissible evidence that it is in fact not factually applicable at all, or can show by citation to binding precedent that use or application of the previously-established Stipulated Term is now contrary to law or binding regulatory precedent, so that current use of the Stipulated Term is prohibited."

A stipulated term is conclusive and not subject to re-litigation (other than the noted exceptions.) An example of a stipulated term is the use or application of Commission Standard Practices.

Rebuttable Presumption:

"If the rebuttable presumption is applicable, then the rebuttable presumption operates so that [rebuttable presumption] is assumed to be reasonable, and will be approved, adopted, or acknowledged by the Commission unless it is shown to be unreasonable through admissible evidence or through binding precedent from legislative, judicial, or regulatory authority."

An example of a rebuttable presumption is the use of Commission guidelines on forecasting methodology for test year O&M expense base forecasts. If the Commission's established methodology is used to forecast expense levels, then the forecasts are presumed to be reasonable. The presumption could still be challenged by another party who could provide evidence or citation to authority to overcome the presumption.

Adoption of such a rebuttable presumption would benefit all parties in GRC proceedings by potentially reducing the scope of litigation.

6.2 Discussion on the IOUs' Presentation

TURN generally agreed with the utilities' position that stipulated terms should be binding and difficult to overcome. TURN also agreed with the assertion that Commission forecasting standards have long been in place. Still, TURN noted that the primary disputes between parties in GRC proceedings continue to be related to forecasting methodologies. In TURN's opinion, overcoming a rebuttable presumption should require more than an "any evidence standard."

SCE clarified that it believed the utilities' definition of a rebuttable presumption would carry weight because, if the rebuttable presumption were applicable, the utility would be deemed to have met its burden of proof. SCE also indicated its belief that the example provided in the definition was meant to apply to O&M forecasts.

In response to Commission staff questions about where in GRC proceedings stipulated terms and rebuttable presumptions would apply, SCE noted that if Commission standard practices were applied as stipulated terms or rebuttable presumptions, then they could be applied consistently across utility rate cases. TURN offered as an example that the Commission could utilize a stipulated term to standardize which components of short-term incentive program (STIP) costs the utilities could seek recovery from ratepayers. SCE responded with reasons why it believed TURN's STIP example might not be applicable. TURN indicated that it had only provided an example for discussion purposes and the goal in defining rebuttable presumptions would be to reduce the amount of litigation. Both SCE and TURN noted that discussion had to be limited on this topic because it was a litigated item in SCE's open GRC proceeding. The same is true of at least one Commission Standard Practice, which prevented TURN from addressing the merits of SCE's suggestion that the use or application of Commission Standard Practices would count as a "stipulated term" under the IOUs' proposal.

6.3 TURN's Presentation on Stipulated Terms and Rebuttable Presumptions

TURN stated that its objectives for rebuttable presumptions were primarily to simplify rate case proceedings by reducing the need for extensive discovery and resource-intensive evaluation of routine matters and reducing the potential for asymmetry of information between the utilities and other participants. TURN expressed its belief that use of rebuttable presumptions would permit more time to focus on key policy issues, new programs, and emerging safety and reliability items.

TURN believes GRCs are so resource intensive because of the complexity of using a future test year to forecast GRCs coupled with the complexity of various forecasting methodologies employed to create test year forecasts. Strong rebuttable presumptions would reduce disputes over forecasting methodologies and reduce the need for discovery. CPUC forecasting standards (like those presented by SCE) should inform rebuttable presumptions, and rebuttable presumptions should be strong enough to deter parties from seeking to overcome them for each forecast.

TURN's proposed rebuttable presumption is:

"Base Year (or Last Recorded Year) plus inflation provides a reasonable forecast of Test Year O&M and A&G expense at a broad level with only a limited number of exceptions, subject to adjustments as warranted."

The foundation for TURN's rebuttable presumption assumes major areas of utility costs will, on average, increase at the rate of inflation and customer growth will be offset with productivity. TURN proposed parameters regarding the data and narrative utilities would be required to provide to support their forecasts and noted that parties would still have an opportunity to demonstrate that the rebuttable presumption is unreasonable in the context of specific forecasted expenses. TURN also proposed some possible exceptions where the rebuttable presumption would not apply and specific parameters for when adjustments to forecasts would be permitted. TURN concluded its presentation by suggesting requirements to overcome a rebuttable presumption.

For more detail on TURN's rebuttable presumptions proposal, please see Appendix A – section 9.3

6.4 Discussion on TURN's Presentation

SCE asked for clarifications on the factual basis for TURN's assumptions regarding its rebuttable presumptions and how TURN's proposal relates to the Commission's directive on forecast based ratemaking. TURN responded that it intended to offer a starting point for parties to discuss and explore potential alternatives for rebuttable presumptions. TURN offered that since the Commission has already provided guidance on when to employ forecasting methodologies, its proposed rebuttable presumption was intended to "tighten up" that guidance. SCE responded that it believed the Commission's guidance was appropriate for a base estimate which could then be incremented or decremented to derive a forecast. TURN concurred with SCE's interpretation of Commission guidance as applicable to base forecast and clarified that TURN's proposal addressed parameters around the adjustments to the base forecasts. TURN further offered that the intent of its proposed rebuttable presumption was to focus on the reasonableness of costs at the aggregate level as opposed to a line by line cost analysis.

SoCalGas/SDG&E asked whether TURN's rebuttable presumption assumed a specific inflation mechanism. TURN responded that a particular inflation mechanism was not proposed. SoCalGas/SDG&E also asked for clarification about the level of forecast where TURN's proposed exceptions would apply. SCE asked how TURN's proposal would impact the risk spending accountability reporting requirements given the macro level of forecasting employed in TURN's rebuttable presumption. TURN reiterated that its proposal was an opening position for further discussion and exploration and acknowledged that the issues raised during the workshop would need to be resolved.

Commission staff asked whether TURN's assertion that many GRC disputes are due to differences in forecasting methodology referenced differences between applicant's and intervenors' forecasts or differences between the utilities' forecasting methodologies for similar expense categories. TURN clarified it was a reference to the former. Commission staff also asked whether using "big data" or benchmarking that accounted for industry-wide cost trends has ever been contemplated to support cost forecasting in ratemaking proceedings (and clarified a SoCalGas/SDG&E question that this would be different than the total productivity factor study employed in past GRC proceedings). TURN mentioned awareness of consulting firms that perform cost benchmarking or cost data analysis, but no workshop participant identified significant past or contemplated efforts where big data has been leveraged on a wide scale for forecasting GRC costs. SCE mentioned that it uses IHS Markit data for cost inflation forecasting to normalize costs on a year-over-year basis.

6.5 Post-Workshop Comments on Stipulated Terms and Rebuttable Presumptions

The joint IOU comments are in Appendix B - at pp. 5-7.

7 Topic 2: Standardized Attrition Year Ratemaking

7.1 IOUs' Presentation on Standardized Attrition Year Ratemaking

On behalf of the IOUs, PG&E presented proposed rebuttable presumptions and supporting rationale for standardizing attrition year forecasts. The IOUs' proposals are based on recent rate case proceeding decisions, proposed settlement agreements and stipulations. PG&E stated that attrition mechanisms are intended to provide the utilities a reasonable opportunity to recover the cost of providing safe and reliable service and earn the authorized rate of return in between rate cases.

The proposed rebuttable presumptions are:

- *O&M and capital revenue requirements should have separate and distinct treatment.*
- *Revenue requirements for the attrition years should be implemented through an annual advice letter process.*
- *It is reasonable to authorize a z-factor mechanism for all years of a GRC cycle.*
- *Indices used to determine attrition year escalation should be reflective of the costs incurred by the utilities.*
- *It is reasonable to include in attrition calculations contractual labor rate changes known at the time of a utility's rate case Decision.*
- *Capital additions should be adopted as the capital adjustment in an attrition mechanism.*
- *Parties may propose reasonable adjustments to attrition mechanisms for specific programs that are not fully reflected in the test year.*

PG&E discussed the utilities' supporting rationale for each of the proposed rebuttable presumptions. For more detail on the IOU attrition standardization proposal, please see Appendix A – section 9.4.

7.2 Discussion on the IOUs' Presentation

TURN asked whether the utilities' proposed rebuttable presumption regarding the use of capital additions for the capital adjustments mechanism included specifics on what to use as the basis for capital additions (for example, test year authorized or utility budgets for attrition years). PG&E responded that the utilities do not have a specific proposal on what to use as the basis, but the intent of the rebuttable presumption is that the capital component of an attrition year be based on capital additions vs. other factors.

The Public Advocates Office commented that it generally sees four types of attrition mechanisms proposed in rate cases:

1. Percentage increase of the prior year's revenue requirement
2. Separate capital and O&M escalations
3. Special cases (*e.g.*, health benefits)
4. Budget-based capital proposals – which it believes the Commission has generally not adopted

PG&E indicated that the IOUs' proposal was a combination of Public Advocates Office items two and three. SCE responded that it has provided a budget-based forecast for capital for attrition years in its GRCs to provide visibility to the work that it plans to accomplish in the attrition period, but it has generally not been adopted. SoCalGas/SDG&E responded that they generally do not forecast specific capital additions in attrition years, but Pipeline Safety Enhancement Plan (PSEP) capital projects were an exception in the TY2019 GRC since the Commission ordered PSEP to be included. PG&E explained that it generally provides budgeted attrition year capital forecasts, but it does not base its attrition proposals on those forecasts.

Commission staff asked how capital projects subject to reasonableness review or that are forecasted to be in service in the attrition years of a GRC cycle (such as PSEP) would fit into a proposed attrition year mechanism. The utilities responded that this is generally what was contemplated by the proposed rebuttable presumption regarding reasonable adjustments to attrition mechanisms for specific programs that are not fully reflected in the test year. SoCalGas/SDG&E and TURN both added that PSEP was a considerable amount of work that could not be accounted for in other components of the attrition mechanism and therefore required a specific attrition adjustment mechanism.

7.3 TURN's Presentation on Standardized Attrition Year Ratemaking

TURN stated that it is more difficult to standardize attrition year rebuttable presumptions and there is less benefit from standardization, since there aren't many elements to attrition year proposals. TURN believes that attrition adjustments are intended to help offset inflationary pressures the utility will face, encourage the utility "to stretch to achieve productivity between test years" and "mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity." TURN also indicated that it believes attrition year adjustments are not intended to cover a utility's cost of service or guarantee a reasonable return during the attrition year, but they should provide a reasonable opportunity to earn a utility's authorized rate of return.

TURN believes the benefit of adopting rebuttable presumptions for a default attrition year mechanism is the potential to reduce litigation, but it would depend on the frequency that parties would seek to overcome the default rebuttable presumptions established for attrition mechanisms.

TURN's proposed rebuttable presumptions for attrition year adjustment mechanisms:

- *The Commission will presume that an attrition adjustment mechanism should be adopted in each GRC that escalates operating expenses by CPI-Urban.*
- *The Commission will presume that an attrition adjustment mechanism should be adopted in each GRC that calculates capital related costs based on historical capital trending. The historical capital trending should include a 7-year average of* <u>*recorded*</u> *capital additions, including the 5 years prior to the base year, the base year, and once available, the base year plus 1. Capital additions from each year should be expressed in constant (base year) dollars and may be normalized to the number of customers in each year before averaging.*

TURN believes that there are circumstances under which deviation from their proposed rebuttable presumption capital attrition adjustment mechanism would be warranted. TURN believes that to overcome its proposed rebuttable presumptions, it must be demonstrated that the capital attrition adjustment provided by the proposed mechanism will be grossly inadequate during the attrition years due to particular capital programs or major capital additions. TURN also stated that because of the uncertainty in forecasting attrition years due to the time lag, additional attrition increases over those provided by the default mechanism should be subject to a true-up. Finally, TURN proposes that any party should be able to provide evidence demonstrating that the default attrition adjustment assumes unreasonably high levels of capital additions in the attrition years.

For more detail on TURN's attrition standardization proposal, please see Appendix A – section 9.5.

7.4 Discussion on TURN's Presentation

A concern was once again raised regarding addressing items being litigated in open GRC proceedings, which limited the scope of the discussion. PG&E asked TURN to elaborate on the true-up in TURN's proposed attrition mechanism. TURN clarified that its proposed mechanism was intended to evolve through further discussion, but it foresees that a true-up for authorized adjustments outside the default mechanism could be handled through an annual advice letter process.

Commission staff asked for clarification on how TURN's proposal would change what is currently in place for attrition year mechanisms and what are the mechanisms currently used to determine escalation. TURN responded that its proposal has the potential for reducing litigation because it would raise the bar to overcome the default mechanism. TURN also opined that there is a lot of variation in parties' proposals and variation in what the Commission uses to determine attrition escalation for both O&M and capital.

The Public Advocates Office commented that it believes the utilities can propose whatever attrition year escalation mechanism they wish. Its concern with standardization under rebuttable presumptions is that there could be discontinuity between the escalation mechanism established through a rebuttable presumption and actual events. For example, some recent GRC proposals have included forecasted negative escalation between the test year and attrition year for certain components that might not align with the default mechanism defined in a rebuttable presumption.

7.5 Post-Workshop Comments on Standardized Attrition Year Ratemaking

TURN noted alignment between its proposed standardized approach and that of the IOUs on several issues: (1) separately adjusting O&M and capital revenue requirements; (2) implementing attrition rate adjustments through an annual advice letter process; (3) basing capital revenue requirement adjustments on capital additions; and (4) allowing for additional attrition year adjustments for specific programs under certain circumstances. Differences arise because of TURN's view of the purpose of attrition, which is not intended to cover the utility's cost of service, like a test year analysis, or all potential cost changes, but should encourage the utilities to stretch to achieve productivity. TURN accordingly disagrees with the IOUs' view that attrition year escalation should closely track the costs incurred by the utilities. Similarly, while TURN agrees that capital attrition should, as a general matter, be based on capital additions, TURN supports the use of recorded rather than forecast capital additions.

The joint IOU comments are in Appendix B - at pp. 8-10.

8 Next Steps

Commission staff explained that the workshop reports would reflect discussions and issues raised, and it will be reviewed with Energy Division management, ALJ Division management, and the assigned Commissioner's office (for R.13-11-006) to determine the appropriate next steps.

SoCalGas/SDG&E asked that if the outcome of the workshops would affect parties' rights or obligations in GRC proceedings, the Commission takes that into account when determining the next steps. SoCalGas/SDG&E also requested that if parties' proposals are to be considered further, there should be an opportunity to provide comments on proposals.

Commission staff requested that parties provide comments on proposals discussed in the workshop to be included in the report. Commission staff also noted the second RCP workshop will cover GRC standardization and is scheduled for October 7, 2020.

9 Appendix A – Workshop Presentations

9.1 Energy Division Workshop Introduction

9.2 IOU Presentation on Topic 2 Stipulated Terms and Rebuttable Presumptions (Slides 1-5)

9.3 TURN Presentation on Stipulated Terms and Rebuttable Presumptions (and Supplemental PDF)

9.4 IOU Presentation on Topic 4 Standardizing Attrition Ratemaking (Slides 6-13)

9.5 TURN Presentation on Standardizing Attrition Year Ratemaking

9.1 Energy Division Workshop Introduction

Rate Case Plan (Decision 20-01-002) Workshop #1
Stipulated Terms, Rebuttable Presumptions & Standardized Attrition Year Revenue Requirements

September 4, 2020

California Public Utilities Commission (CPUC)

CPUC Energy Division
Sempra Utilities Lead

Introductions

- CPUC – Energy Division
- Panelists/Presenters
- Organizations – via Chat function

Workshop Agenda

12:30pm – 12:40pm: **Introduction**

12:40pm – 1:45pm: **Stipulated Terms and Rebuttal Presumption**

1:45pm - 1:55pm: **Break**

1:55pm – 3:15pm: **Standardizing Attrition Mechanism**

3:15pm – 3:30pm: **Summary and Wrap up**

Workshop Purpose

- Meet requirements of RCP Decision 20-01-002
- Series of four workshops
- Scope of Workshop #1
- Work Product: Workshop Report

Workshop Goals

- A summary of the workshop discussion will be made available within 30 days following the workshop.
- The CPUC will review the information to determine an appropriate next step.

WebEx and Call-in Information

WebEx:

https://cpuc.webex.com/cpuc/onstage/g.php?MTID=ea4463b3761d63d3f392064a1453726a4

Recommend using audio through your computer if possible.

Call-in: +1-415-655-0002 (please note this number has tolls)

Meeting number (access code): 146 870 4115 Listen-only.

All participants in listen-only mode by default.

Please submit questions/comments via the WebEx chat and/or use the "raise hand" function.

Workshop Logistics

- Today’s Workshop Presentations are available in the meeting invite.
- Please identify yourself and your organization when speaking.
- This Workshop is being recorded.
- Host: Energy Division Staff - Carlos Velasquez and Jenny Au
- Lead: Sempra Utilities
- Panelists: Sempra, SCE, PG&E, and TURN
- Moderator: Evan Goldman

Summary & Wrap Up

Reminder:

All participants are in listen-only mode by default.

Please submit questions/comments via the WebEx chat and/or use the “raise hand” function.

9.2 IOU Presentation on Topic 2 Stipulated Terms and Rebuttable Presumptions (Slides 1-5)

RCP Workshop #1 – Agenda Topic 2 – Definitions of Stipulated Terms and Rebuttable Presumptions

Stipulated Term – Proposed Definition

For purposes of Utility General Rate Cases: "Use or application of the Stipulated Term means that such use or application is deemed conclusively to be reasonable and not subject to re-litigation of the Stipulated Term. This definition will not apply if the party challenging the use or application of the Stipulated Term can show by admissible evidence that it is in fact not factually applicable at all, or can show by citation to binding precedent that use or application of the previously-established Stipulated Term is now contrary to law or binding regulatory precedent, so that current use of the Stipulated Term is prohibited."

Stipulated Term – Example

Use or application of Commission Standard Practices.

Rebuttable Presumption - Proposed Definition

For purposes of Utility GRCs: “If the rebuttable presumption is applicable, then the rebuttable presumption operates so that [rebuttable presumption] is assumed to be reasonable, and will be approved, adopted, or acknowledged by the Commission unless it is shown to be unreasonable through admissible evidence or through binding precedent from legislative, judicial, or regulatory authority.”

Rebuttable Presumption - Example

The Commission has established guidelines for forecasting O&M expenses in General Rate Cases. These methodologies are commonly understood and have been used in an unbroken line of rate cases. The Commission-established guidelines for forecasting methodologies were articulated in D.89-12-057, and have been reinforced several times since then.[1] These guidelines explain when the Commission believes it is appropriate to use forecasting methodologies such as Last Recorded Year, Averaging, or Linear Trending.

While the Commission has indicated that these are not meant to be rigidly applied as "firm rules," these forecasting methodologies can be thought of as the equivalent of a presumption that can be rebutted. If an established methodology is used for the forecast, with no variance or additional incremental request, then a rebuttable presumption of reasonableness would apply to the forecast. This will aid judicial economy and efficiency, lower the burden of litigation on the Commission, the GRC Parties, Energy Division Staff, and other stakeholders, and prevent "re-litigation" in an individual utility's rate case of these Commission-established and generally applicable methodologies.

1 See, e.g., D.04-07-022, pp. 15-16; D.06-05-016, pp. 10-11.

9.3 TURN Presentation on Stipulated Terms and Rebuttable Presumptions (and Supplemental PDF)

Using Rebuttable Presumptions In Test Year Forecasting to Reduce Complexity in GRCs

THE UTILITY REFORM NETWORK

Lower bills. Livable planet.

Rate Case Plan Workshop #1

September 4, 2020

TURN Goals for Rebuttable Presumptions

1. To simplify the rate case and reduce the need for resource-intensive evaluation on routine matters;
2. To reduce disputes around the accuracy of forecasting;
3. To make the rate case more transparent for evaluators;
4. To reduce the potential for gaming and asymmetry of information that benefits utilities;
5. To make it easier to process a case on time, while still providing more time for examining key policy issues such as safety and reliability; and
6. To provide clarity on the meaning of the utility's burden of proof as to the reasonableness of its forecast and past expenditures.

GRCs are extremely resource-intensive

- California's use of a future test year, coupled with the particulars of utility forecasting methodologies, drive this complexity.

- Utility forecasts tend to be granular, data-intensive, and incredibly resource-intensive to evaluate, in part because of the extreme asymmetry of information between the utility, intervenors, and the Commission.

- TURN routinely devotes 3,500 to 6,500 hours to each GRC and sends between 800 and 1,000 data request questions.

Benefits of Using Test Year Forecast Rebuttable Presumptions

- Many GRC disputes boil down to a difference in forecasting methodology.

- Rebuttable presumptions would reduce the need for discovery, minimize disputes around the accuracy of forecasting, and enable a more focused review of new programs and key policy issues such as safety and reliability.

The CPUC's forecasting guidance should inform rebuttable presumptions

Per D.04-07-022 (at pp. 15-17):

- "If recorded expenses in an account have been **relatively stable** for three or more years" ➔ use ***Last Recorded Year*** as base estimate
- "If recorded expenses in an account have shown **a trend** in a certain direction over three or more years, the [last recorded year] level is the most recent point in the trend" ➔ use ***Last Recorded Year*** as base estimate
- "For those accounts which have **significant fluctuations** in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility" ➔ use ***Historical Average*** as base estimate
- ***Budget-Based*** forecasts are **disfavored**: "[B]ecause utility spending plans may not always be implemented as intended, budget-based forecasts generally will be given less weight than forecasts based on recorded spending in the absence of a showing supporting the contrary approach."

TURN's Proposed Rebuttable Presumption

Base Year (or Last Recorded Year) plus inflation provides a reasonable forecast of Test Year O&M and A&G expense at a broad level with only a limited number of exceptions, subject to adjustments as warranted.

The following slides cover:

1. Basic Information
2. Exceptions and Special Calculations
3. Adjustments
4. Showing to Overcome the Rebuttable Presumption

TURN's Proposed Rebuttable Presumption – Basic Information

- Assumption: Some individual routine costs may increase at a rate higher than inflation, while others may increase at a lower rate, but in total the average increase should be something akin to an inflation adjustment applied at a very high level of utility operations, such as electric distribution, gas distribution, electric generation, A&G, etc.
- Assumption: Increases in costs due to customer growth will be offset with productivity under the rebuttable presumption. The "inflation adjustment" should reflect a reasonable level of productivity.
- The utility would continue to provide five years of recorded data at the account level. If the base year varies by the larger of 5% or $100,000 relative to the previous year in real terms, a brief narrative explanation would be provided unless the account falls into one of the exceptions to the rebuttable presumption (in which case the account would be separately forecast).
- The utility and intervenors would have an opportunity to demonstrate that the rebuttable presumption is unreasonable in the context of specific O&M or A&G expenses.

TURN's Proposed Rebuttable Presumption – Exceptions

1. New or expanding programs put in place for safety, reliability, and public policy reasons
2. Costs that should be averaged because they tend to fluctuate (storms, claims, workers' compensation, employee relocation/severance, etc.)
3. Costs that are reasonable to forecast as a percentage of revenue or percentage of other costs (where historical data shows a strong correlation)
   - For items that are a percentage of revenue (franchise fees, etc.) the costs should be averaged as a percent of revenue, rather than as a dollar amount
   - For items affected by the number of employees or labor expenses (benefits, payroll taxes), calculate base year costs on a per-employee or a per-labor dollar basis
4. Certain generation-related costs requiring special accounting (nuclear refueling outage expenses, Long Term Service Agreements for combined cycle plants, generation costs that vary with hours run or kW hours produced)
5. Other operating revenues may require special accounting if driven by number of customers rather than inflation or to capture changes in tariffed charges after the base year.

TURN's Proposed Rebuttable Presumption – Adjustments

1. For "known and measurable" changes in the test year *of more than $1 million* for PG&E, SCE, and SoCalGas and *more than $500,000* for SDG&E -- smaller O&M adjustments are only permitted if related to specific governmental requirements
2. For one-time O&M costs in the base year or test year, but only where there is a significant increase in one-time costs across the utility in aggregate in the base year relative to earlier years or in the test year relative to the base year
3. For capital projects in the test period that reduce O&M expenses – to normalize expense reduction into the test year

Showing to Overcome TURN's Rebuttable Presumption

- General: Any adjustment of any kind that spans more than one account would be identified and discussed in a single place in testimony and the effect of that adjustment on all accounts would be identified in one place, with cross-references to all affected accounts.

- Specific Showings:
  - Known and Measurable Changes – evidence demonstrating that such changes will affect the test year relative to the base year significantly more or less than the rebuttable presumption captures
  - One-Time Costs – evidence demonstrating that base year utility-wide one-time costs are not illustrative of test year one-time costs

Showing to Overcome TURN's Rebuttable Presumption

- Specific Showings: (continued)
  - Customer Growth – evidence establishing that costs cannot be offset by productivity
  - Unit Costs– evidence demonstrating reasonableness of non-standard escalation
  - Vacant Positions – evidence establishing that vacancies utility-wide were unusual in the base year
  - Employee Benefit Programs –evidence of changes in benefits

(more detail in the PDF attachment to TURN's presentation)

TURN Presentation #1

Using Rebuttable Presumptions In Test Year Forecasting to Reduce Complexity in GRCs

I. TURN Goals for Rebuttable Presumptions

- To simplify the rate case and reduce the need for resource-intensive evaluation on routine matters;
- To reduce disputes around the accuracy of forecasting;
- To make the rate case more transparent for evaluators;
- To reduce the potential for gaming and asymmetry of information that benefits utilities;
- To make it easier to process a case on time, while still providing more time for examining key policy issues such as safety and reliability; and
- To provide clarity on the meaning of the utility's burden of proof as to the reasonableness of its forecast and past expenditures.

II. GRCs are extremely resource-intensive

- California's use of a future test year, coupled with the particulars of utility forecasting methodologies, drive this complexity.

- Utility forecasts tend to be granular, data-intensive, and incredibly resource-intensive to evaluate, in part because of the extreme asymmetry of information between the utility, intervenors, and the Commission.

- TURN routinely devotes 3,500 – 6,500 hours to GRCs

    - Variation associated with whether a case is fully litigated or settled, and whether TURN shares issues with UCAN (common in Sempra GRCs)

        - PG&E TY 2020 GRC – 3,600 hours *to-date* (settled before briefs)
        - Sempra TY 2019 GRC – 3,400 hours (litigated, UCAN issue split)
        - SCE TY 2018 GRC – 6,400 hours (litigated)
        - PG&E TY 2017 GRC – 4,800 hours (settled)
        - SCE TY 2015 GRC – 5,300 hours (litigated)
        - PG&E TY 2014 GRC – 5,700 hours (litigated)

- Data Requests propounded by TURN in recent GRCs:

    - SCE TY 2021 GRC (Track 1): 117 data requests with 983 questions
    - PG&E TY 2020 GRC: 103 data requests with 831 questions
    - Sempra TY 2019 GRC (case coverage shared with UCAN): 85 data

requests with 806 questions

III. Benefits of Using Test Year Forecast Rebuttable Presumptions

- Many GRC disputes boil down to a difference in forecasting methodology.

- Rebuttable presumptions would reduce the need for discovery, minimize disputes around the accuracy of forecasting, and enable a more focused review of new programs and key policy issues such as safety and reliability.

IV. The Commission's long-standing forecasting guidance should inform rebuttable presumptions.

- D.04-07-022 (at pp. 15-17) summarizes the four most common methods for forecasting test year costs -- Last Recorded Year, Historical Average, Linear Trending, and Budget-Based – and provides guidance on when to use each.

    - "If recorded expenses in an account have been relatively stable for three or more years" ➔ use ***Last Recorded Year*** as base estimate

    - "If recorded expenses in an account have shown a trend in a certain direction over three or more years, the [last recorded year] level is the most recent point in the trend" ➔ use ***Last Recorded Year*** as base estimate

    - "For those accounts which have significant fluctuations in recorded expenses from year to year, or which are influenced by weather or other external forces beyond the control of the utility" ➔ use ***Historical Average*** as base estimate

    - ***Budget-Based*** forecasts are disfavored: "[B]ecause utility spending plans may not always be implemented as intended, budget-based forecasts generally will be given less weight than forecasts based on recorded spending in the absence of a showing supporting the contrary approach."

V. TURN's Proposed Rebuttable Presumption

Base Year (or Last Recorded Year) plus inflation provides a reasonable forecast of Test Year O&M and A&G expenses at a broad level with only a limited number of exceptions, subject to adjustments.

1. Basic Information

- The rebuttable presumption assumes that some individual routine costs may increase at a rate higher than inflation, while others may increase at a lower rate, but in total the average increase should be something akin to an inflation adjustment applied at a very high level of utility operations, such as electric distribution, gas distribution, electric generation, A&G, etc.

- The rebuttable presumption assumes that increases in costs due to customer growth will be offset with productivity under the rebuttable presumption. The "inflation adjustment" should reflect a reasonable level of productivity.

- The utility would continue to provide five years of recorded data at the account level. If the base year varies by the larger of 5% or $100,000 relative to the previous year in real terms, a brief narrative explanation would be provided unless the account falls into one of the exceptions to the rebuttable presumption (in which case the account would be separately forecast).

- The utility and intervenors would have an opportunity to demonstrate that the rebuttable presumption is unreasonable in the context of specific O&M or A&G expenses.

2. Exceptions to the rebuttable presumption that should be separately forecast

- New or expanding programs put in place for safety, reliability, and public policy reasons

- Costs that should be averaged because they tend to fluctuate (storms, claims, workers' compensation, employee relocation / severance, etc.)

- Costs that are reasonable to forecast as a percentage of revenue or other costs (where historical data shows a strong correlation)

    - For items that are a percentage of revenue (franchise fees, etc.) the costs should be averaged as a percent of revenue, rather than as a dollar amount.
    - For items that are affected by the number of employees or labor expenses (benefits, payroll taxes), the utility should calculate base year costs on a per-employee or a per-labor dollar basis.

- Certain generation-related costs requiring special accounting

    - Nuclear refueling outage expenses calculated on a per-outage basis and allowed for the utility based on actual number of outages.
    - Long Term Service Agreements for combined cycle plants – the future expected costs should be averaged over the rate case cycle.
    - Some generation costs (e.g., consumables, water) may also vary with hours run or kilowatt-hours produced and would therefore require special calculations.

- Other operating revenues may require special accounting if driven by number of customers rather than inflation or to capture changes in tariffed charges after the base year.

3. Adjustments to the forecast resulting from the rebuttable presumption

- For "known and measurable" changes in the test year *of more than $1 million* for PG&E, SCE, and SoCalGas and *more than $500,000* for SDG&E
  - Smaller O&M adjustments are only permitted if related to specific governmental requirements

- For one-time O&M costs in the base year or test year, but only where there is a significant increase in one-time costs across the utility as a whole in the base year relative to earlier years or in the test year relative to the base year

- For capital projects in the test period that reduce O&M expenses – to normalize expense reduction into the test year

4. Showing to overcome the rebuttable presumption

- **General:** Any adjustment of any kind that spans more than one account would be identified and discussed in a single place in testimony and the effect of that adjustment on all accounts would be identified in one place, with cross-references to all affected accounts.

- **Known and Measurable Changes:** Evidence of known and measurable changes that will affect the test year costs relative to the base year (either higher or lower than the rebuttable presumption) should be provided. No single O&M adjustment will be under $1 million, in the case of PG&E SCE, and SoCalGas, or $500,000, for SDG&E, unless based on specific changes in government actions. A programmatic adjustment spanning several accounts may be counted as one adjustment for this purpose.

- **One-time costs:** The rebuttable presumption assumes that aggregate one-time costs in the base year are comparable to one-time costs in the test year. To add one-time costs in the test year, an analysis must be provided that demonstrates that the aggregate of one-time costs in the test year is reasonably expected to exceed the aggregate of one-time costs recorded in the base year. If approved, any excess one-time costs in the future test year above base year levels should be averaged over the rate case cycle (i.e., one-fourth allowed if one-time for a single year in a 4-year cycle). One-time costs should be removed from the base year only if there is a significant increase in one-time costs across the utility as a whole in the base year relative to earlier years. To facilitate consideration of whether adjustments to the rebuttable presumption for one-time costs are appropriate, the utility should identify one-time costs in the base year and previous four years for each account.

- **Customer Growth:** Customer growth adjustments to O&M expenses between base year and test year are specifically included in the rebuttable presumption. The utility has the burden of proof to establish that increased costs due to customer growth cannot be offset by productivity between the base year and test year.

- **Unit Costs:** Increases above inflation for unit costs of certain items included in non-labor inflation shall fall under the rebuttable presumption. For those items, it shall be assumed that non-labor inflation rates encompass all inflation on a company-wide basis unless shown otherwise. If the utility wishes to request an increase greater than inflation for an item, it should include the item's costs under non-standard escalation, and provide information (a) proving that its request is reasonable and (b) proving that the specific item is not included in the calculation of non-labor inflation for the cost type in question.

- **Vacant Positions:** Adjustments to refill vacant positions or annualize costs of vacant positions filled during the base year are specifically included in the rebuttable presumption, because vacancies in the base year in the aggregate are presumed to be equal to vacancies in the test year on a corporate-wide basis unless proven otherwise. Any such adjustments must be accompanied by an analysis of the company's level of unfilled positions over the base year and four preceding years on a company-wide basis to show that vacancy levels were unusual in the base year. Any such adjustments must also net out corresponding reductions to overtime that would result from filling vacant positions.

- **Employee Benefit Programs:** Adjustments for changes in employee benefit programs that are expected to occur must be justified with supporting evidence.

9.4 IOU Presentation on Topic 4 Standardizing Attrition Ratemaking (Slides 6-13)

RCP Workshop #1 – Agenda Topic 4 – Standardizing Attrition Mechanisms

Standardizing Attrition Mechanisms - 1

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
O&M and capital revenue requirements should have separate and distinct treatment.	• O&M expenses and capital expenditures affect revenue requirement differently. • A single escalation factor does not appropriately reflect cost of service.

Standardizing Attrition Mechanisms - 2

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
Revenue requirements for the attrition years should be implemented through an annual advice letter process.	• Each IOU may have slightly different processes, but share a goal of having authorized rates in place effective January 1st of the applicable year. • This results in more stable customer bills by consolidating revenue changes.

Standardizing Attrition Mechanisms - 3

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
It is reasonable to authorize a z-factor. mechanism for all years of a GRC cycle.	• A Z-Factor event is unpredictable and occurs after base rates have been set. • A Z-Factor event is as likely to occur in the test year as in the attrition years. • In previous rate case decisions this has been established for certain utilities.

Standardizing Attrition Mechanisms - 4

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
Indices used to determine attrition year escalation should be reflective of the costs incurred by the utilities.	• Both utilities and ratepayer advocates should have a common interest in ensuring that the indices are accurate. In that way, a clear apples-to-apples comparison can be drawn from year-to-year regarding the rise in real costs exclusive of inflation. • Indices specific to the utility industry more accurately reflects utility inflationary costs. • Broad indices that reflect inflationary pressures for goods and services in general do not accurately reflect the specific basket of goods and services that the utility employs on behalf of its customers. • For medical cost escalation, it is appropriate to use an estimating methodology reflective of medical cost trends and the Utility's medical provider marketplace and plans.

Standardizing Attrition Mechanisms - 5

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
It is reasonable to include in attrition calculations contractual labor rate changes known at the time of a utility's rate case Decision.	• Given its potential for uncertainty, it is reasonable to update for this cost element.

Standardizing Attrition Mechanisms - 6

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
Capital additions should be adopted as the capital adjustment in an attrition mechanism.	• Capital additions are representative of the capital-related revenue requirement utilities require in attrition years.

Standardizing Attrition Mechanisms - 7

Utilities' Proposed Rebuttable Presumption	Principle / Supporting Rationale
Parties may propose reasonable adjustments to attrition mechanisms for specific programs that are not fully reflected in the test year.	• Large programs/projects may have one-time events or lumpy spending patterns. • Because the Commission has adopted a four-year GRC cycle, the utility is projecting from two to six years ahead when it develops its forecasts for its application. • The further out one goes, the greater the chances that re-prioritization, new or changing system needs, technological developments, and other emergent factors may cause the utility's actual spend to differ from what was forecast or what was authorized. Utility leadership must have some degree of flexibility to meet these changed circumstances.

9.5 TURN Presentation on Standardizing Attrition Year Ratemaking

Standardizing Attrition Year Revenue Requirement Adjustments

Rate Case Plan Workshop #1
September 4, 2020

The Purpose of Attrition Year Adjustments

Attrition year adjustments **are**:

- Intended to help offset inflationary pressures the utility will face
- Intended to encourage the utility "to stretch to achieve productivity between test years"
- Intended to "mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity"

Attrition year adjustments **are not**:

- An “entitlement” for utilities
- Intended “to insulate the company from the economic pressures which all businesses experience”
- Intended to cover the utility’s cost of service, like a test year analysis, or “all potential cost changes”
- Intended “to guarantee the utility’s rate of return during the attrition years”

(Source: D.20-01-002, D.19-05-020, D.17-05-013, and D.14-08-032)

Benefits of Adopting a Default Attrition Year Adjustment Mechanism

- Attrition year adjustments are highly contested in GRCs
- Disputes are generally around the mechanism used to calculate adjustments
- Adopting a default adjustment mechanism could reduce litigation

TURN's Proposed Default Attrition Year Adjustment Mechanism

- The Commission will presume that an attrition adjustment mechanism should be adopted in each GRC that escalates operating expenses by CPI-Urban.
- The Commission will presume that an attrition adjustment mechanism should be adopted in each GRC that calculates capital related costs based on historical capital trending. The historical capital trending should include a 7-year average of recorded capital additions, including the 5 years prior to the base year, the base year, and once available, the base year plus 1. Capital additions from each year should be expressed in constant (base year) dollars and may be normalized to the number of customers in each year before averaging.

Showing Required to Demonstrate that the Default Attrition Adjustment is Unreasonable

- To overcome this presumption of reasonableness, a utility seeking a larger attrition adjustment must demonstrate that because of particular capital programs, or a major capital addition, the capital attrition adjustment provided by this mechanism will be grossly inadequate during the attrition years.

- Unless the attrition year capital budgets for identified programs are mandated by law or regulation, additional attrition increases, if justified, will be authorized subject to true-up, given the uncertainties surrounding budget-based capital forecasting.

Showing Required to Demonstrate that the Default Attrition Adjustment is Unreasonable

(continued)

- Any party can provide evidence demonstrating that the default attrition adjustment assumes unreasonably high levels of capital additions in the attrition years.

10 Appendix B – Post-Workshop Comments on the Workshop

Joint IOU Comments to Rate Case Plan Workshop #1

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities	Rulemaking 13-11-006 (Filed November 14, 2013)

JOINT COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND PACIFIC GAS AND ELECTRIC COMPANY (U 39-M) TO RATE CASE PLAN WORKSHOP NUMBER 1

Sharon L. Cohen
Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (619) 696-4355
Facsimile: (619) 699-5027
E-mail: slcohen@sdge.com

September 29, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities	Rulemaking 13-11-006 (Filed November 14, 2013)

JOINT COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND PACIFIC GAS AND ELECTRIC COMPANY (U 39-M) TO RATE CASE PLAN WORKSHOP NUMBER 1

I. INTRODUCTION

In accordance with guidance provided by the Staff of the California Public Utilities Commission ("Commission"), the Investor Owned Utilities ("IOUs") Southern California Gas Company ("SoCalGas"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE") and Pacific Gas and Electric Company ("PG&E") (collectively, the "Joint IOUs") respectfully submit their joint comments regarding the September 4, 2020, workshop ("Workshop 1"). Workshop 1 was conducted pursuant to the Commission's recent decision ("D") in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision").

II. BACKGROUND

A. Purpose and Scope of RCP Workshops

The RCP Decision was issued to address the Commission's preference for greater efficiencies in processing the large energy utilities' general rate case ("GRC") proceedings, and to "ensure that complex and financially significant GRC proceedings follow a predictable schedule that balances the need for timely Commission decisions with procedural fairness for all parties."[1] The RCP Decision did not reach a determination on all issues raised by parties to the Rulemaking. Instead, the Commission ordered additional workshops to be facilitated by the Commission's Energy Division (in consultation with the Safety and Enforcement Division as appropriate) "to further explore and develop proposals to increase the efficiency of GRC proceedings"[2] on four topics:

- Standardizing the organization and format of GRC and Risk Assessment and Mitigation Plan ("RAMP") filings;
- The possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking;
- High-level consistency in the Results of Operations modeling process across utilities; and
- The timing and implementation of Phase 2 applications on electric and gas rate design and cost allocation.[3]

Upon the conclusion of the workshop or workshops, "a designated utility shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies to this proceeding's service list summarizing the workshop or workshops and any agreed-upon proposals, as a compliance item in this docket."[4]

Perhaps anticipating that the workshops would develop additional "actionable" recommendations to improve the GRC process, the Commission closed the RCP Rulemaking,

---

[1] D.20-01-002 at 2.

[2] *Id.* at 3-4. *See also id.at 79,* Ordering Paragraph (OP) 5.

[3] *Id.* at 3-4 and 76 (Finding of Fact (FOF) 8) ("Additional workshops could explore standardizing the organization and format of GRC and RAMP filings; the possible use of stipulated terms and rebuttable presumptions to reduce litigated issues, and improving the accuracy of attrition year forecasting, escalation factors, and ratemaking.......").

[4] *Id.* at 79, OP 5.

and preserved its options for acting upon those later recommendations.[5] In the interests of judicial economy and efficiency, and after careful consideration, the IOUs propose to participate in and obtain guidance and feedback from the entire series of workshops before proposing their recommendations on an appropriate vehicle or means for the Commission and parties to implement any agreed-upon efficiencies that result from the workshops. The Joint IOUs believe that our recommendations will be more meaningful to parties and useful to the Commission if the recommendations are informed by a holistic perspective that takes into account the entire spectrum of thought collaboration and robust debate that has occurred during the workshops.

The Joint IOUs remain hopeful that substantive gains can be made by parties finding common ground and consensus on items. However, at the Workshop, even IOU proposals that followed long-established Commission guidance found no real traction. And, proposals made by The Utility Reform Network ("TURN")[6] recast litigation positions in a manner that, if granted by the Commission, would be severely detrimental to the IOUs, their customers, and the communities they serve by making it more difficult to obtain a revenue requirement sufficient to provide safe and reliable service. While no consensus was achieved after multiple hours of discussion at Workshop 1, the Joint IOUs will continue to actively participate in the remaining workshops in an effort to find uniform efficiencies across all GRCs through this process.

B. Comments on Workshop 1: Stipulated Facts, Rebuttable Presumptions, and Attrition Year Improvements

As the Commission noted in the most recent Rate Case Plan Decision, the purpose of the GRCs is for the Commission "to authorize the level of funding necessary for the applicant utility

[5] *See* D.20-01-002 at 74.

[6] The Joint IOUs and TURN were the only Workshop 1 participants who provided proposals.

to provide safe and reliable service at just and reasonable rates."[7] The Joint IOUs agree with TURN that the examination required for the Commission to approve GRCs is substantial. We share TURN's stated interest in making the proceedings more efficient, which was the Commission's intent in requiring the four additional workshops.[8]

The first GRC workshop held on September 4, 2020, addressed issues that are fundamental to the determination of the amount of revenue requirement that should be authorized to the IOUs to provide safe and reliable services. As these issues are typically contested in the IOUs' pending GRCs, it is perhaps unsurprising that the workshop participants were unable to reach an agreement on these issues. While no agreements were reached in the first workshop, as indicated above, the Joint IOUs look forward to participating in additional workshops on the Rate Case Plan and hope that common ground can be established on other issues to meet the Commission and parties' objective to increase the efficiency of the GRC proceedings.

Below, the Joint IOUs respond briefly to TURN's proposals in the first workshop, consistent with instructions in the Draft Report.[9]

---

[7] D.20-01-002 at 60.

[8] D.20-01-002 at 2.

[9] Draft Report, Section 8, *Next Steps.* The Comment date was moved to September 29, 2020 by e-mail to the service list on September 17, 2020.

Topic 1: Stipulated Terms[10] and Rebuttable Presumptions

The Joint IOUs agree with TURN that the Commission guidelines for forecasting methodologies initially articulated in D.89-12-057 and reinforced several times,[11] should create a presumption that the applicable forecasting methodology used for a base estimate is reasonable.[12] As the Joint IOUs noted during Workshop 1, while the Commission has indicated that the forecasting methodologies should not be rigidly applied as "firm rules," these forecasting methodologies can be thought of as the equivalent of a presumption that can be rebutted. If an established methodology is used for the forecast, with no variance or additional incremental request, then a rebuttable presumption of reasonableness should apply to the forecast.[13] This was proposed to aid efficiency and reduce the burdens of litigation. In other words, the rebuttable presumption should lower or eliminate the burden of "re-litigating" these items in each individual utility's rate case even when Commission-recommended guidance is being linearly followed.

Although claiming that "[t]he CPUC's forecasting guidance should inform rebuttable presumptions,"[14] TURN's proposal substantially diverges from Commission guidance. TURN proposes as a rebuttable presumption for the test year that "[b]ase Year (or Last Recorded Year) plus inflation provides a reasonable forecast of Test Year O&M and A&G expense at a broad

---

[10] Only the Joint IOUs provided a proposal for "Stipulated Terms." *See* Draft Report, Appendix A, Chapter 9.2, IOU Presentation on Definitions of Stipulated Terms and Rebuttable Presumptions ("IOU Presentation"), Slides 2-3. During discussion, "TURN generally agreed with the utilities' position that stipulated terms should be binding and difficult to overcome." Draft Report at 5.

[11] *See, e.g.*, D.04-07-022 at 15-16; D.06-05-016 at 10-11.

[12] *See*, Appendix A, Chapter 9.3, TURN, Using Rebuttable Presumptions in Test Year Forecasting to Reduce Complexity in GRCs ("TURN Rebuttable Presumption Presentation") at Slide 5.

[13] *See* Draft Report, Appendix A, Chapter 9.2, IOU Presentation at Slide 5.

[14] *See* TURN Rebuttable Presumption Presentation at Slide 5.

level with only a limited number of exceptions, subject to adjustments as warranted."[15] The "inflation" adjustment is further derived by a proxy that assumes that increased costs due to customer growth is offset by productivity.[16]

The Joint IOUs cannot support TURN's proposal. Under TURN's proposal, for all practical purposes, the IOUs would not be permitted to propose a forecast in many areas of the case necessary for safe and reliable service to customers. It would limit the IOUs' ability to obtain an appropriate revenue requirement for a program if the funding that is needed exceeds the amount of the base cost estimate, as adjusted by TURN's proposed proxy for inflation with limited exception.[17]

As discussed further below, since the IOUs' needs for work, risks, and priorities evolve over time, the Joint IOUs cannot agree to TURN's proposals for additional rules and limitations that would erase the IOUs' longstanding right to propose reasonable adjustments to the base estimates produced by Commission-approved methodologies to support the case for funding for necessary work. Indeed, as the climate continues to change rapidly, the spending record of the past may not be a reliable predictor of future activities that are necessary to provide customers with safe and reliable service. Rendering it more difficult for the IOUs to obtain an appropriate revenue requirement was not intended or required by the Commission's guidance on forecasting methodologies, and no precedent was provided to support TURN's position.

TURN also provides new criteria that the utility would need to follow to overcome the rebuttable presumption to obtain any increase in costs above the proposed base estimate adjusted

---

[15] *See id.*at Slide 6.

[16] *Id.*at Slide 7.

[17] *See id.* at Slide 8.

by inflation proxy. These hurdles include limitations on the amount and type of O&M adjustments, handling of one-time costs, a requirement to absorb cost increases due to customer growth, rules regarding unit costs, handling of vacant positions, and employee benefits. These additional conditions are not proposals intended to find some common ground, but instead are restatements or extensions of litigation positions that TURN has taken in various GRC proceedings. They would severely hamper or eliminate the IOUs' ability to make meaningful proposals or request reasonable funding. While the Joint IOUs support TURN's stated intention of making GRC proceedings more efficient, TURN's proposals would have the opposite effect. The new requirements to obtain cost recovery to provide just and reasonable service would increase rather than decrease the burdens of GRCs. More importantly, they would effectively erase forecast-based ratemaking as the operative regulatory framework. The IOUs would be left with the burden to prove requests are reasonable, but in numerous instances, would not even be allowed to propose forecasts regardless of the acuity of the need for additional funding. This does not further the goals of the workshop to increase the efficiency of GRC proceedings and appears to cancel out fundamental principles of forecast-based ratemaking that the Commission has long relied upon to make informed decisions in each IOU's GRC.[18]

[18] TURN's proposals are based upon certain sweeping assumptions concerning utility spending and needs. *See* TURN Rebuttable Presumption Presentation at Slide 7. When asked for the basis or underpinning of these assumptions, TURN did not identify any such basis or underpinning, and stated that its proposal was merely an opening position for discussion.

Topic 2: Standardized Attrition Year Ratemaking

For the Attrition Mechanism, the Joint IOUs proposed several rebuttable presumptions for consideration by stakeholders. The presumptions proposed include the following: that O&M and capital would have distinct treatment, implementation of the attrition year adjustment by advice letter, use of escalation indices that reflect of the basket of goods utilized by utilities, the inclusion of ratified collective bargaining agreements, and adoption of capital additions as the capital adjustments.[19]

TURN presented a philosophical approach to the purpose and need for an attrition mechanism with which the Joint IOUs cannot agree. TURN proposes the "Commission presume that an attrition year adjustment mechanism should be adopted in each GRC that escalates O&M expenses by the Consumer Price Index – Urban inflation rate."[20] TURN proposes "the Commission presume that an attrition adjustment mechanism should be adopted in each GRC that calculates capital related costs based on historical capital trending. The historical capital trending should include a 7-year average of recorded capital additions, including the 5 years prior to the base year, the base year, and once available, the base year plus 1. Capital additions from each year should be expressed in constant (base year) dollars and may be normalized to the

[19] *See* Draft Report, Appendix A, Chapter 9.4, IOU Presentation "Standardizing Attrition Mechanisms" at Slides 6-13. Like the Joint IOU proposal for stipulated terms and rebuttable presumptions, these proposals are grounded in Commission precedent. *See, e.g.*, D.19-09-051 at 706-07 ("We agree with Applicants that the [post-test year ("PTY")] mechanism for capital additions should reflect projected capital additions rather than just escalation."); *id. at* 707 ("Since O&M expenses and capital expenditures affect the revenue requirement differently, we find that a two-part attrition mechanism, where O&M expenses and capital-related revenues are separately escalated, is reasonable. Therefore, we find it reasonable to apply different [Post-Test Year] mechanisms for O&M and for capital additions.").

[20] *See* Draft Report, Appendix A, Chapter 9.5, TURN, Standardizing Attrition Year Revenue Requirement Adjustments ("TURN Attrition Presentation") at Slide 5.

number of customers in each year before averaging."[21] TURN also proposes that a utility overcoming this presumption must show that the "capital attrition adjustment provided by this mechanism will be grossly inadequate"[22] and that attrition year capital budgets for programs that are not "mandated or law or regulation" would be subject to a later true up.[23]

While the Joint IOUs agree with TURN that use of an index is appropriate in an attrition year adjustment for operating expenses, the Joint IOUs believe the index should reflect the basket of goods and services employed by the IOUs. TURN's proposals for an attrition year escalation index does not reflect a utility's costs and services.[24] Because each of the IOUs currently has an open GRC proceeding where the amount of the attrition year revenue requirement is at issue, the IOUs cannot substantively address each of TURN's proposals for the attrition year, which the IOUs have generally successfully opposed in numerous rate cases. As an example, the use of CPI was litigated in PG&E's 2014 GRC due to a proposal of the Division of Ratepayer Advocates. The Commission declined the proposal, finding, "[t]he CPI measures changes in consumer prices and is not the best proxy for a wage index."[25] The Commission also declined to require the use of the CPI in SCE's 2004 GRC, finding that it is not "a measure of price changes faced by an electric utility."[26] Most recently, the Commission again rejected the use of CPI in 2019 when it again declined TURN's proposal in SoCalGas' and SDG&E's 2019

---

[21] *See id.* at Slide 5.

[22] *See id*. at Slide 6.

[23] *See id.*

[24] *See* Draft Report, Appendix A, Chapter 9.4, IOU Presentation at Slide 10. ("Broad indices that reflect inflationary pressures for goods and services in general do not accurately reflect the specific basket of goods and services that the utility employs on behalf of its customers.").

[25] D.14-08-032 at 527.

[26] D.04-07-022 at 278.

GRC, stating, "We find that Global Insight escalation rates are specific to the utility industry and more accurately reflects [the utilities'] inflationary cost increases. In contrast, escalation based on CPI, which is a broad wholesale pricing index, [reflects] price increases for goods and services in general and does not sufficiently capture the O&M escalation inputs of [the utilities]."[27] Similarly, the Commission declined to adopt a CPI-based escalation in SCE's recent 2015 and 2018 GRC Decisions.[28] As TURN's proposal recasts litigation positions in pending GRCs, the Joint IOUs do not believe an informal resolution to these issues will be reached by the workshop parties.

III. CONCLUSION

As described above, the proposals in Workshop 1 did not achieve an agreed-upon result. The RCP Decision requires no further action on these proposals. The workshop parties appear to be far apart on these issues, and the Joint IOUs are not optimistic that common ground can be achieved through debating litigation positions that were resolved in prior Commission decisions. The Joint IOUs look forward to participating in the upcoming workshops and remain optimistic that consensus among the parties on some of the other workshop topics may be achievable.

Respectfully submitted,

By: /s/ Sharon L. Cohen

Sharon L. Cohen
Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court, CP32D
San Diego, California 92123-1530
Telephone: (619) 696-4355
E-mail: SLCohen@sdge.com

September 29, 2020

[27] D.19-09-051 at 708. *See also*, *id.* at 707 ("We also find that applying a percentage increase that is based on the Consumer Price Index (CPI) does not reflect how utilities incur costs.").

[28] D.15-11-021 at 390-391; D.19-05-020 at 285-286.

GENERAL RATE CASE PLAN WORKSHOP #2 REPORT

GRC Standardization

1. Table of Contents

2. Executive Summary

On October 7, 2020, the California Public Utilities Commission's (CPUC) Energy Division (ED) hosted the second in a series of workshops to explore standardizing the organization and format of General Rate Case (GRC) filings for the large California energy utilities. The workshops were ordered in Decision (D.) 20-01-002, which modified the Commission's rate case plan for the large energy utilities. The objective of the workshops is to further explore and develop proposals to increase the efficiency of GRC proceedings. The scope of the second workshop was to consider standardization of GRC filings, specifically including the Master Data Request (MDR), Joint Comparison Exhibit (JCE), testimony chapter structure, Phase 2 and gas allocation case scheduling and standardization, base year and recorded spending data, and bill impact calculations.

In addition to CPUC staff, identified attendees at the workshop included Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), The Utility Reform Network (TURN), the CPUC Public Advocates Office (Cal Advocates), Liberty Utilities, and Bear Valley Electric Service.

The workshop scope included six topics:

- Standardization of the MDR
- Standardization of the JCE
- Standardization of Testimony Chapter Structure
- Phase 2 and Allocation Case Scheduling and Standardization
- Base Year and Recorded Spending Data
- Standardized Bill Impact Calculations

On behalf of the joint investor-owned utilities (SCE, PG&E, SoCalGas, and SDG&E; collectively "IOUs"), PG&E presented guiding principles and other proposals for all topics except for developing a standard testimony chapter structure. SCE presented the IOUs' position on the testimony chapter structure topic. ED, Cal Advocates, and TURN were active in the discussion of the IOU proposals. Below is a high-level summary of the workshop discussion:

- **MDR**: The IOUs recommended removing MDR questions that are duplicative, outdated, or not possible to address. The IOUs also recommended providing MDR responses 30 days
  after filing the application. Cal Advocates' preference is to work individually with IOUs on specific refinements and to receive MDR responses at the same time the IOU's GRC application is served. TURN provided four recommendations to make it easier for intervenors to use the MDR, including a standard index of MDR question areas, posting the responses on the IOU's website, sending a notice to the service list when the responses are posted, and including TURN in future discussions on the MDR at the appropriate time to consider the addition of typical data requests from TURN.
- **JCE**: The IOUs recommended a standardized layout for the JCE that provides opportunities for IOUs to tailor certain components where appropriate. The IOUs also recommended submitting the JCE 2-4 weeks after hearings. No feedback was received during the workshop on the IOU proposal for JCE standardization.

- **Testimony Chapter Structure**: The IOUs did not propose any changes to testimony chapter structure. No other party proposed changes to the status quo on this topic during the workshop.
- **Phase 2 issues**: The IOUs made a series of proposals to improve the efficiency of filing sequencing for GRC Phase 2 and gas allocation cases. TURN stated that PG&E's proposal for filing its GRC Phase 2 is counter to the goal of standardization, at least after an initial transitional schedule, and also suggested PG&E should be able to combine its gas rate design and allocation proceedings. ED reiterated that schedule changes cannot be approved at the workshop and that the purpose of the workshop is to gather information. The IOUs noted that the question of how to implement recommendations needs to be addressed for issues discussed in the workshops and that the IOUs would make a proposal for how to proceed on each of the workshop issues, both consensus items and contested items.
- **Base Year and Recorded Spending Data**: The IOUs recommended making base-year-plus-one recorded data available through the discovery process in the late first quarter of the following year. TURN proposed that base-year-plus-one recorded data should be provided by the IOUs by no later than March 1 through an automatic process, rather than through the discovery process. In the event the IOUs cannot provide the data by March 1, TURN proposed that evidentiary hearings be delayed to April 15. Cal Advocates agreed with TURN that base-year-plus-one recorded data should be provided as an automatic standing item. The IOUs will review and consider this feedback from Cal Advocates and TURN.
- **Bill Impact Calculations**: The IOUs presented a standard format for providing bill impact calculations by climate zone, seasonally and annually, for CARE and non-CARE customers. ED made recommendations to improve the clarity of the bill impact presentation. To capture the long-term rate effects of proposed capital spending, TURN proposed providing annual bill impact calculations for 10 years and then every 5-10 years thereafter,

covering 40 years overall. The IOUs will review and consider this feedback from ED and TURN.

On October 14, TURN submitted comments on the workshop, which reiterated and expanded upon the recommendations TURN made during the workshop discussion. A draft version of this workshop report was circulated for comment on October 22. The IOUs submitted comments on October 30, which summarized points made during the workshop and responded to TURN's October 14 comments.

3. Introduction

On October 7, 2020, ED hosted the second in a series of workshops to explore standardizing the organization and format of GRC filings for the large California energy utilities. The large energy utilities are PG&E, SCE, SDG&E, and SoCalGas. The workshops were ordered in D.20-01-002, which modified the Commission's rate case plan for energy utilities. The objective of the workshops is to further explore and develop proposals to increase the efficiency of GRC proceedings. The scope of the second workshop was to consider standardization of GRC filings, specifically including the MDR, JCE, testimony chapter structure, Phase 2 and gas allocation case scheduling and standardization, recorded base year data, and bill impact calculations. The workshop was facilitated by ED with support from PG&E.

4. Background

On January 16, 2020, the Commission issued D.20-01-002 (the "Decision Modifying the Commission's Rate Case Plan for Energy Utilities" in Rulemaking (R.)13-11-006). D.20-01-002 adopted changes to the Rate Case Plan for large California energy utilities to enable the Commission to conduct GRC proceedings more efficiently, including modifications to the GRC procedural schedule and extending the GRC cycle for each utility from three years to four years. R.13-11-006 was closed upon CPUC adoption of D.20-01-002.

The RCP decision also ordered a series of workshops to explore and develop proposals to increase the efficiency of GRC proceedings. CPUC staff identified four workshops and invited parties to provide feedback on the scope of each workshop:

1. Stipulated Terms / Rebuttable Presumptions / Standardized Attrition Year Ratemaking
2. Standardization of GRC Filings
3. Results of Operations (RO) Model Uniformity
4. Standardization of RAMP Filings

The IOUs (SoCalGas, SDG&E, PG&E, and SCE) are supporting CPUC staff in facilitating the workshops, and an IOU has been designated for each workshop. The

RCP Decision also requires that no later than 30 days after the conclusion of the workshop, the designated IOU shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies served on the service list of R.13-11-006 summarizing the workshop and any agreed-upon proposals.

5. Workshop

ED held the second public workshop virtually via a recorded WebEx session on October 7, 2020. Due to the state's public health order in response to the COVID-19 pandemic, there was no in-person attendance. ED sent notice of the workshop to the service list for R.13-11-006. The public workshop notice was posted on the CPUC's Daily Calendar and website. The workshop, scheduled from 10:00 AM – 4:00 pm, included six main agenda topics:

- Standardization of the MDR
- Standardization of the JCE

- Standardization of Testimony Chapter Structure
- Phase 2 and Allocation Case Scheduling and Standardization
- Base Year and Recorded Spending Data
- Standardized Bill Impact Calculations

Participants were required to pre-register for the workshop. ED staff kicked off the workshop by outlining the workshop agenda, background, objectives, and logistics. In addition to CPUC staff, identified attendees at the workshop included PG&E, SCE, SDG&E, SoCalGas, The Utility Reform Network (TURN), the CPUC Public Advocates Office (Cal Advocates), Liberty Utilities, and Bear Valley Electric Service.

6. Topic 1: Master Data Request

6.1 IOU Presentation on the MDR

On behalf of the IOUs, PG&E presented guiding principles that the IOUs agree should be used to make the MDR more efficient and useful. These principles are as follows:

- General Requirements and Standard Requirements List of Documentation Supporting an Application formatted as a checklist; i.e. the company has complied with the following requirements (and list the requirements) instead of a generic response for each individual question.
- Remove questions that are duplicative because they ask for information readily available within the testimony and or workpapers or could be directly derived from the testimony and workpapers.
- Remove questions that are outdated or no longer useful to Cal Advocates.
- Remove questions that ask for the exact same information presented in a different way.
- Subject to Cal Advocates' review, remove questions with no follow-up data requests or cites in Cal Advocates testimony, in the context of the fact that:
    - a) Are we answering questions efficiently so there is no follow up needed or are the questions and responses not useful.
    - b) The questions themselves do not directly pertain to the General Rate Case.
- Remove (or change) questions where historical experience has

consistently demonstrated that it is not possible to provide a response after reasonable inquiry and effort.

In terms of process and timing, the IOUs propose that it would be beneficial to submit the responses to the MDR no later than 30 days after the filing of the application.

6.2Discussion on the IOUs' Presentation

ED asked whether it would be the responsibility of the IOU to notify intervenors when previously unavailable information in the MDR becomes available. PG&E responded that it would not be incumbent on IOUs to do so. PG&E explained that the intent of the streamlining proposal is to find areas where questions have been asked in numerous previous GRC cycles and the IOU consistently responded that it was not possible to provide such information, in order to focus efforts on content that is useful.

SDG&E/SoCalGas noted that it would make sense to work together to find an alternate solution that provides information of value but noted that they have provided the same response to the same MDR question many times in multiple chapters of the MDR, indicating that certain requested information is not available.

Cal Advocates stated that it is happy to work with the IOUs on the MDR on an individual basis. Cal Advocates' preference is to continue to author and retain the MDR, and work individually with the IOUs on specific refinements. Further, Cal Advocates noted that the MDR has no impact on the Commission's processing of an application and does not lead to delay. The MDR enhances Cal Advocates' understanding of an application and becomes an input in its analysis of an application, even if Cal Advocates does not necessarily cite to information from the MDR in testimony. Cal Advocates also noted its preference for the MDR to continue to be available when the IOU's GRC application is served, but it is open to further discussion on timing.

TURN stated that the IOUs should improve public access to non-confidential information that is routinely provided through the MDR to reduce the need for discovery by intervenors that may duplicate some of the questions in the MDR. TURN provided four recommendations to make it easier for intervenors to use the MDR:

1. A Standard Index of MDR Question Areas: TURN recognizes that the questions in each MDR would not be the same due to an IOU's distinct characteristics. However, a common index of question areas would be very helpful. This would include a common numbering system; for example, MDR Section Eight could consistently focus on administrative and general (A&G) issues.
2. Public Version of MDR Questions and IOU Responses Posted on the IOU's GRC Webpage: TURN proposes that any interested intervenor or member of the public have easy access to the MDR responses through the IOU's website. TURN stated that it routinely

requests the IOU's responses to an MDR and is provided with them upon execution of a non-disclosure agreement. TURN noted that there is generally limited confidential information in the response, but the whole response receives confidential treatment, slowing the process of receiving the information. TURN proposed that non-confidential responses be posted publicly.

3. The IOU to Send a Notice to the Service List when Responses are Posted on its Website: TURN proposed this so that intervenors would have quick access to this information and be able to review it before developing their own list of questions. TURN defers to Cal Advocates on the timeline and the appropriateness of the IOUs' 30-day response proposal.
4. TURN would like the IOUs to consider including its routine questions in the MDR: TURN has questions it routinely requests in each GRC and would like to make the process more efficient for everyone by incorporating those questions into the MDR. TURN would like to be invited to future discussions at the appropriate time.

PG&E agreed to review TURN's proposals. SCE also noted that it would consider the proposals and would need time to do so since they were not previously available in written form. TURN responded that the proposals were previously submitted in writing as feedback on the Rate Case Plan Workshop Plan in July.

6.3Post Workshop Comments on the MDR

In its October 14 comments, TURN reiterated the points made at the workshop and also proposed that an MDR template should be circulated to regular GRC intervenors for possible expansion to include questions routinely asked by intervenors through discovery (see Appendix B for TURN's comments).

In the October 30 IOU comments, the IOUs stated that they support Cal Advocates' inclinations with respect to JCE standardization. Provided Cal Advocates agrees, the IOUs support TURN's proposals to include a standard index, table of contents, and numbering system consistent across IOUs. The IOUs would also support making non-confidential MDR content available to parties participating in a GRC proceeding, providing GRC parties with instructions and guidance for requesting confidential MDR responses, and notifying the service list when the MDR information is available. The IOUs do not support TURN's proposal to expand the MDR to include questions routinely asked by other intervenors through discovery, stating that this proposal would further increase the IOUs' burden to respond to the MDR, and would not necessarily add to the information that is available to participants in the proceeding. The IOUs argued that the intervenors should instead review the IOUs' testimony and workpapers to determine whether further discovery is needed (see Appendix B for the IOU comments).

7. Topic 2: Joint Comparison Exhibit

7.1IOU Presentation on the JCE

On behalf of the IOUs, PG&E presented guiding principles for a standardized JCE layout. The proposed layout includes the following sections:

1. Introduction explaining layout of the JCE
2. Expense (O&M) and Other Operating Revenue (OOR) Items

a. Comparison of test year forecast recommendations for contested items
b. Comparison Template Components:
    i. Testimony reference
    ii. Program/Project/Activity name or description
    iii. Witness Names
    iv. Contested items financial comparison table
    v. Succinct summary of Parties' positions on contested issues

3. Capital Items
    a. Comparison of test year, test year minus one, and when applicable, test year minus two forecasts recommendations for contested items
    b. Comparison Template Components:
        i. Testimony reference
        ii. Program/Project/Activity name or description
        iii. Witness Names
        iv. Contested items financial comparison table
        v. Succinct summary of Parties' positions on contested issues
4. Policy, Ratemaking, and Other Qualitative Items, Results of Operations, and Post-Test Year Ratemaking Items

a. Comparison Template Components:
    i. Testimony reference Program/Project/Activity name or description
    ii. Witness Names
    iii. Succinct summary of Parties' positions on contested issues
5. Forecast Summary Tables: Comparison of IOU Proposals to Cal Advocates Recommendations
    a. Format to be based on each IOU's accounting structure.
6. Results of Operations (RO) at Proposed Rates for Test Year and Attrition Years (as applicable): Comparison of Utility RO to Cal Advocates RO

The IOUs proposed the following for the process for preparing the JCE:

- IOU drafts the JCE, including the summary of all Parties' positions, according to the principles above
- IOU provides all Parties' 2-3 weeks to review and revise positions summaries
- IOU submits final JCE 2-4 weeks after hearings (align JCE with Update Testimony positions.)

7.2Discussion on the IOUs' Presentation

SCE noted that Section 3 of the proposed layout (Capital Items) would also include rate-based components, working cash, and tax issues. SCE also noted that preparation of the JCE requires substantial effort for the IOU and intervenors, and that the proposed standardization principles were developed with the goal of trying to streamline the document and improve the process for everyone.

No comments from other parties were made on the IOUs' JCE proposal during the workshop.

7.3Post Workshop Comments on the JCE

In its October 14 comments, TURN noted that the IOUs' proposals will not impact the resources required by TURN to prepare the JCE, which for TURN includes reviewing items and proposing edits to ensure the IOU has accurately summarized the positions. Given the resources required to prepare a JCE, TURN encourages the consideration in each GRC of whether a JCE will meaningfully assist the assigned Commissioner and ALJ in preparing a decision. TURN notes that preparation of a more limited and focused JCE (financial impacts without position summaries) would reduce workload. TURN supports the preparation of the JCE where the assigned Commissioner and ALJ(s) find it useful.

In the IOU comments, the IOUs supported TURN's proposals to limit the JCE to program forecasts. The IOUs would also support an approach where the JCE contains citations to the place(s) in the record where each party has set forth its position, but the JCE does not add any narrative description of such position. The IOUs also stated that if the ALJ(s) or the Assigned Commissioner for a proceeding request a reinstatement of the narrative description of parties' positions, the IOU can take the lead in developing the desired material.

8. Topic 3: Testimony Chapter Structure

8.1 IOU Presentation on Testimony Chapter Structure

SCE presented the IOUs' position on standardizing the organization of GRC prepared testimony. SCE made the following points related to the current organization of testimony chapters:

- IOUs typically organize their applications to mirror the organization of their business units
- Each IOU is generally consistent from rate case to rate case
- SCE 2021 GRC: significant changeover to organize across business unit lines, and provide showing based on how work is actually performed
- Triggered by feedback from GRC parties
- Took nearly one year of work to enable the changeover, including reconfiguration of financial data applications
- SCE's 2021 GRC explained the new organization, and provided a roadmap between new and prior testimony exhibits
- Terminology used for testimony chapters varies by IOU, with the use of similar but not identical terms

SCE then made the following points related to standardization:

- The IOUs have not received feedback from litigating parties or Administrative Law Judges (ALJ) that the differences in organization amongst IOUs present any barrier to assessing utility showing or finding items within the showing.
    - Have received feedback on importance of including roadmap that walks the reader through the organization of the showing, and explains any brand-new organizational approaches
    - Have received feedback on importance of mandatory workshops to walk participants through the application
- The IOUs discussed opportunities for standardization. After careful discussion, the IOUs are not proposing to make wholesale changes to ways

that each IOU currently orders and structures its rate case showing.

- Each IOU is harmonizing the showing to reflect how the IOU's operations and activities are structured and classified. Key is to have the IOU's GRC showing mapped to the "real life" structuring of the IOU and the work it performs
- Imposing a set of labeling and organization requirements would not take into account how each IOU's internal financial and data systems and programs operate in processing, categorizing, and reporting information
- It is critical to avoid inefficiencies and disruptions that would result if strict labeling, organization, and classification of information in GRC does not align with IOU's internal financial and data system structures
- It does not appear to be worthwhile to make burdensome and unproductive changes to internal IOU financial and data applications and activities to obtain relatively
modest gains in ease of reference across different IOUs' rate case showings

- The IOUs welcome discussion on how we can make the presentation of our respective rate case showings easier to navigate, recognizing that each IOU has differences in structure, activities, and programs

8.2 Discussion on the IOUs' Presentation

SDG&E/SoCalGas reiterated the points SCE made in the IOU presentation, noting that each IOU is organized to reflect its business.

ED asked whether the IOUs have actively reached out to parties and ALJs to see if there are recommendations for modifying the organization of the application. SCE responded that it contacted TURN, Cal Advocates, and ED to inform them of the organizational changes prior to filing its 2021 GRC.

TURN noted that the issue of standardizing the order of testimony chapters did not originate with TURN and it finds it helpful when each IOU maintains a similar structure to its prior GRC for comparison purposes. TURN is not proposing any changes to the status quo.

8.3 Post Workshop Comments on Testimony Chapter Structure

In its October 14 comments, TURN stated that it has learned to navigate the distinct approaches taken by the IOUs in presenting their GRC testimony. TURN provided no further comments on this topic.

In the IOU comments, the IOUs stated that they do not believe that further exploration of this topic would be useful or productive.

9. Topic 4: Phase 2 and Allocation Case Scheduling and Standardization

9.1 IOU Presentation on Phase 2 Issues

On behalf of the IOUs, PG&E presented on Phase 2 and gas allocation case issues, including discussion of the various upcoming cases and IOU scheduling concerns. The IOUs presented the following guiding principles:

- Minimize case delays with schedule to minimize overlap

- Provide sufficient time for implementation and subsequent post-implementation analysis prior to development of succeeding applications (in transition and ongoing)
- Schedule each IOU's Allocation Case(s) separately from its GRC Phase 1 schedule, as warranted

The presentation included the following proposals:

- PGE's next GRC Phase 2 to be filed in summer 2024 and every 4 years subsequently
- PG&E's next GCAP to be filed within 90 Days of Gas Transmission and Storage (GT&S) Cost Allocation and Rate Design (CARD) decision
    - PG&E will file GT&S CARD within 75 days of its 2023 GRC 1 application
- SDG&E/SoCalGas's next Triennial Cost Allocation Proceeding (TCAP) to be filed in the third quarter of 2023
- No changes to SCE's filing schedule

- GRC 2 Standardization: While the methods and range of proposals vary across IOUs and across applications, the following minimum elements would be included in all GRC 2 applications:
    - Cost of Service Methodology and Studies (including TOU period analysis)
    - Proposed Allocation of Revenue Requirement by Class/Service
    - Proposed Rate Design
    - Illustrative Bill Comparison Results
    - Electronic Work Papers

The presentation also included background information and charts showing the current and proposed sequencing schedule. Appendix A includes the full slide deck that was presented.

9.2 Discussion on the IOUs' Presentation

TURN noted that PG&E's proposal for its future Phase 2 filings would not be consistent with the other IOUs and would not help achieve standardization. TURN asked if there is an alternate proposal that would allow PG&E to align in the future rather than repeating the off-schedule proposal. PG&E responded that there are no substantial dependencies between the GRC Phase 1 and Phase 2 filings and that while the original schedule has a 90-day connection between the two filings, this is no longer necessary. PG&E believes, based on other filings and limited available resources, that the timing proposal made by the IOUs would improve efficiency and make the best use of the available time.

TURN noted that the GT&S revenue requirement has been combined with the GRC Phase 1 filing and asked if PG&E has considered combining the CARD and GCAP filings into one application. Later in the discussion, ED asked the same question. PG&E responded that this had been considered but not recommended due to the following factors: it would make a very big case for PG&E, which would be inefficient in terms of staffing availability and resources; it would make it difficult for GT&S CARD to be decided in time for concurrent implementation with GRC Phase 1 case, which is desired by parties and the wholesale market; parties from GT&S CARD and GCAP are different; and a bigger case could more easily become delayed. TURN commented that if PG&E can handle a GRC Phase 1 filing with

GT&S, it should also be able to handle a combined CARD and GCAP filing, which would be a smaller application.

PG&E provided a minor clarification to the presentation in term of timeline, noting that future GRC Phase 1 filings will be in the month of May, rather than March, as was shown in the slides (see Appendix A for the presentation slide decks).

ED asked whether the other IOUs are on board with proposals presented by PG&E. SDG&E/SoCalGas clarified that what was presented is also their proposal. SDG&E/SoCalGas explained that a change is needed in their TCAP schedule due to the change to the 4-year rate case cycle. Many of the cost studies used for allocation in the TCAP are based on data in the GRC Phase 1 filing, so it makes sense to move the TCAP filing to follow the GRC Phase 1 filing. Therefore, TCAP would be filed every 4 years rather than every 3 years. The IOUs reiterated that their proposals do not affect the timing of filings for any other IOUs besides PG&E and SDG&E/SoCalGas.

ED noted it had been provided with this proposal for the first time and wanted to confirm what Commission actions were being requested and what the appropriate procedural steps would be to implement those requests. PG&E confirmed that the IOUs are requesting the actions listed on presentation slide 14 (see Appendix A). Regarding GCAP, PG&E explained that there are other forums PG&E could use, including filing a Petition for Modification or request an extension. PG&E noted that an IOU can file a CARD proceeding of its own accord. For GRC Phase 2 filings, PG&E is requesting Commission permission to change the filing date.

ED asked what would happen if the Commission does not authorize the IOUs' proposals. SDG&E/SoCalGas replied that they will investigate the best way to ask CPUC, but if not authorized somehow, they would need to file a TCAP in third quarter of next year.
SDG&E/SoCalGas clarified that they are not asking for a rate freeze but rather would not update studies that allocate customer class allocations. PG&E responded that, currently, the GRC Phase 2 is scheduled to have a final decision in the same timeframe as the next GRC Phase 2 is filed. As a result, PG&E would not be able to implement the final decision and plan for its next application.

PG&E noted that the question of how to implement recommendations is common across the workshops and that the IOUs would make a proposal for how to implement recommendations following the completion of all four workshops.

ED suggested that the IOUs should describe how their proposals would be implemented and what the consequences of not approving them would be. ED also reiterated that nothing can be approved at the workshop and that the purpose of the workshop is to gather information.

9.3Post Workshop Comments on Phase 2 Issues

TURN's October 14 comments state that TURN is evaluating the implications of the IOUs' proposal and may offer recommendations after considering the draft

workshop report. TURN subsequently indicated that it has no recommendations at this time.

In the IOU comments, the IOUs responded to questions ED asked in the workshop concerning the consequences of the Commission not approving the IOUs' scheduling proposals and how the IOUs propose to effectuate their proposals. Regarding PG&E's GRC Phase 2, GCAP, and GT&S CARD, the comments stated that consequences include: disconnecting GT&S ratemaking from implementation of GT&S functional revenue requirement changes; a transitional five-year gap for both the PG&E GRC Phase 2 and GCAP; and inefficient use of the four-year rate case period for all concerned, with overlapping cases. Regarding proposal implementation, the GCAP proposal could be implemented through filing a Petition for Modification or a request for extension. The CARD proceeding can be filed of an IOU's own accord. For GRC Phase 2 filings, PG&E is requesting Commission permission to change the filing date. The IOUs' comments also reiterated that the IOUs would make a proposal for how to implement recommendations following the completion of all four workshops. SoCalGas and SDG&E noted that their proposal to move their cost allocation proceeding to occur every four years, and filing their next cost allocation proceeding in the third quarter of 2023, would avoid substantial scheduling overlap with the Track 2 schedule of the gas system reliability and planning rulemaking. Additionally, this schedule proposal would avoid scheduling overlap with PG&E's gas allocation cases, which would be an inefficient use of time for all concerned. SoCalGas/SDG&E are still analyzing the appropriate next steps for moving to a four-year cost allocation proceeding cycle. A likely procedural path discussed in the comments would be to file a Petition for Modification. SoCalGas/SDG&E will confer with CPUC staff before filing such a petition should SoCalGas and SDG&E seek this procedural path (see Appendix B for the IOU comments).

10. Topic 5: Base Year and Recorded Spending Data

10.1 IOU Presentation on Base Year and Recorded Spending Data

On behalf of the IOUs, PG&E presented on base year and recorded spending data. The presentation included the following background information:

- January 2020 RCP Decision 20-01-002: Agreement on a standard approach to "Base Year
  +1 data" should be an important topic for future workshops. Stakeholders should endeavor to reach consensus on a means of incorporating recorded spending data from the year of filing into every GRC on an agreed-upon schedule.
- On January 11, 2017, Energy Division hosted a GRC rate cycle workshop in Rulemaking R.13-11-016. The purpose of the workshop was to explore options that will help the Commission process GRC proceedings more efficiently and timely.
  - At the workshop, Cal Advocates and TURN proposed that the Commission move the base year to the year of the GRC filing, or streamline adding the filing year's recorded data into the GRC record.
  - IOUs explained that actual recorded data would be available after the financial close was complete for the year, typically several months after the end of the year.

The presentation then provided the following information on identification of the base year:

- Base Year: the most current year of completed recorded spending data at the time of a GRC filing

- In a three-year GRC cycle, the base year for a future GRC filing is the test year of the last
  GRC filing. For example, 2017 was the base year in PG&E's 2020 GRC
- In a four-year rate case cycle, the base year is the year after the test year of the last GRC, or test year minus 3 in the current GRC. For example, in PG&E's 2019 GT&S case, 2016 was the year after the test year of the 2015 GT&S rate case and the base year of the 2019 GT&S case

Finally, the presentation provided the IOUs' proposed approach for providing recorded spending data in the GRC:

1. Base Year Data: Use full year recorded data in the GRC application filing
2. Base Year Plus One Recorded Data: Data would be made available by late Q1 of the following year through the discovery process (the GRC hearings scheduled to be concluded by mid-March)

10.2 Discussion on the IOUs' Presentation

TURN noted that the IOUs' proposal to make base-year-plus-one recorded data available late in the first quarter of the year does not provide time for intervenors to make use of that data, as evidentiary hearings are scheduled to close by March 15. Citing D.20-01-002, TURN stated that the IOUs' proposal renders the base-year-plus-one recorded data useless for intervenors in the GRC proceeding and is therefore unacceptable. TURN proposed that the base-year-plus-one recorded data should instead be served by the IOUs by March 1. TURN also proposed that data be provided through an automatic process, rather than through the discovery process.

PG&E indicated that it is looking to improve its processes so that the data is available by March 1, but that providing the data is dependent in part on the timing of the U.S. Securities Exchange Commission (SEC)-regulated earnings call.

SCE stated that the base-year-plus-one recorded data would probably not be ready on March 1 due to data adjustments that need to take place and the new process of preparing the Risk Spending Accountability Report by the end of March, which may be the first time some of the data is available. SCE also noted that it will work to provide data as early as possible.

SDG&E/SoCalGas agreed with SCE and noted they worked to provide data as quickly as possible in their last GRC proceeding and were able to distribute it by mid-March. SDG&E/SoCalGas noted that they cannot commit to the requested March 1 date without first reexamining their internal process, including the Risk Spending Accountability Report.

TURN replied that if the IOUs cannot commit to the March 1 date, the only alternative is to postpone hearings to April 15 or later. SDG&E/SoCalGas asked whether there are other avenues to providing the data that achieve what TURN wants without slowing down hearings. TURN responded that it cannot rule out using the information in hearings. The IOUs will consider the issues raised by TURN.

Cal Advocates noted that it is happy to see five years of recorded data in the IOUs' presentation, as that data is important. Cal Advocates also agrees with TURN that base-year-plus-one recorded data should be provided as an automatic standing item rather than as a data request. Cal Advocates noted that the timing is to be determined.

10.3 Post Workshop Comments on Base Year and Recorded Spending Data

TURN's October 14 comments reiterated TURN's opposition to the IOUs' base-year-plus-one recorded data proposal and recommends the following changes to the RCP schedule to standardize incorporation of base-year-plus-one recorded data (*new events are in italics*):

Date	**Days**	**Event**
By February 25	~Day 285	Evidentiary hearings begin
Q1, By March 1	*~Day 290*	*Utility serves exhibit with BY+1 recorded spending data*
By March 15	*~Day 305*	*ALJ admits BY+1 recorded spending data exhibit into the record during evidentiary hearings or by written ruling*
By March 15	~Day 305	Evidentiary hearings end
By April 20	~Day 340	Briefs filed

TURN's comments also provided feedback on the presentation of historical spending data included with the GRC application. TURN supports the IOU proposal to provide 5 years of recorded data with their applications and recommends it be provided in the testimony, and in a table that also includes the forecast. TURN also recommends that the applicant include the authorized amount for the year in the historical series corresponding to the last test year.

In the IOU comments, the IOUs stated that they cannot commit to providing base-year-plus-one recorded data by March 1, as requested by TURN, but can commit to providing the data by March 31 and will endeavor to provide the data earlier. The comments also noted that if base-year-plus-one recorded data was provided on March 31, parties would still have 20 days to incorporate the data into their briefs. The IOUs also suggested that the base-year-plus-one recorded data be made available as part of the regular post-hearing update testimony so that parties can ask the witness sponsoring the data questions at the update hearing. The IOU comments also stated that the IOUs already include a table with five years of recorded data and test year forecast in testimony and/or workpapers. The IOUs do not agree with TURN's proposal to include the authorized amount for the year in the historical series corresponding to the last test year (which would be the year prior to the base year in the new 4-year GRC cycle). The IOUs stated that the prior authorized amount would not aid in the resolution of the reasonableness of the current forecast, but TURN could access the data and use it in its testimony if TURN disagrees (see Appendix B for the IOU comments).

11. Topic 6: Bill Impact Calculations

11.1 IOU Presentation on Bill Impact Calculations

On behalf of the IOUs, PG&E presented on standardized utility bill impact calculations, including the following guiding principles:

1. Calculate Historic Average Monthly Seasonal and Average Usage per

Individually Metered CARE and per Individually Metered non-CARE residential customer by Climate Zone for the most currently available calendar year at the time of GRC Phase 1 application

2. Using adopted rate design at the time of the GRC application apply adopted baseline allowances by Climate Zone, present rates and rates (CARE vs non-CARE) under the proposed GRC RRQ's to the seasonal and annual average monthly usage in each of the distributions in (1) to calculate illustrative average monthly present and proposed bills by season and the annual average
3. Calculate the absolute dollar and percent change in illustrative monthly average seasonal and annual average bills under the proposed change in GRC RRQ

The presentation included sample bill impact calculations for different climate zones by season (winter and summer) and annually (see Appendix A).

11.2 Discussion on the IOUs' Presentation

ED requested labelling the tables to clarify that they refer to bundled customers, which PG&E agreed was a good idea. ED asked if the bill impact calculations are just for basic baseline or combined baseline and all electric, or if the IOUs could provide a version for all-electric customers. PG&E replied that the current presentation is for basic baseline customers only and that it would explore doing an all-electric version as well.

TURN recommended including an additional line on each slide that indicates the service territory-wide information, rather than just by climate zone. ED requested a map of the baseline areas so that a customer could visually identify which climate zone applies to them. PG&E responded that it would consider how to incorporate these comments.

TURN stated that D.20-01-002 calls for consideration of the long-term impacts of capital investments on customer rates. TURN recommended that the tables be supplemented to model the bill impacts for the first 10 years, rather than just the first year. Considering that long term capital investments could have a useful life of 40 years, TURN suggested providing a calculation for every 5-10 years after the first 10 years. TURN noted that capital investments could distort customer rates in first year. TURN further stated that the decision calls for ongoing monitoring of rate impacts, and that the plain meaning of the decision is to go beyond the attrition years in the bill impact calculations.

PG&E responded that it interprets the decision as requesting what was presented and clarified that the IOUs' presentation showed bill impacts for 3 years in the GRC revenue requirement, which will be increased to 4 years as a result of the rate case plan change. SCE stated that it had the same interpretation as PG&E and questioned the value of providing 10 years of data, given other factors that could confuse the issue. SDG&E/SoCalGas asked how the IOUs would account for revenue requirement changes and forecast changes. TURN responded that the IOUs should incorporate forecasts to the extent they are available, or else hold other factors constant. TURN and the IOUs discussed when a capital addition could cause revenue requirement reductions in the early years of the investment, depending on tax attributes and depreciation. TURN stated that since a reduction in revenue requirements in early years is possible, the additional requested information needs to be presented in the GRC.

The IOUs will take TURN's feedback into consideration.

11.3 Post Workshop Comments on Bill Impact Calculations

TURN's October 14 comments reiterated the recommendations TURN made at the workshop, including: presenting bill impacts on a service-territory wide basis, in addition to by climate zone; and presenting the long-term revenue requirement impact of its proposed GRC capital spending, covering at least 10 years of impacts. TURN provided an example of an IOU showing on long-term revenue requirement impacts from proposed capital spending in its comments (see Appendix B). In addition, TURN's comments stated that the IOUs' proposal did not address the recommendation in ED's Preliminary RCP Workshop Plan to show the cumulative effect of the GRC rate change request with all other pending rate change requests. TURN believes this cumulative analysis would be useful in reviewing an IOU's GRC proposals and recommends that the IOUs amend their proposal to include it.

In the IOU comments, the IOUs agreed to implement changes proposed by ED, including labeling the bill impact tables to clarify that the table references bundled service customers, providing a version for all-electric customers, and providing a map of the baseline areas so that a customer could visually identify which climate zone applies to them. The IOUs also agreed to implement TURN's proposal to present the proposed bill impacts on a service territory-wide basis in addition to climate zone.

The IOUs disagreed with TURN's proposal to model bill impacts for 10 years and argued that the request is not supported by any Commission decision or guidance. The IOUs stated that providing calculations beyond the attrition years of a GRC application would involve providing information that is not informed by changes to customer and sales forecasts and revenue requirements and that the calculations would be incomplete and would provide customers with inaccurate information. The IOU comments also stated that aggregating outstanding rate increases for the purpose of determining rates or rate affordability is not in the scope of the workshop and does not appear ripe for implementation (see Appendix B for the IOU comments).

12. Next Steps

Following the presentations, SCE noted that there was an earlier question about how recommendations from the workshops would be approved by the Commission and whether a decision is needed as part of the workshops. SCE reiterated the IOUs' written comments on
Workshop 1, stating that the IOUs will make a procedural recommendation on how to implement proposals at the end of the workshops. SCE noted that this will be the appropriate time for such a recommendation, since the recommendation will be informed based on the discussion and feedback from all the workshops.

ED staff requested that comments be sent to the PG&E representative and to ED, and provided the following schedule for comments and the report:

- Workshop comments due October 14
- Draft report due October 23
- Comments on the draft report due October 30
- Final report issued November 6

ED thanked the workshop attendees and organizers and noted that the next Rate Case Plan workshop will be held in November.

13. Appendix A: Workshop Presentations

13.1 Energy Division Workshop Introduction

13.2 Standardization of the MDR

13.3 Standardization of the JCE

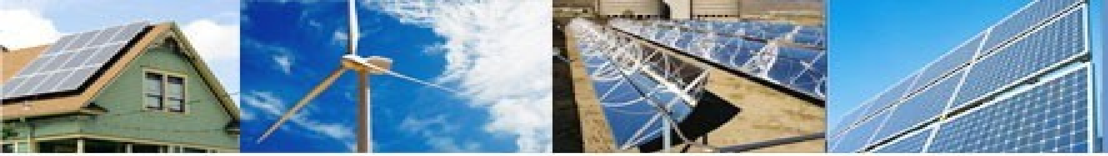
13.4 Standardization of Testimony Chapter Structure

13.5 Phase 2 and Allocation Case Scheduling and Standardization

13.6 Base Year and Recorded Spending Data

13.7 Standardized Bill Impact Calculations

13.1 Energy Division Workshop Introduction



Rate Case Plan (Decision 20-01-002) Workshop #2
General Rate Case Filing Standardization

October 7, 2020
10am – 4pm
California Public Utilities Commission (CPUC)

CPUC Energy Division
PG&E Lead

Workshop #2 Agenda

Item	Facilitator	Time
Introduction	CPUC	10:00 – 10:15 (15 min)
Master Data Request	Hannah Keller (PG&E)	10:15 – 10:40 (25 min)
Joint Comparison Exhibit	Greg Holisko (PG&E)	10:40 – 11:05 (25 min)
Break		11:05 – 11:15 (10 min)
Testimony Chapters Order	Greg Holisko (PG&E)	11:15 – 11:45 (30 min)
Lunch		11:45 – 12:30 (45 min)
Phase 2 Scheduling & Filing	Chris McRoberts (PG&E)	12:30 – 2:00 (90 min)
Break		2:00 – 2:15 (15 min)
Recorded Year Spending	Rebecca Katerndahl (PG&E)	2:15 – 2:55 (40 min)
Stretch Break		2:55 – 3:00 (5 min)
Bill Impact Calculation	Ken Niemi & Ben Kolnowski (PG&E)	3:00 – 3:30 (30 min)
Summary and Wrap-Up	CPUC	3:30 – 4:00 (30 min)

13.2 Standardization of the MDR

Rate Case Plan Workshop #2

Master Data Request

Hannah Keller
Case Manager, State and Regulatory Affairs
October 7th, 2020

Together, Building
a Better California

Master Data Request

PG&E, SCE, and SEMPRA agree that, in order to standardize and streamline the Master Data Request (MDR) to become more efficient and useful, there are several revisions that should be considered.

We have worked together to review each IOU's most recent General Rate Case MDR and have produced the following guiding principles.

Master Data Request

Principles:

- General Requirements and Standard Requirements List of Documentation Supporting an Application formatted as a checklist; i.e. the company has complied with the following requirements (and list the requirements) instead of a generic response for each individual question.

- Remove questions that are duplicative because they ask for information readily available within the testimony and or workpapers or could be directly derived from the testimony and workpapers.

- Remove questions that are outdated or no longer useful to Cal Advocates.

- Remove questions that ask for the exact same information presented in a different way.

Master Data Request

Principles Cont.:

- Subject to Cal Advocates' review, remove questions with no follow-up data requests or cites in Cal Advocates testimony, in the context of the fact that:

  a) Are we answering questions efficiently so there is no follow up needed or is the questions and responsive content not useful.
  b) The questions themselves do not directly pertain to the General Rate Case.

- Remove (or change) questions where historical experience has consistently demonstrated that it is not possible to provide a response after reasonable inquiry and effort.

Process and timing:

- The IOUs agree that it would be beneficial to submit the responses to the Master Data Request no later than 30 days after the filing of the application.

13.3 Standardization of the JCE

Rate Case Plan Workshop #2

Joint Comparison Exhibit Baseline Standardization Principles

Greg Holisko

Case Manager, State and Regulatory Affairs

October 7th, 2020

Together, Building a Better California

Joint Comparison Exhibit Layout

1. Introduction explaining layout of the JCE

2. Expense (O&M) and Other Operating Revenue (OOR) Items
   - Comparison of test year forecast recommendations for contested items
   - Comparison Template Components:
     - Testimony reference
     - Program/Project/Activity name or description
     - Witness Names
     - Contested items financial comparison table
     - Succinct summary of Parties' positions on contested issues

JCE Layout, Continued

3. Capital Items
    - Comparison of test year, test year minus one, and when applicable, test year minus two forecasts recommendations for contested items
    - Comparison Template Components:
        - Testimony reference
        - Program/Project/Activity name or description
        - Witness Names
        - Contested items financial comparison table
        - Succinct summary of Parties' positions on contested issues

4. Policy, Ratemaking, and Other Qualitative Items, Results of Operations, and Post-Test Year Ratemaking Items
    - Comparison Template Components:
    - Testimony reference Program/Project/Activity name or description
    - Witness Names
    - Succinct summary of Parties' positions on contested issues

JCE Layout, Continued

6. Forecast Summary Tables: Comparison of Utility Proposals to Cal Advocates Recommendations
   - Format to be based on each utility's accounting structure.

7. Results of Operations (RO) at Proposed Rates for Test Year and Attrition Years (as applicable): Comparison of Utility RO to Cal Advocates RO

8. Process for Preparing JCE
   - Utility drafts the JCE, including the summary of all Parties' positions, according to the principles above
   - Utility provides all Parties' 2-3 weeks to review and revise positions summaries
   - Utility submits final JCE 2-4 weeks after hearings (align JCE with Update Testimony positions.)

Appendix: Examples

Together, Building
a Better California

Expense (O&M) and Other Operating Revenue (OOR) Items

PG&E's Position
MWC KK includes activities to operate the Natural Gas (NG) facilities and required clerical and engineering support. This function also includes: site management and support services; materials, such as chemicals and lube oil; and contracts associated with operating a safe and reliable plant. MWC KK is used by the Gateway Generating Station (GGS), the Colusa Generating Station (CGS) and the Humboldt Bay Generating Station (HBGS) for planning and performing routine operations for the NG units.[831]

PG&E forecasts expense costs of $12.8 million for 2020.[832]

Cal Advocates' Position
Cal Advocates recommends using 2017 recorded costs for PG&E's 2020 forecast amount:

1. The base year 2017 expense level reflects non-recurring costs for miscellaneous O&M costs.
2. Cal Advocates' forecast is higher than prior years 2013, 2014 and 2015 recorded levels.
3. Cal Advocates' forecast is comparable to PG&E's 2018 recorded expenses.[833]

TURN's Position
The major part of PG&E's forecast increase is due to CGS operations costs forecast rise to $4,640,000 from 2017 to 2018; however, CGS operations' recorded costs decreased in 2018 by $616,000 to $3,356,000. As a result, TURN supports Cal Advocates use of the last recorded year.[834]

Policy, Ratemaking, and Other Qualitative Items, Results of Operations, and Post-Test Year Ratemaking Items

PG&E's Position
PG&E is in the process of replacing the RIBA scoring approach with the RSE calculation, as set forth in the S-MAP Settlement Agreement, for scoring mitigation programs.[36]

TURN's Position
Beginning in 2020, PG&E should be directed to abandon its flawed Risk Informed Budget Allocation scoring approach and adopt in full the quantitative methodology set forth in the S-MAP settlement adopted in D.18-12-014 to inform PG&E's decisions about how to prioritize risk mitigation programs.[37]

13.4 Standardization of Testimony Chapter Structure

Rate Case Plan Workshop #2 - Ox

Ordering and Structuring Testimony Chapters in Utility General Rate Cases

Kris Vyas
SCE Law Department

Current Organization of Testimony Chapters

- IOUs typically organized their applications to mirror the organization of their business units
- Each IOU was generally consistent from rate case to rate case
  - SCE 2021 GRC: significant changeover to organize across business unit lines, and provide showing based on how work is actually performed
    - Triggered by feedback from GRC parties
    - Took nearly one year of work to enable the changeover, including reconfiguration of financial data applications
  - SCE's 2021 GRC explained new organization, and provided a roadmap between new and prior testimony exhibits
- Terminology used for testimony chapters: varies by utility, with the use of similar but not identical terms

Changing Organization of Rate Case Presentation

- Utilities have not received feedback from litigating parties or ALJs that the differences in organization amongst utilities present any barrier to assessing utility showing or finding items within the showing
  - Have received feedback on importance of including roadmap that walks the reader through the organization of the showing, and explains any brand-new organizational approaches
  - Have received feedback on importance of mandatory workshop that walks through the application
- IOUs discussed opportunities for standardization. After careful discussion, we are not proposing to make wholesale changes to ways that each IOU currently orders and structures its rate case showing
  - Each IOU is harmonizing the showing to how the IOU's operations and activities are structured and classified. Key is to have the utility's GRC showing map to the "real life" structuring of the utility and the work it performs
  - Imposing an inflexible set of labeling and organization requirements would not take into account how each utility's internal financial and data systems and programs operate in processing, categorizing, and reporting information
  - It is critical to avoid inefficiencies and disruptions that would result if strict labeling, organization, and classification of information in GRC does not align with utility's internal financial and data system structures
  - It does not appear to be worthwhile to make burdensome and unproductive changes to internal utility financial and data applications and activities to obtain relatively modest gains in ease of reference across different IOUs' rate case showings
- IOUs welcome discussion on how we can make the presentation of our respective rate case showings easier to navigate, recognizing that each IOU has differences in structure, activities, and programs

13.5 Phase 2 and Allocation Case Scheduling and Standardization

Rate Case Plan (RCP) Workshop #2

Efficient Scheduling of GCAPs, GRC 2s, GT&S CARDs, and TCAPS: Joint IOU Recommendations

October 7, 2020

Together, Building
a Better California

1. Overview of Topic

- Allocation Cases, IOU Scheduling Concerns, and Proposed Guiding Principles
- More Efficient Scheduling
- GRC 2 Filing Standardization Requirements
- Outcomes Requested From Workshop
- Appendix

2. Allocation Cases, IOU Scheduling Concerns, and Proposed Guiding Principles

- IOU Allocation Cases to Schedule Within Four Year RCP
- PG&E GRC 1 versus GT&S CARD versus GCAP
- IOU Allocation Case Scheduling Concerns
- Proposed Guiding Principles for Allocation Case Scheduling Across California IOU's

3. IOU Allocation Cases to Schedule Within Four Year RCP

	Pacific Gas and Electric Company (PG&E)	Sempra (Southern California Gas and San Diego Gas & Electric) (SoCalGas/SDG&E)	Southern California Edison Company (SCE)
Electric Rates	• General Rate Case Phase 2 (GRC 2)	• General Rate Case Phase 2 (GRC 2)	• General Rate Case Phase 2 (GRC 2)
Gas Rates	• Gas Cost Allocation Proceeding (GCAP) • Gas Transmission & Storage Cost Allocation and Rate Design (GT&S CARD)	• Triennial Cost Allocation Proceeding (TCAP)	

4. PG&E GRC 1 versus GT&S CARD versus GCAP

PG&E GRC 1

PG&E GT&S RATE CASE

PG&E GCAP

RRQ

Non-RRQ

PG&E GRC 1

PG&E GT&S CARD

PG&E GCAP

PG&E GRC 1

- Includes GT&S RRQ beginning in 2023 GRC
- Limited to Authorizing Revenue Requirements for Four-Year Rate Case Period

PG&E GT&S CARD

- Filed for Simultaneous Implementation with PG&E 2023 GRC 1 using GRC 1 Revenue requirement as present rates to see GT&S rate case proposal impacts.
- Market Structure, GT&S Services and related Gas Capacities, balancing rules, market concentration limits, long term contract limits
- Gas Billings and Throughput Forecasts
- Sharing Mechanism/Balancing Account Treatment of Revenues
- Gas Backbone, Local Transmission, and Storage Cost Allocation and Rate Design
- Backbone Transmission System Load Factors
- Core Gas Supply (c.f., chapter included in previous GT&S Rate Cases)
- Core Transport Agent (CTA)-related issues

PG&E GCAP

- Addresses all non-GT&S PG&E Gas Ratemaking;
- Incorporates Adopted GT&S CARD Throughput and Billings Forecasts
- Cost Studies, Allocations, and Rate Design concerning Distribution, Public Purpose Program Surcharges, and Core Procurement

5. IOU Allocation Case Concerns

1. Continue CPUC consideration of PG&E GT&S and GCAP issues in separate applications with GT&S CARD filed for Simultaneous Implementation with PG&E GRC 1 and GCAP Filed after CARD Decision

2. PG&E GRC 2 Future Filing Schedule Considers:
   A. 2020 GRC 2 Decision Timing (Expected in 3rd Qtr 2021) and ability to implement, analyze and prepare for the following application,
   B. SCE/SDG&E GRC 2 Timing to minimize overlap, and
   C. PG&E Resource Constraints, particularly timing of preparation and litigation of PG&E GCAP

3. Transition/timing of Sempra TCAP on Four-Year Cycle instead of Current Three-Year Cycle that minimizes overlap to extent possible with PG&E GCAP and GT&S CARD

4. Maintain Historic Required GRC 2 Filing Schedule of 90-Days Following GRC 1 application for SCE and SDG&E with ability for requesting extension and opportunity within Rate Design Windows

6. Proposed Guiding Principles for Allocation Case Scheduling Across California IOU's

1. **Minimize case delays with schedule to minimize overlap**
   - For each commodity across IOUs, that allows efficient oversight/participation by CPUC Staff, Public Advocates Office, and other parties within four-year rate case plan cycle
   - Within each IOU, to enhance IOU's ability to (a) develop application and testimony on-time, and (b) provide more timely responses to data requests.

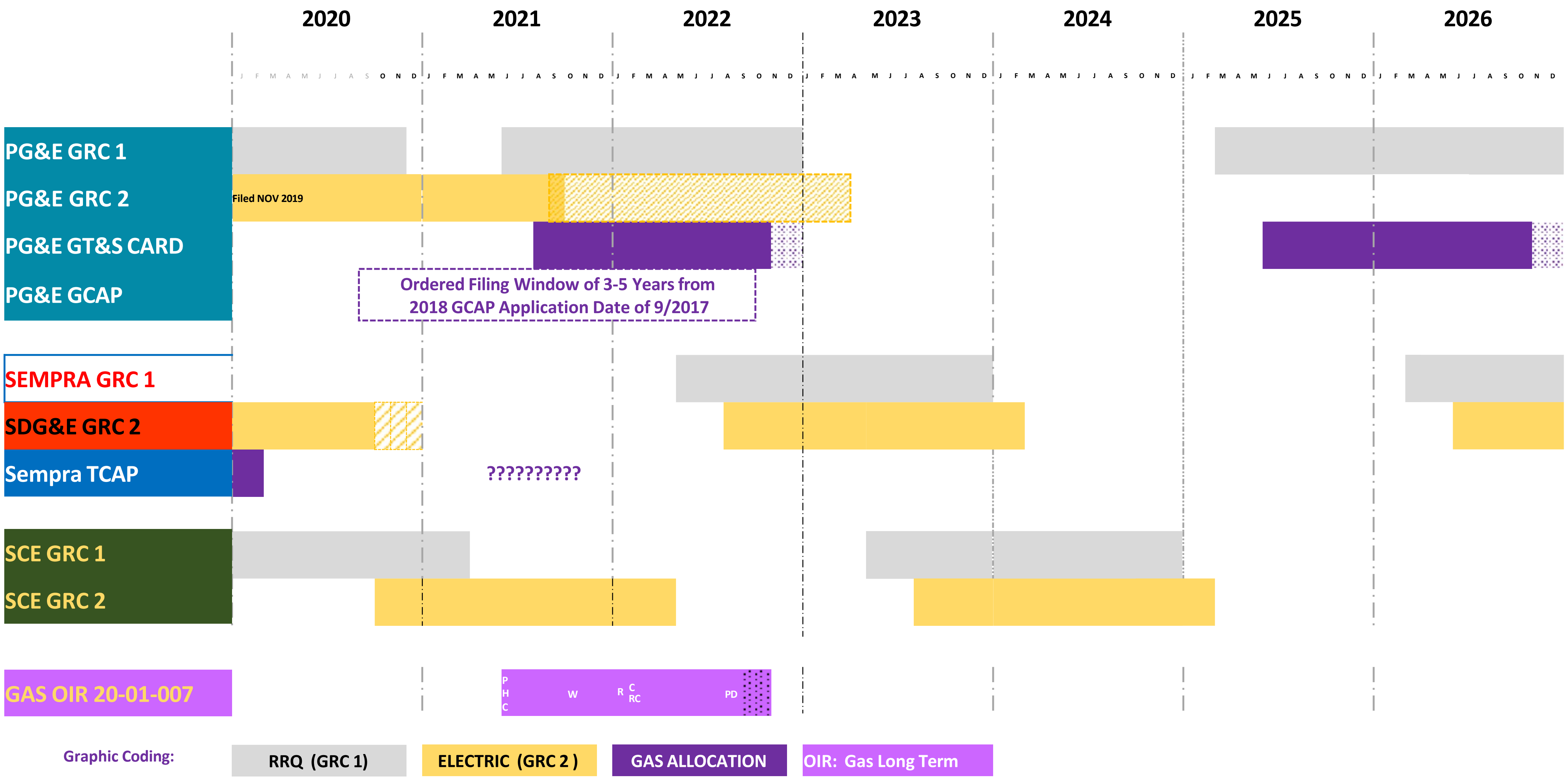
2. **Provide sufficient time for implementation and subsequent post-implementation analysis prior to development of succeeding Applications (in transition and ongoing)**

3. **Schedule each IOU's Allocation Case(s) vs its RCP GRC 1 schedule, as warranted**
   A. SCE and SDG&E: File GRC 2 within 90 days of scheduled GRC 1 application
   B. PG&E: Because PG&E's 2020 GRC 2 won't be decided until Fall '21, 90-day interval from 2023 GRC 1 is not workable. Due to linkage of gas wholesale market with GT&S CARD/GRC 1, PG&E should file GT&S CARD in 2021 (and every 4 yrs), and GRC 2 later.
      - GT&S CARD timed for simultaneous implementation with PG&E GRC 1 GT&S revenue requirement
   C. For Sempra TCAP and PG&E GRC 2, schedule to avoid inefficient overlaps per (1)

7. More Efficient Scheduling

- Step 1: Known Schedules As Starting Point
- Step 2: When Should PG&E's GRC 2's Be Filed?
- Step 3: When Should PG&E's GCAPs Be Filed?
- Step 4: When Should Sempra's TCAP be Scheduled?
- Summary: Allocation Case Four-Year Filing Cadence

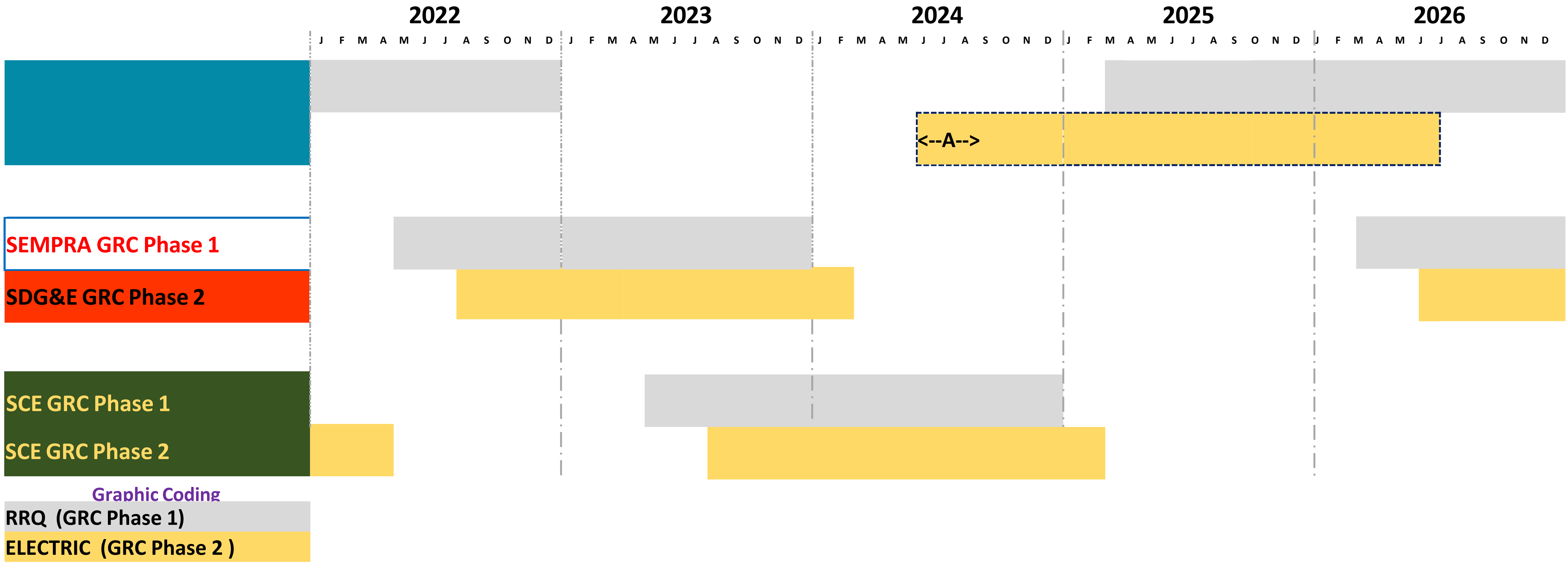
8. More Efficient Scheduling:
Step 1: Known Schedules As Starting Point



9. More Efficient Scheduling:
Step 2: When Should PG&E's GRC 2's Be Filed?

Filing PG&E's next GRC 2 in Summer of 2024 is most practical and expeditious timing:

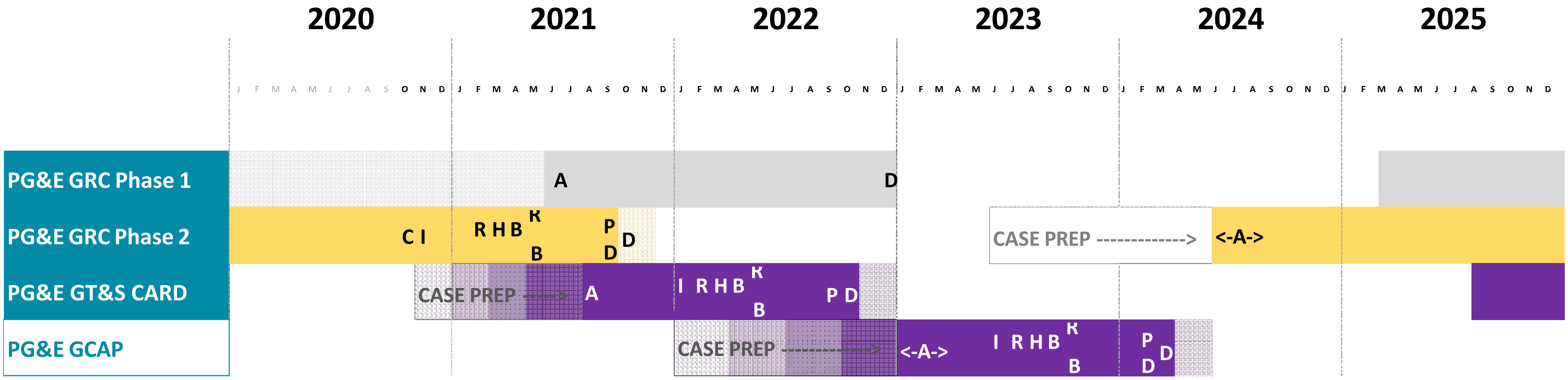
- Allows for a full year of usage under phased 2020 GRC 2 implementation before beginning case preparation
- Avoids overlap with SDG&E or SCE GRC 2's in 2022 or 2023 that could cause delays
- Prevents an even longer gap and parallel demand on PG&E resources (GT&S CARD) from filing in Summer 2025
- File every four years subsequently



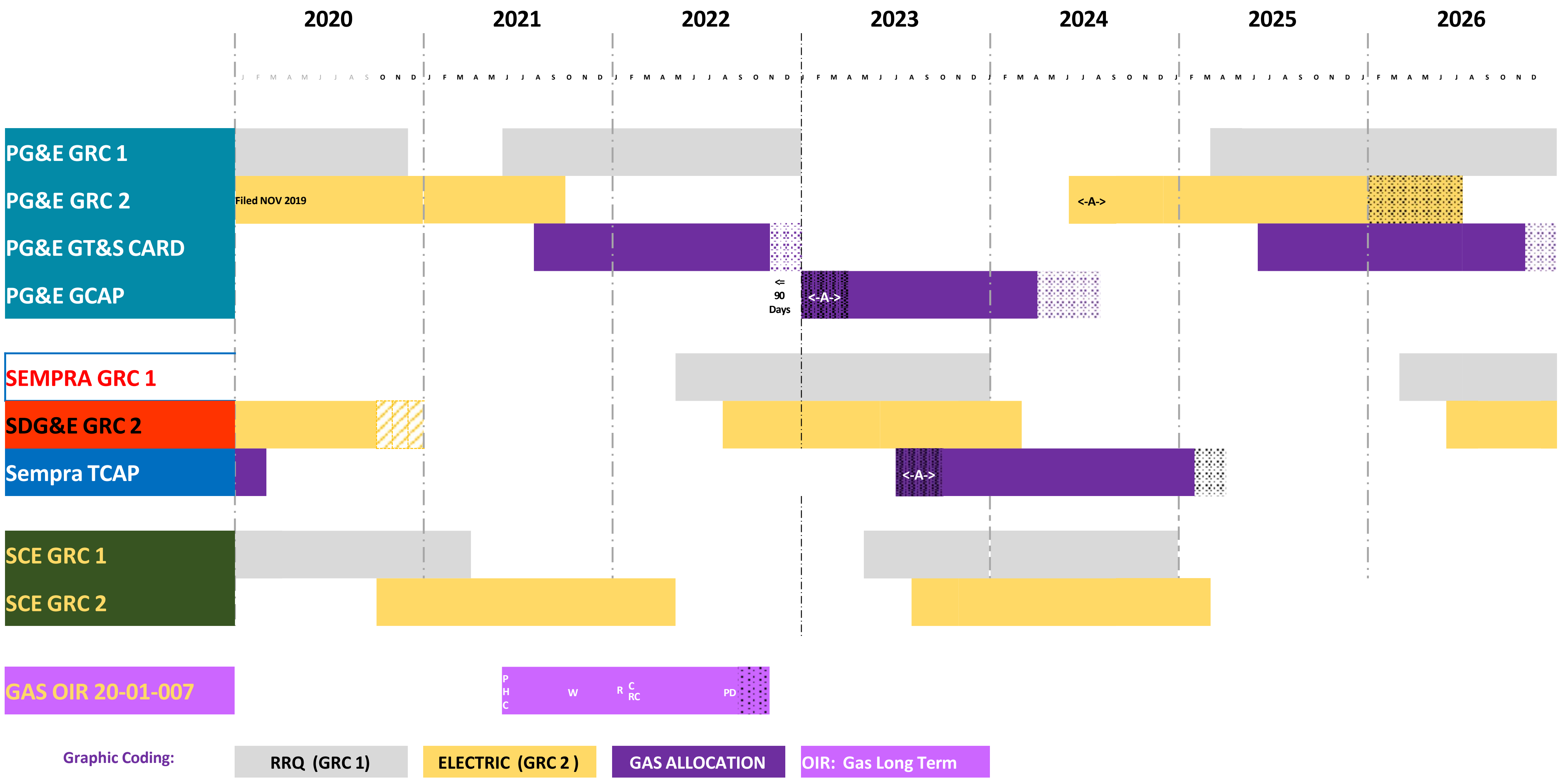
10. More Efficient Scheduling:
Step 3: When Should PG&E's GCAPs Be Filed?

Filing PG&E's Next GCAP within 90 Days of GT&S CARD decision is most practical:

- Allows Incorporation of Gas Throughput Forecast Adopted in 2023 GT&S CARD while still relevant
- Avoids overlap for PG&E Staff supporting GRC 2 in 2023/24 and GT&S in 2021/22
- One-time delay of ~5 months beyond the 3-5 year period from 9/2017 required in 2018 GCAP Decision
- Subsequently filed within 90 days of each GT&S CARD decision



11. More Efficient Scheduling:
Step 4: When Should Sempra's TCAP be Scheduled?



12. Summary: Allocation Case Four-Year Filing Cadence

Utility	Case	Filing Timeframe	Transitional Scheduling Issues	Other
PG&E	GT&S CARD	<= 75 Days After GRC 1	< =60 Days in 2021	Implemented with GRC 1 RRQ's
	GCAP	<= 90 Days from GT&S CARD Decision	One-time delay from D.19-10-036 3-5 Year OP 12	Incorporates GT&S CARD Throughput
	GRC 2	Filed Summer of Year Prior to GRC 1 Application Filing	Filed Summer 2024 instead of 2021	Use RDW's as warranted
Sempra	TCAP	Next TCAP Filed 3rd Qtr 2023		
SDG&E	GRC 2	File 90 Days After GRC 1	None	Use RDW's as warranted
SCE	GRC	File 90 Days After GRC 1	None	Use RDW's as warranted

13. GRC 2's Filing Standardization Requirements

While the methods and range of proposals vary across electric utilities and across applications, the following minimum elements would be included in all GRC 2 applications:

1. Cost of Service Methodology and Studies (including TOU period analysis)
2. Proposed Allocation of Revenue Requirement by Class/Service
3. Proposed Rate Design
4. Illustrative Bill Comparison Results
5. Electronic Work Papers

14. Outcomes Requested From Workshop

Existing Authority confirmed

- GT&S and GD Ratemaking for PG&E will be addressed in separate applications to allow GT&S ratemaking to be implemented with GRC 1 RRQ (*OP 4*)
- Submission of SDG&E and SCE GRC 2's 90 Days from GRC 1 Filing continues on a four-year cycle parallel with GRC 1 under RCP D. 20-01-02

Commission actions:

- Authorizes PG&E to file next GCAP within 90 days of 2023 GT&S CARD Decision, which would result in a one-time filing beyond the 3-5 year period authorized in D.19-10-036
- Authorizes PG&E's Next GRC 2 to be filed in Summer 2024 and every four years thereafter
- Authorizes Sempra to File TCAPs on Four-Year Cycle Commencing 3rd Qtr 2023

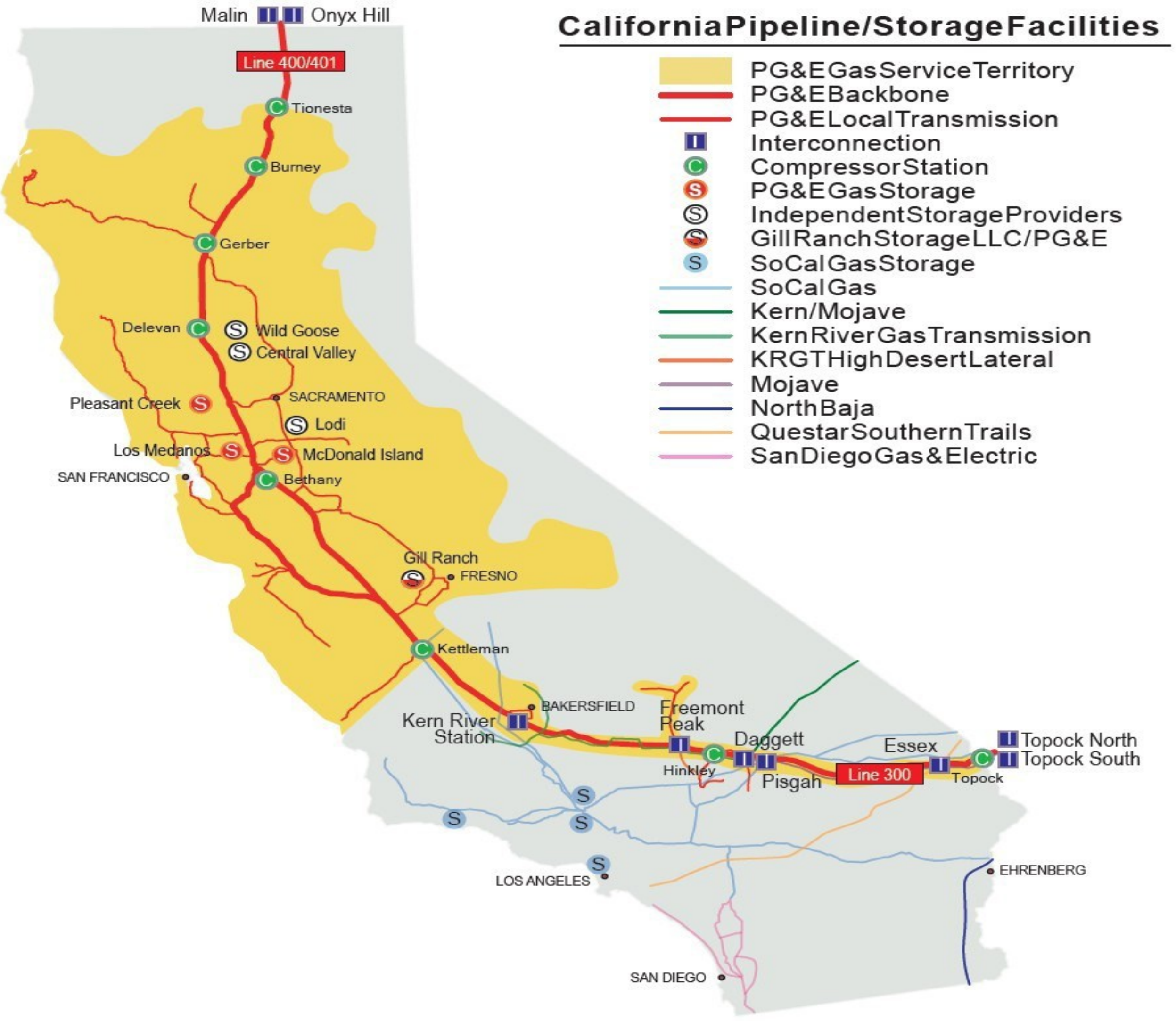
15. Appendix

A. PG&E Gas Transmission System

B. CPUC GT&S Scheduling Requirements

C. Gas Marketplace and GT&S Ratemaking

A. PG&E Gas Transmission System



B. CPUC GT&S Scheduling Requirements

GT&S Ratemaking:

- Because the Rate Case Plan Phase 1 decision (D.20-01-002) did not order GT&S ratemaking to be incorporated in PG&E's Gas Cost Allocation Proceedings (GCAP), and only ordered in (OP) 4 that GT&S Revenue Requirement proposals to be filed with PG&E's next GRC (in June 2021), the schedule for the rate design portion of PG&E's next GT&S is still governed by Ordering Paragraph (OP) 4 of D.19-09-025, which requires PG&E to file "in 2021" unless changed in the RCP proceeding.
- Accordingly, PG&E plans to file its GT&S rate design showing in Q3 2021, building from its GT&S revenue requirement to be filed in PG&E's 2023 GRC Ph 1 application in June 2021.

C. Gas Marketplace and GT&S Ratemaking

- **PG&E's Gas Transmission system provides service similar to Interstate Pipelines**
  - From California's borders with Oregon to Arizona and with interstate/Canadian connections to Gas Basins of western Canada, Rocky Mountains, New Mexico, and Western Texas
  - For Producers/Shippers, Marketers/Brokers/Core Transport Agents including PG&E Core Gas Supply, other Utilities, and large end-user customers acting as their own gas procurement agent
  - With impacts on CAISO Market through gas-fired electric generation located inside and out of PG&E's service territory

- **Goal for Western Gas Marketplace via Gas Accords that became GT&S Rate Cases (1998 to 2019)**
  - infrequent rate changes with revenue requirement and ratemaking changing simultaneously and efficiently for rate case participants, particularly market participants
  - Timely updates of the throughput forecast are needed and appropriate in an era of dynamic changes to gas demand
  - Unlike most other electric and gas revenues, PG&E's GT&S revenue is partially at risk under the Sharing Mechanism* and not subject to 100% balancing account treatment.

    * 50% of PG&E gas Backbone Transmission allocated to noncore and 25% of Local Transmission allocated to noncore is at risk

13.6 Base Year and Recorded Spending Data

Rate Case Plan Workshop #2

Base Year and Recorded Spending Data

Rebecca Katerndahl

Senior Manager, Revenue Requirements

October 7th, 2020

Together, Building a Better California

The Base Year and Requirements Regarding Recorded Data

- January 2020 RCP Decision 20-01-002: Agreement on a standard approach to “Base Year +1 data” should be an important topic for future workshops. Stakeholders should endeavor to reach consensus on a means of incorporating recorded spending data from the year of filing into every GRC on an agreed-upon schedule.

- Background: on January 11, 2017, Energy Division hosted a GRC rate cycle workshop in Rulemaking R.13-11-016. The purpose of the workshop was to explore options that will help the Commission process GRC proceedings more efficiently and timely.

  - At the workshop, Cal Advocates and TURN proposed that the Commission move the base year to the year of the GRC filing, or streamline adding the filing year’s recorded data into the GRC record.

  - IOUs explained that actual recorded data would be available after the financial close was complete for the year, typically several months after the end of the year.

Identification of the Base Year

- Base Year – the most current year of completed recorded spending data at time of a GRC filing

- In a three-year GRC cycle, the base year for a future GRC filing is the test year of the last GRC filing. For example, 2017 was the base year in PG&E's 2020 GRC

- In a four-year rate case cycle, the base year is the year after the test year of the last GRC, or test year minus 3 in the current GRC. For example, in PG&E's 2019 GT&S case, 2016 was the year after the test year of the 2015 GT&S rate case and the base year of the 2019 GT&S case

Base Year Recorded Spending Data

Description	PG&E Test Year 2027 GRC	SCE Test Year 2025 GRC	SDG&E / SoCalGas Test Year 2024 GRC
GRC Application Filing	May 15, 2025	May 15, 2023	May 15, 2022
5 Years of Recorded Data	2020-2024	2018-2022	2017-2021
Base Year (Test Year Minus 3)	2024	2022	2021
Base Year Recorded Data Available	By late Q1 2025	By late Q1 2023	By late Q1 2022
Base Year +1 Data Available	By late Q1 2026	By late Q1 2024	By late Q1 2023

Utilities' Proposed Approach of Providing Recorded Data:

1. Base Year Data
   - Use full year recorded data in the GRC application filing
2. Base Year +1 Recorded Data
   - Data would be made available by late Q1 through the discovery process (the GRC hearings scheduled to be concluded by mid March, per D. 20-01-002, Appendix A, Table 1)

Adopted Revised GRC Application Filing Schedule D. 20-01-002

Date	Days	Event
Test Year minus-1		
By January 30	~Day 260	Concurrent rebuttal testimony served
By February 25	~Day 285	Evidentiary hearings begin
By March 15	~Day 305	Evidentiary hearings end
To be decided		Update testimony and hearings, if necessary
By April 20	~Day 340	Briefs filed
By May 12	~Day 360	Reply briefs filed
By August 3	~Day 445	Status conference, proceeding submitted for Commission decision [Rule 13.14(a)]
By November 1	~Day 535	Proposed decision mailed for comment
By December 1	~Day 565	Final decision adopted
Test Year		
January 1	~Day 595	Effective date of final decision

13.7 Standardized Bill Impact Calculations

Rate Case Plan (RCP) Workshop #2

GRC Standard Bill Impact Calculation

October 7, 2020

Together, Building
a Better California

1. RCP Workshop #2: Topic 6

- RCP D. 20-01-002 Ordering Paragraph
- Standard Calculation of Residential Bill Impacts
- Standardized Electric and Gas GRC 1 Bill Impact Format Across IOU's
  - PG&E Presentation as Illustrative of All IOU Formats

2. Workshop #2 Topic 6: D.20-01-002 Compliance Item

- A standardized **Bill impact calculation:* the work for this topic would be completed off-line; and the utilities would "present their standardized calculation for discussion at the workshop…" (OP #6 D.20-01-002)

- *6. As a compliance item in this docket, Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company shall develop bill impact calculations for residential customers in the applicant's service territory, differentiated by usage in each climate zone, or other means as may be directed by the Commission or by the Director of the Energy Division, to be included in every future GRC application. The utilities shall present their standardized calculations for discussion at the workshop or workshops facilitated by the Energy Division, in consultation with the Safety and Enforcement Division, as needed, pursuant to Ordering Paragraph 5 of this decision.*

3. Standard Calculation of Residential Bill Impacts

1. Calculate Historic Average Monthly Seasonal and Average Usage per Individually Metered CARE and per Individually Metered non-CARE residential customer by Climate Zone for the most currently available calendar year at the time of GRC 1 application

2. Using adopted rate design at the time of the GRC application apply adopted baseline allowances by Climate Zone, present rates and rates (CARE vs non-CARE) under the proposed GRC RRQ's to the seasonal and annual average monthly usage in each of the distributions in (1) to calculate illustrative average monthly present and proposed bills by season and the annual average

3. Calculate the absolute $ and % change in illustrative monthly average seasonal and annual average bills under the proposed change in GRC RRQ

4. PG&E Residential Electric Bill Impact Format: Seasonal

Electric Bill Impact: Non-CARE, Summer

ELECTRIC BILL CHANGES	**SUMMER**										
	Avg. Mo.	Present	Proposed	$	%	Proposed	$	%	Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from	Rates	Chg from	Chg from	Rates	Chg from	Chg from
Non-CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present	1/1/2021	1/1/2020	1/1/2020	1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	545	$119.92	$129.10	$9.18	7.7%	$132.31	$3.21	2.5%	$135.86	$3.55	2.7%
Baseline Territory Coast Q	506	$122.69	$132.07	$9.38	7.6%	$135.35	$3.28	2.5%	$138.98	$3.62	2.7%
Baseline Territory Desert R	685	$156.55	$168.40	$11.84	7.6%	$172.54	$4.14	2.5%	$177.11	$4.57	2.7%
Baseline Territory Valley S	594	$133.54	$143.72	$10.17	7.6%	$147.28	$3.56	2.5%	$151.20	$3.92	2.7%
Baseline Territory Coast T	282	$58.82	$63.57	$4.75	8.1%	$65.23	$1.66	2.6%	$67.06	$1.83	2.8%
Baseline Territory Coast V	331	$69.11	$74.60	$5.49	7.9%	$76.53	$1.92	2.6%	$78.65	$2.12	2.8%
Baseline Territory Desert W	753	$173.78	$186.87	$13.10	7.5%	$191.45	$4.58	2.5%	$196.51	$5.05	2.6%
Baseline Territory Hills X	432	$94.98	$102.36	$7.37	7.8%	$104.93	$2.58	2.5%	$107.78	$2.85	2.7%
Baseline Territory Desert Y	399	$84.52	$91.13	$6.61	7.8%	$93.44	$2.31	2.5%	$95.99	$2.55	2.7%
Baseline Territory Desert Z	236	$47.46	$51.39	$3.93	8.3%	$52.76	$1.37	2.7%	$54.27	$1.51	2.9%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

5. PG&E Residential Electric Bill Impact Format: Seasonal

Electric Bill Impact: Non-CARE, Winter

ELECTRIC BILL CHANGES	**WINTER**												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
Non-CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	491	$107.41	$115.69	$8.28	7.7%		$118.58	$2.89	2.5%		$121.78	$3.20	2.7%
Baseline Territory Coast Q	585	$134.35	$144.57	$10.23	7.6%		$148.15	$3.58	2.5%		$152.10	$3.95	2.7%
Baseline Territory Desert R	440	$95.75	$103.18	$7.43	7.8%		$105.78	$2.60	2.5%		$108.65	$2.87	2.7%
Baseline Territory Valley S	457	$100.00	$107.74	$7.74	7.7%		$110.45	$2.71	2.5%		$113.43	$2.99	2.7%
Baseline Territory Coast T	340	$72.58	$78.32	$5.74	7.9%		$80.33	$2.01	2.6%		$82.55	$2.22	2.8%
Baseline Territory Coast V	413	$88.98	$95.92	$6.94	7.8%		$98.35	$2.43	2.5%		$101.02	$2.68	2.7%
Baseline Territory Desert W	391	$83.55	$90.09	$6.54	7.8%		$92.38	$2.29	2.5%		$94.91	$2.53	2.7%
Baseline Territory Hills X	453	$99.67	$107.38	$7.71	7.7%		$110.08	$2.70	2.5%		$113.06	$2.98	2.7%
Baseline Territory Desert Y	416	$85.62	$92.31	$6.69	7.8%		$94.65	$2.34	2.5%		$97.24	$2.59	2.7%
Baseline Territory Desert Z	258	$49.52	$53.59	$4.07	8.2%		$55.01	$1.42	2.7%		$56.59	$1.58	2.9%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

6. PG&E Residential Electric Bill Impact Format: Seasonal

Electric Bill Impact: CARE, Summer

ELECTRIC BILL CHANGES	SUMMER												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	534	$71.65	$77.32	$5.67	7.9%		$79.31	$1.99	2.6%		$81.50	$2.20	2.8%
Baseline Territory Coast Q	521	$78.16	$84.31	$6.15	7.9%		$86.47	$2.16	2.6%		$88.84	$2.38	2.7%
Baseline Territory Desert R	713	$101.71	$109.57	$7.86	7.7%		$112.32	$2.75	2.5%		$115.35	$3.03	2.7%
Baseline Territory Valley S	610	$85.08	$91.74	$6.65	7.8%		$94.07	$2.33	2.5%		$96.64	$2.57	2.7%
Baseline Territory Coast T	276	$33.89	$36.83	$2.94	8.7%		$37.86	$1.03	2.8%		$38.99	$1.13	3.0%
Baseline Territory Coast V	313	$38.38	$41.64	$3.26	8.5%		$42.78	$1.14	2.7%		$44.04	$1.26	2.9%
Baseline Territory Desert W	774	$111.35	$119.91	$8.56	7.7%		$122.90	$3.00	2.5%		$126.21	$3.31	2.7%
Baseline Territory Hills X	375	$47.68	$51.61	$3.93	8.3%		$52.99	$1.38	2.7%		$54.51	$1.52	2.9%
Baseline Territory Desert Y	454	$61.14	$66.06	$4.91	8.0%		$67.78	$1.72	2.6%		$69.68	$1.90	2.8%
Baseline Territory Desert Z	251	$30.54	$33.23	$2.70	8.8%		$34.18	$0.94	2.8%		$35.22	$1.04	3.0%

Illustrative rate and usage values from PG&E’s 2020 GRC Phase I

7. PG&E Residential Electric Bill Impact Format: Seasonal

Electric Bill Impact: CARE, Winter

ELECTRIC BILL CHANGES	WINTER												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
CARE Average Bill	per Cust	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	511	$69.45	$74.96	$5.52	7.9%		$76.89	$1.93	2.6%		$79.03	$2.13	2.8%
Baseline Territory Coast Q	661	$96.63	$104.12	$7.49	7.8%		$106.74	$2.62	2.5%		$109.64	$2.90	2.7%
Baseline Territory Desert R	429	$56.32	$60.89	$4.57	8.1%		$62.48	$1.59	2.6%		$64.25	$1.76	2.8%
Baseline Territory Valley S	443	$58.75	$63.49	$4.74	8.1%		$65.16	$1.66	2.6%		$66.99	$1.83	2.8%
Baseline Territory Coast T	327	$41.23	$44.69	$3.47	8.4%		$45.91	$1.22	2.7%		$47.25	$1.34	2.9%
Baseline Territory Coast V	389	$49.74	$53.82	$4.09	8.2%		$55.25	$1.43	2.7%		$56.83	$1.58	2.9%
Baseline Territory Desert W	390	$50.61	$54.76	$4.15	8.2%		$56.21	$1.45	2.7%		$57.81	$1.61	2.9%
Baseline Territory Hills X	409	$52.84	$57.15	$4.31	8.2%		$58.66	$1.51	2.6%		$60.33	$1.67	2.8%
Baseline Territory Desert Y	533	$73.11	$78.89	$5.78	7.9%		$80.91	$2.02	2.6%		$83.15	$2.24	2.8%
Baseline Territory Desert Z	312	$37.97	$41.21	$3.23	8.5%		$42.34	$1.13	2.8%		$43.59	$1.25	2.9%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

8. PG&E Residential Gas Bill Impact Format: Seasonal

Gas Bill Impact: Non-CARE, Summer

GAS BILL CHANGES	SUMMER										
	Avg. Mo.	Present	Proposed	$	%	Proposed	$	%	Proposed	$	%
	Therms	Rates	Rates	Chg from	Chg from	Rates	Chg from	Chg from	Rates	Chg from	Chg from
Non-CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present	1/1/2021	1/1/2020	1/1/2020	1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	22	$30.61	$31.85	$1.23	4.0%	$32.95	$1.11	3.5%	$34.07	$1.12	3.4%
Baseline Territory Desert R	17	$20.74	$21.60	$0.86	4.2%	$22.38	$0.78	3.6%	$23.16	$0.78	3.5%
Baseline Territory Valley S	18	$21.99	$22.90	$0.91	4.1%	$23.71	$0.82	3.6%	$24.54	$0.82	3.5%
Baseline Territory Coast T	26	$32.90	$34.18	$1.28	3.9%	$35.33	$1.15	3.4%	$36.49	$1.16	3.3%
Baseline Territory Coast V	31	$43.26	$44.93	$1.67	3.9%	$46.43	$1.50	3.3%	$47.94	$1.51	3.3%
Baseline Territory Desert W	17	$20.57	$21.43	$0.86	4.2%	$22.19	$0.77	3.6%	$22.97	$0.78	3.5%
Baseline Territory Hills X	23	$30.45	$31.65	$1.21	4.0%	$32.74	$1.08	3.4%	$33.83	$1.09	3.3%
Baseline Territory Desert Y	30	$40.33	$41.88	$1.55	3.8%	$43.28	$1.39	3.3%	$44.69	$1.41	3.3%

Illustrative rate and usage values from PG&E’s 2020 GRC Phase I

9. PG&E Residential Gas Bill Impact Format: Seasonal

Gas Bill Impact: Non-CARE, Winter

GAS BILL CHANGES	**WINTER**										
Non-CARE Average Bill	**Avg. Mo. Therms per Cust**	Present Rates 7/1/2018	Proposed Rates 1/1/2020	$ Chg from Present	% Chg from Present	Proposed Rates 1/1/2021	$ Chg from 1/1/2020	% Chg from 1/1/2020	Proposed Rates 1/1/2022	$ Chg from 1/1/2021	% Chg from 1/1/2021
Baseline Territory Valley P	76	$111.11	$114.96	$3.84	3.5%	$118.41	$3.45	3.0%	$121.90	$3.49	2.9%
Baseline Territory Desert R	58	$83.84	$86.73	$2.89	3.4%	$89.32	$2.60	3.0%	$91.95	$2.62	2.9%
Baseline Territory Valley S	61	$88.86	$91.92	$3.06	3.4%	$94.67	$2.75	3.0%	$97.45	$2.78	2.9%
Baseline Territory Coast T	53	$73.88	$76.40	$2.51	3.4%	$78.66	$2.26	3.0%	$80.94	$2.28	2.9%
Baseline Territory Coast V	62	$88.90	$91.96	$3.05	3.4%	$94.70	$2.74	3.0%	$97.47	$2.77	2.9%
Baseline Territory Desert W	53	$76.33	$78.96	$2.63	3.4%	$81.32	$2.36	3.0%	$83.70	$2.38	2.9%
Baseline Territory Hills X	65	$93.76	$96.99	$3.23	3.4%	$99.89	$2.90	3.0%	$102.81	$2.93	2.9%
Baseline Territory Desert Y	87	$125.06	$129.36	$4.30	3.4%	$133.22	$3.86	3.0%	$137.12	$3.90	2.9%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

10. PG&E Residential Gas Bill Impact Format: Seasonal

Gas Bill Impact: CARE, Summer

GAS BILL CHANGES	**SUMMER**												
	Avg. Mo. Therms per Cust	Present Rates 7/1/2018	Proposed Rates 1/1/2020	$ Chg from Present	% Chg from Present		Proposed Rates 1/1/2021	$ Chg from 1/1/2020	% Chg from 1/1/2020		Proposed Rates 1/1/2022	$ Chg from 1/1/2021	% Chg from 1/1/2021
CARE Average Bill													
Baseline Territory Valley P	20	$20.26	$21.11	$0.85	4.2%		$21.87	$0.77	3.6%		$22.64	$0.77	3.5%
Baseline Territory Desert R	19	$17.93	$18.70	$0.76	4.2%		$19.38	$0.68	3.7%		$20.07	$0.69	3.6%
Baseline Territory Valley S	19	$17.83	$18.59	$0.76	4.2%		$19.27	$0.68	3.7%		$19.96	$0.69	3.6%
Baseline Territory Coast T	26	$24.83	$25.82	$0.99	4.0%		$26.71	$0.89	3.4%		$27.60	$0.90	3.4%
Baseline Territory Coast V	30	$31.55	$32.79	$1.23	3.9%		$33.90	$1.11	3.4%		$35.02	$1.12	3.3%
Baseline Territory Desert W	20	$20.30	$21.15	$0.85	4.2%		$21.91	$0.76	3.6%		$22.68	$0.77	3.5%
Baseline Territory Hills X	21	$19.74	$20.56	$0.81	4.1%		$21.29	$0.73	3.6%		$22.03	$0.74	3.5%
Baseline Territory Desert Y	28	$28.37	$29.48	$1.11	3.9%		$30.49	$1.00	3.4%		$31.50	$1.01	3.3%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

11. PG&E Residential Gas Bill Impact Format: Seasonal

Gas Bill Impact: CARE, Winter

GAS BILL CHANGES	**WINTER**												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	Therms	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	39	$71.89	$74.31	$2.41	3.4%		$76.48	$2.17	2.9%		$78.67	$2.19	2.9%
Baseline Territory Desert R	33	$58.79	$60.76	$1.97	3.4%		$62.54	$1.78	2.9%		$64.33	$1.79	2.9%
Baseline Territory Valley S	34	$61.10	$63.15	$2.05	3.3%		$64.99	$1.84	2.9%		$66.85	$1.86	2.9%
Baseline Territory Coast T	33	$47.67	$49.24	$1.57	3.3%		$50.66	$1.41	2.9%		$52.08	$1.43	2.8%
Baseline Territory Coast V	41	$62.48	$64.57	$2.09	3.3%		$66.46	$1.88	2.9%		$68.36	$1.90	2.9%
Baseline Territory Desert W	34	$59.99	$62.01	$2.02	3.4%		$63.83	$1.82	2.9%		$65.68	$1.84	2.9%
Baseline Territory Hills X	33	$52.20	$53.92	$1.72	3.3%		$55.47	$1.55	2.9%		$57.04	$1.56	2.8%
Baseline Territory Desert Y	47	$81.25	$83.95	$2.70	3.3%		$86.39	$2.43	2.9%		$88.84	$2.46	2.8%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

12.PG&E Residential Electric Bill Impact: Annual Monthly Avg.

Electric Bill Impact: Non-CARE, Annual

ELECTRIC BILL CHANGES	ANNUAL										
	Avg. Mo.	Present	Proposed	$	%	Proposed	$	%	Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from	Rates	Chg from	Chg from	Rates	Chg from	Chg from
Non-CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present	1/1/2021	1/1/2020	1/1/2020	1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	518	$113.66	$122.39	$8.73	7.7%	$125.44	$3.05	2.5%	$128.82	$3.37	2.7%
Baseline Territory Coast Q	546	$128.52	$138.32	$9.80	7.6%	$141.75	$3.43	2.5%	$145.54	$3.79	2.7%
Baseline Territory Desert R	563	$126.15	$135.79	$9.64	7.6%	$139.16	$3.37	2.5%	$142.88	$3.72	2.7%
Baseline Territory Valley S	525	$116.77	$125.73	$8.95	7.7%	$128.86	$3.13	2.5%	$132.32	$3.46	2.7%
Baseline Territory Coast T	311	$65.70	$70.95	$5.25	8.0%	$72.78	$1.83	2.6%	$74.81	$2.03	2.8%
Baseline Territory Coast V	372	$79.05	$85.26	$6.21	7.9%	$87.44	$2.18	2.6%	$89.84	$2.40	2.7%
Baseline Territory Desert W	572	$128.66	$138.48	$9.82	7.6%	$141.92	$3.43	2.5%	$145.71	$3.79	2.7%
Baseline Territory Hills X	443	$97.33	$104.87	$7.54	7.7%	$107.51	$2.64	2.5%	$110.42	$2.91	2.7%
Baseline Territory Desert Y	408	$85.07	$91.72	$6.65	7.8%	$94.05	$2.33	2.5%	$96.62	$2.57	2.7%
Baseline Territory Desert Z	247	$48.49	$52.49	$4.00	8.2%	$53.88	$1.40	2.7%	$55.43	$1.55	2.9%

Illustrative rate and usage values from PG&E’s 2020 GRC Phase I

13.PG&E Residential Electric Bill Impact: Annual Monthly Avg.

Electric Bill Impact: CARE, Annual

ELECTRIC BILL CHANGES	ANNUAL												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	kWh	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	522	$70.55	$76.14	$5.60	7.9%		$78.10	$1.96	2.6%		$80.26	$2.16	2.8%
Baseline Territory Coast Q	591	$87.40	$94.22	$6.82	7.8%		$96.60	$2.39	2.5%		$99.24	$2.63	2.7%
Baseline Territory Desert R	571	$79.02	$85.23	$6.21	7.9%		$87.40	$2.17	2.6%		$89.80	$2.40	2.7%
Baseline Territory Valley S	527	$71.92	$77.62	$5.70	7.9%		$79.61	$2.00	2.6%		$81.81	$2.20	2.8%
Baseline Territory Coast T	301	$37.56	$40.76	$3.20	8.5%		$41.88	$1.12	2.8%		$43.12	$1.24	3.0%
Baseline Territory Coast V	351	$44.06	$47.73	$3.67	8.3%		$49.02	$1.29	2.7%		$50.43	$1.42	2.9%
Baseline Territory Desert W	582	$80.98	$87.33	$6.35	7.8%		$89.56	$2.23	2.5%		$92.01	$2.46	2.7%
Baseline Territory Hills X	392	$50.26	$54.38	$4.12	8.2%		$55.82	$1.44	2.7%		$57.42	$1.60	2.9%
Baseline Territory Desert Y	493	$67.13	$72.47	$5.35	8.0%		$74.35	$1.87	2.6%		$76.41	$2.07	2.8%
Baseline Territory Desert Z	282	$34.26	$37.22	$2.96	8.7%		$38.26	$1.04	2.8%		$39.40	$1.15	3.0%

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

14. PG&E Residential Gas Bill Impact: Annual Monthly Avg.

Gas Bill Impact: Non-CARE, Annual

Gas BILL CHANGES	ANNUAL										
	Avg. Mo.	Present	Proposed	$	%	Proposed	$	%	Proposed	$	%
	Therms	Rates	Rates	Chg from	Chg from	Rates	Chg from	Chg from	Rates	Chg from	Chg from
Non-CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present	1/1/2021	1/1/2020	1/1/2020	1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	45	$77.57	$80.33	$2.75	3.7%	$82.80	$2.48	3.2%	$85.30	$2.50	3.1%
Not Applicable											
Baseline Territory Desert R	34	$57.55	$59.59	$2.04	3.7%	$61.43	$1.84	3.3%	$63.29	$1.85	3.2%
Baseline Territory Valley S	36	$61.00	$63.16	$2.16	3.7%	$65.10	$1.95	3.3%	$67.07	$1.96	3.2%
Baseline Territory Coast T	37	$56.81	$58.81	$2.00	3.6%	$60.61	$1.80	3.2%	$62.42	$1.81	3.1%
Baseline Territory Coast V	44	$69.88	$72.36	$2.48	3.6%	$74.59	$2.22	3.1%	$76.83	$2.25	3.1%
Baseline Territory Desert W	32	$53.10	$54.99	$1.89	3.7%	$56.68	$1.70	3.3%	$58.40	$1.71	3.2%
Baseline Territory Hills X	41	$67.38	$69.77	$2.39	3.7%	$71.91	$2.14	3.2%	$74.07	$2.16	3.1%
Baseline Territory Desert Y	54	$89.76	$92.91	$3.15	3.6%	$95.75	$2.83	3.1%	$98.61	$2.86	3.1%
Not Applicable											

Illustrative rate and usage values from PG&E’s 2020 GRC Phase I

15. PG&E Residential Gas Bill Impact: Annual Monthly Avg.

Gas Bill Impact: Non-CARE, Annual

Gas BILL CHANGES	ANNUAL												
	Avg. Mo.	Present	Proposed	$	%		Proposed	$	%		Proposed	$	%
	Therms	Rates	Rates	Chg from	Chg from		Rates	Chg from	Chg from		Rates	Chg from	Chg from
CARE Average Bill	**per Cust**	7/1/2018	1/1/2020	Present	Present		1/1/2021	1/1/2020	1/1/2020		1/1/2022	1/1/2021	1/1/2021
Baseline Territory Valley P	39	$50.38	$52.14	$1.76	3.7%		$53.73	$1.59	3.2%		$55.32	$1.60	3.2%
Not Applicable													
Baseline Territory Desert R	33	$41.77	$43.24	$1.47	3.7%		$44.56	$1.32	3.2%		$45.89	$1.33	3.2%
Baseline Territory Valley S	34	$43.07	$44.58	$1.51	3.7%		$45.94	$1.36	3.2%		$47.31	$1.37	3.2%
Baseline Territory Coast T	33	$38.15	$39.48	$1.33	3.6%		$40.68	$1.19	3.1%		$41.88	$1.21	3.1%
Baseline Territory Coast V	41	$49.59	$51.33	$1.73	3.6%		$52.89	$1.56	3.1%		$54.47	$1.58	3.1%
Baseline Territory Desert W	34	$43.45	$44.99	$1.53	3.7%		$46.36	$1.38	3.2%		$47.76	$1.39	3.2%
Baseline Territory Hills X	33	$38.68	$40.02	$1.34	3.6%		$41.23	$1.21	3.2%		$42.45	$1.22	3.1%
Baseline Territory Desert Y	47	$59.22	$61.25	$2.04	3.6%		$63.10	$1.83	3.1%		$64.95	$1.86	3.0%
Not Applicable													

Illustrative rate and usage values from PG&E's 2020 GRC Phase I

14. Appendix B: Post-Workshop Comments

14.1 TURN Comments: October 14, 2020

14.2 IOU Comments: October 30, 2020

14.1 TURN Comments: October 14, 2020

Comments of The Utility Reform Network on Rate Case Plan Workshop #2

Oct. 14, 2020

The Utility Reform Network (TURN) offers the following comments on the topics covered during Rate Case Plan (RCP) Workshop #2, held on October 7, 2020. This workshop covered topics related to standardization in the presentation and processing of GRCs. The Commission's aim in requiring this workshop, among the others ordered in D.20-01-002, has been to promote "efficiencies and improvements in GRCs."[1]

1. Master Data Request

During the workshop, the IOUs offered six "guiding principles" regarding the Master Data Request (MDR) "in order to standardize and streamline" the MDR "to become more efficient and useful."[2] Five of the six "guiding principles" involve removing questions from each utility-specific MDR to eliminate duplicative or essentially redundant questions, questions that ask for information readily obtained from the utility's testimony and workpapers, and questions that are outdated, not used or apparently useful to the Public Advocates Office (Cal Advocates), irrelevant, or impossible to answer.[3] The IOUs also "agree that it would be beneficial to submit the responses to the Master Data Request no later than 30 days after the filing of the application."[4]

TURN expects that the recommendations offered by the IOUs will streamline their production of MDR responses in each GRC, and, by removing duplicative questions, might theoretically save intervenors some amount of time. However, the IOUs have not addressed any of the concerns that intervenors like TURN have expressed over the years regarding the MDR and how it could evolve to reduce the need for additional discovery from parties other than Cal Advocates.

For instance, in comments filed in R.13-11-006 in January 2014, TURN recommended that the MDR be updated to incorporate some of the standard data requests that TURN propounds in every GRC to reduce the need for discovery by TURN. TURN noted that other intervenors might likewise benefit from this accommodation.[5] Then in comments filed in R.13-11-006 in April 2018, TURN expressed support for a proposal from SCE to start meeting with a broader group of Commission staff, as well as TURN and other intervenors, to inform the MDR for each GRC "so that all parties have the opportunity to provide input and guidance on the data they are most interested in obtaining through the MDR."[6] TURN recommended the immediate extension of SCE's proposal to all IOU GRCs.[7]

Most recently, TURN provided feedback on the "Preliminary RCP Workshop Plan" prepared by Energy Division Staff in preparation for this workshop series. There TURN again

---

[1] D.20-01-002, pp. 56-57.
[2] Workshop #2 – IOU Presentation, Slide 4.
[3] *Id.*, Slides 5-6.
[4] *Id.*, Slide 6.
[5] TURN Comments on OIR, 1/15/14, p. 36 (responding to the Commission's question "Whether or not the NOI is retained, should the "master data request" be reviewed and possibly updated?").
[6] TURN Reply Comments on Staff Workshop Report, 4/19/18, pp. 8-9.
[7] *Id.*, p. 9.

highlighted the opportunity to reduce discovery in GRCs by incorporating some of TURN's routine GRC data requests into the MDR. TURN also recommended that the IOUs post non-confidential versions of the MDR on their GRC webpages with a clear index of topics so that all intervenors could benefit from the efficiencies intended by the MDR. Finally, TURN advocated a standard numbering system for MDR questions across utilities to facilitate ease of access.[8]

During Workshop #2, TURN offered the following four proposals, which incorporate TURN's earlier suggestions. These proposals are intended to make the MDR available and more useful to a broader range of GRC stakeholders and promote efficiencies in GRC processing by reducing the need for party-specific discovery and preventing duplication in data requests.

a. **A proposed MDR template should be circulated to regular GRC intervenors for possible expansion to include questions routinely asked by intervenors through discovery.**

b. **The MDR should be revised to include a standard index, table of contents, and high-level numbering system used consistently across utilities.** For instance, "Chapter 8" of the MDR could include A&G questions, with the understanding that some sub-topics would be applicable only to certain IOUs.

c. **The applicant IOU should post a public version of the MDR responses (including a table of contents or index) on its GRC webpage, where testimony and workpapers are provided, with instructions regarding how to request access to confidential responses.**

d. **The applicant IOU should send a notice to the GRC service list when the MDR responses are posted.**

TURN believes these recommendations would promote efficiencies in GRC processing in furtherance of the Commission's goals expressed in D.20-01-002.

2. Joint Comparison Exhibit

The IOUs proposed a standardized approach to organizing the Joint Comparison Exhibit (JCE) layout.[9] They also proposed a general timeline for preparing the JCE, which would have the JCE submitted "2-4 weeks after hearings."[10]

The IOUs' proposals will not impact the resources required by TURN (and presumably other parties) to prepare the JCE, which are significant. While the IOUs undertake the initial drafting effort – a substantial effort, no doubt – TURN must carefully review all entries and provide proposed edits for the IOU to incorporate. In addition to double-checking financial impacts, this review requires consideration of whether the utility has accurately and fairly summarized both TURN's position and its own position. TURN has on many occasions throughout the years flagged sections of the draft JCE that read more like the utility's brief than a neutral comparison of parties' positions. This detailed review occurs at the same time that

[8] TURN Feedback on Preliminary RCP Workshop Plan, 7/10/20.
[9] Workshop #2 – IOU Presentation, Slides 8-10.
[10] *Id.*, Slide 10.

TURN is preparing its opening brief and involves the very same people.

It is TURN's understanding that the JCE is prepared for the convenience of the ALJ(s) and assigned Commissioner, and perhaps Energy Division staff, rather than the parties to a GRC. However, in D.20-01-002, the Commission contemplated that the assigned Commissioner and ALJ might decide not to require parties to prepare a JCE at all in some cases.[11] Given the resources required of all parties to prepare a JCE, TURN encourages the consideration in each GRC of whether a JCE will meaningfully assist the assigned Commissioner and ALJ in preparing a decision. TURN notes that preparation of a more limited JCE, such as one that compares only the financial impacts of parties' positions without the position summaries, would reduce workload considerably for parties like TURN. At the same time, TURN fully supports the preparation of the JCE where the assigned Commissioner and ALJ(s) find it useful.

3. Testimony Chapters Order

In D.20-01-002, the Commission promoted the idea of a "standardized index" for GRC testimony. The Commission explained that "a standardized presentation of each applicant's request will assist the Commission as a whole to understand the issues in any given GRC."[12] Likewise, the Commission stated, "By presenting their testimony according to a common outline, and using consistent terminology and standard table formats, the utilities will ease the work of the Commission."[13]

At Workshop #2, the IOUs proposed no material changes in the way that each IOU orders and structures its rate case showing.[14] As TURN indicated at Workshop #2, TURN appreciates the Commission's desire for standardization but has learned to navigate the distinct (and dynamic) approaches taken by the IOUs in presenting their GRC testimony. TURN has no further comments at this time.

4. Phase 2 Scheduling & Filing

The IOUs proposed a schedule for processing PG&E's, SCE's, and SDG&E's GRC Phase 2s, PG&E's Gas Cost Allocation Proceedings (GCAPs), PG&E's GT&S Cost Allocation and Rate Design proceedings (CARDs), and the Sempra Utilities' Triennial Cost Allocation Proceedings (TCAPs).[15] TURN is continuing to evaluate the implications of the IOUs' proposal and may offer recommendations after considering the draft workshop report.

5. Presentation of Recorded Spending Data

a. Incorporation of Base Year +1 Recorded Spending Data

In D.20-01-002, the Commission identified a "standard approach to 'Base Year +1 data'" as an "important topic for future workshops" and directed stakeholders to "endeavor to reach

---

[11] D.20-01-002, p. 60.
[12] D.20-01-002, p. 60.
[13] *Id.*, pp. 60-61.
[14] Workshop #2 – IOU Presentation, Slides 15-16.
[15] Workshop #2 – IOU Presentation, Slides 29, 31.

consensus on a means of incorporating this data into every GRC on an agreed upon schedule."[16] The Commission discussed the benefits to its past GRC decisionmaking from having Base Year +1 (BY+1) data available and suggested that the incorporation of BY+1 data into the case "should be considered a standard milestone in every energy GRC."[17] Accordingly, the Commission directed Staff to include among the GRC "standardization" workshop topics the following:

> "Developing and recommending general ground rules regarding identification of the Base Year, as well as a common framework for incorporating updated 'Base Year +1' recorded data at a given stage of the GRC proceeding."[18]

Nonetheless, at Workshop #2 the IOUs proposed to retain the status quo approach to BY+1 recorded spending data. That is, the IOUs would make this data available by late Q1 (of BY+2) only upon request through the discovery process.[19]

TURN opposes this approach. It does nothing to increase efficiency in GRC processing, and it ignores the Commission's directive that parties strive to make the incorporation of BY+1 recorded data "a standard milestone in every energy GRC."

TURN discussed an alternative approach at Workshop #2, wherein the applicant IOU would serve an exhibit containing BY+1 recorded spending data by *no later than* March 1 of BY+2. The exhibit should include electronic Excel files (as is typically how BY+1 data is presented), as well as PDF versions.

While not ideal, TURN's proposed timeline would at least provide parties with an opportunity to use BY+1 data in briefing, which will occur in April and May in the new RCP schedule adopted in D.20-01-002.[20] Parties might also use BY+1 data during evidentiary hearings, which will occur between February 25 and March 15 according to the new schedule.[21] To facilitate the use of BY+1 data during briefing, the Commission would need to admit the BY+1 exhibit into the evidentiary record. This could either occur during evidentiary hearings or through a written ALJ ruling in March addressing the admission of BY+1 data into the record.

TURN recommends the following amendment to the new RCP schedule to standardize the incorporation of BY+1 data (*new events are in italics*):

[16] D.20-01-002, p. 61.
[17] D.20-01-002, pp. 61-62.
[18] D.20-01-002, pp. 69-70; Ordering Paragraph 5.
[19] Workshop #2 – IOU Presentation, Slide 39.
[20] Workshop #2 – IOU Presentation, Slide 40.
[21] *Id.*

Date	Days	Event
By February 25	~Day 285	Evidentiary hearings begin
Q1, By March 1	*~Day 290*	*Utility serves exhibit with BY+1 recorded spending data*
By March 15	*~Day 305*	*ALJ admits BY+1 recorded spending data exhibit into the record during evidentiary hearings or by written ruling*
By March 15	~Day 305	Evidentiary hearings end
By April 20	~Day 340	Briefs filed

b. Recorded Spending Data Included in GRC Application

TURN additionally offers feedback on the presentation of historical spending data included with the GRC application. TURN did not provide this feedback during the workshop but, upon further reflection, believes it will promote the Commission's objectives for Workshop #2.

The IOUs propose to provide 5 years of recorded data with their applications, including the Test Year minus 3 and 4 prior years. For an example, a GRC application filed in 2025 for Test Year 2027 would include recorded data for 2020-2024.[22] TURN supports this proposal and has a strong preference for the full five years of data to be provided (1) in the testimony, and (2) in a table that also includes the forecast. Some utilities provide the pre-base year historical data only in workpapers and separated from the forecast.

Second, TURN believes it would be useful for the applicant to include the authorized amount for the year in the historical series corresponding to the last test year. This would be the year prior to the base year in the new 4-year GRC cycle, according to the IOUs' proposal.[23] Given the Commission's attention to spending accountability in D.20-01-002, TURN submits that having this information in the same place as the applicant's forecast would support the efficient examination of the reasonableness of the IOU's test year forecast.

6. Bill Impact Calculation

The last topic addressed at Workshop #2 was the IOUs' proposed standard bill impact calculations for residential customers to be included with each GRC application.[24] The IOUs offered a thoughtful proposal, which TURN supports with two additions. TURN discussed each of these changes during Workshop #2.

a. The applicant IOU should present all of the proposed bill impacts on a service territory-wide basis, in addition to by climate zone.

[22] Workshop #2 – IOU Presentation, Slide 39.
[23] *See* Workshop #2 – IOU Presentation, Slide 38.
[24] *See* D.20-01-002, p. 67; Ordering Paragraph 6.

Presenting this information on a service territory-wide basis will facilitate comparisons between GRCs of the same utility (including past GRCs where bill impacts were not provided by climate zone) and across utilities. It will also simplify mass-market communications with utility customers, whether from the Commission or other GRC stakeholders.

b. The applicant IOU should present the long-term revenue requirement impact of its proposed GRC capital spending, covering at least 10 years of impacts.

This second addition captures the Commission's concern in D.20-01-002 about the "long-term impact of capital investments on customer rates."[25] Indeed, as some workshop participants acknowledged, depreciation and taxes can sometimes cause short-term negative impacts on revenue requirements, only to be followed by large increases in revenue requirements in later years. It is important for the Commission and stakeholders to have a clear understanding of how the IOU's proposed capital spending will impact revenue requirements beyond the initial years in the GRC cycle.

In other proceedings, the Commission has had the benefit of this type of showing by the utility in evaluating the reasonableness of proposed capital spending. TURN attaches an example of the type of showing we are recommending for GRCs that comes from SDG&E's Electric Vehicle-Grid Integration Pilot Program application, filed in 2014. See Appendix B of the attached testimony, providing the "Annual Revenue Requirement" from 2015 through 2037 as well as total revenue requirements associated with the proposed program. This exhibit illustrates why the Commission needs to understand the full costs that ratepayers will pay overtime for proposed GRC capital projects (first year annual revenue requirement impacts of less than $1 million jump to more than $10 million by the fourth year and total nearly $200 million for the full recovery period).

For purposes of an initial, standard GRC showing, TURN proposes that the utility provide at least 10 years of annual revenue requirement impacts from its proposed GRC capital spending. TURN recognizes that this time period will not cover the full recovery in rates from all capital spending. TURN may advocate a longer time period in the future.

c. The IOUs did not address GRC bill impacts in addition to all other pending rate change requests, as suggested by Staff.

Last but not least, TURN notes that the IOUs' proposal did not address the second part of the assignment suggested in Energy Division's Preliminary RCP Workshop Plan. Staff suggested that the IOUs would additionally submit sample bill impacts "showing the cumulative effect of the GRC rate change request with all other pending rate change requests." TURN agrees with Staff's preliminary determination that such bill impacts would be useful for the Commission and parties to have in reviewing the IOU's GRC proposals. TURN accordingly recommends that the IOUs amend their proposal to include a template for "cumulative" bill impacts (referring to the cumulative effect of all other pending rate change requests).

[25] D.20-01-002, p. 64.

ATTACHMENT

Example of Utility Showing on Long-Term Revenue Requirement Impacts from Proposed Capital Spending

Application No. A.14-04-____
Exhibit No.: ______
Witness: Jonathan B. Atun

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Approval of its Electric Vehicle-Grid Integration Pilot Program.	))))	Application No. 14-04-___ (Filed April 11, 2014)

PREPARED DIRECT TESTIMONY OF

JONATHAN B. ATUN

CHAPTER 4

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

April 11, 2014

#286657

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF

JONATHAN B. ATUN

CHAPTER 4

I. PURPOSE AND SUMMARY

The purpose of my testimony is to: (1) identify the costs associated with San Diego Gas & Electric Company's (SDG&E's) proposed Vehicle-Grid Integration (VGI) Pilot Program, (2) describe the methodology used by SDG&E in determining the revenue requirements for the VGI Pilot Program, and (3) identify the resulting annual revenue requirement. Since the VGI Pilot Program proposes services and capital costs above and beyond those authorized by the Commission in SDG&E's most recent general rate case (GRC),[1] all costs associated with the VGI Pilot Program are incremental, and thus additive to any currently authorized levels of revenue requirement.

II. VGI PILOT PROGRAM COSTS

A. Capital Costs

Table JBA-1 below identifies the capital costs[2] for the VGI Pilot Program, prior to adjustment for overhead and escalation factors.

Table JBA-1
Capital Costs
(excludes escalation and loaders; includes sales tax)

(in $000)	2015	2016	2017	2018	2019	2020 - 2037	Total
Engineering Design and Permitting	$ 143	$ 287	$ 574	$ 574	$ -	$ -	$ 1,578
New Electric Service	902	1,804	3,608	3,608	-	-	9,922
Transformer Installation	88	176	353	353	-	-	970
EVSE and Control Equipment Installation	3,739	7,478	14,957	14,957			41,132
Billing System Integration	1,475						1,475
Billing System Hardware	89	-	-	-	-	-	89
Total Capital Costs	$ 6,437	$ 9,746	$ 19,491	$ 19,491	$ -	$ -	$ 55,165

Differences due to rounding for Table JBA-1 and all other tables in Chapter IV

[1] Decision (D.)13-05-010.
[2] As provided by witness Randy Schimka in Chapter 2. Appendix A converts the per-installation costs provided by Mr. Schimka to the total capital costs in Table JBA-1.

B. Operation and Maintenance (O&M) Costs

Table JBA-2 below identifies the O&M costs[3] for the VGI Pilot Program, prior to any adjustment factors. O&M consists of ongoing services and replacement costs which will be provided by third party vendors (for the service, maintenance, and upkeep of the charging stations and software) and SDG&E (for sales and marketing, customer support, billing system integration, and pricing signals analysis).

Table JBA-2
O&M Costs
(excludes escalation and loaders; includes sales tax)

(in $000)	2015	2016	2017	2018	2019	2020 - 2037	Total
Charging Equipment Replacement	$ -	$ -	$ -	$ -	$ -	$ 22,982	$ 22,982
Access Control Fees	53	158	370	581	581	10,454	12,197
Transformer Installation O&M	10	20	39	39	-	-	108
SDG&E Internal Labor	275	275	275	275	90	1,620	2,810
Contract Labor	225	225	225	425	-	-	1,100
Customer Engagement Support	83	83	33	33	-	-	230
Total O&M Costs	$ 645	$ 761	$ 941	$ 1,353	$ 671	$ 35,056	$ 39,426

C. Adjustments to Capital and O&M Costs

1. Overhead Loaders

Overhead loaders are used to allocate undistributed company overhead costs across capital projects and O&M. Overhead costs are those activities and services that are associated with direct costs, such as payroll taxes and pension and benefits, or are costs that cannot be economically direct-charged, such as administrative and general overheads. Overhead loader values for the VGI Pilot Program adhere to the methodology proposed by the Federal Energy Regulatory Commission (FERC)[4] and were derived using the same methodology used in SDG&E's most recent GRC filing.

[3] As provided by witness Randy Schimka in Chapter 2. Appendix A converts the O&M costs provided by Mr. Schimka to the total O&M costs in Table JBA-2.
[4] FERC guidelines reference the Statement of Federal Financial Accounting Standards 4: Managerial Cost Accounting Standards and Concepts.

2. Escalation of Future Costs

Cost escalation factors are used to reflect the effect of inflation on SDG&E's costs. SDG&E's escalation costs were derived using 2013 Global Insight forecast indices. No escalation factors were applied to third-party vendor costs associated with ongoing O&M because SDG&E intends to enter into fixed-price contractual agreements with these vendors. SDG&E also assumes no change to the pricing of Electric Vehicle Supply Equipment (EVSE) component costs. This assumption is supported by current and historical charging station prices provided by Clipper Creek, Inc.[5]

Tables JBA-3 and JBA-4 show the capital and O&M costs adjusted for SDG&E overhead loaders and cost escalation.[6]

Table JBA-3
Capital Costs
(includes escalation, loaders, and sales tax)

(in $000)	2015	2016	2017	2018	2019	2020 - 2037	Total
Engineering Design and Permitting	$ 151	$ 302	$ 605	$ 605	$ -	$ -	$ 1,663
New Electric Service	951	1,902	3,804	3,804	-	-	10,460
Transformer Installation	187	382	782	804	-	-	2,155
EVSE and Control Equipment Installation	3,942	7,884	15,768	15,768	-	-	43,361
Billing System Integration	1,485	-	-	-	-	-	1,485
Billing System Hardware	94	-	-	-	-	-	94
Total Capital Costs	$ 6,810	$ 10,470	$ 20,958	$ 20,980	$ -	$ -	$ 59,218

[5] Clipper Creek, Inc. is a leading manufacturer of EVSE.
[6] No allowance for funds used during construction (AFUDC) is included, as payments will only be made when the VGI Pilot Program work is complete and placed in service.

Table JBA-4 O&M Costs (includes escalation, loaders, and sales tax)							
(in $000)	2015	2016	2017	2018	2019	2020 - 2037	Total
Charging Equipment Replacement	$ -	$ -	$ -	$ -	$ -	$ 23,195	$ 23,195
Access Control Fees	53	160	373	586	586	10,552	12,310
Transformer Installation O&M	23	47	96	98	-	-	264
SDG&E Internal Labor	508	519	531	544	182	4,083	6,367
Contract Labor	229	234	240	464	-	-	1,167
Customer Engagement Support	83	83	33	33	-	-	232
Total O&M Costs	$ 897	$ 1,043	$ 1,272	$ 1,725	$ 768	$ 37,830	$ 43,536

D. Total Costs

After updating the capital and O&M costs with the appropriate adjustment factors noted above, the total VGI Pilot Program costs for purposes of calculating the revenue requirement are shown in Table JBA-5 below.

Table JBA-5 Capital and O&M Costs (includes escalation, loaders, and sales taxes)							
(in $000)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020 - 2037**	**Total**
Capital	$ 6,810	$ 10,470	$ 20,958	$ 20,980	$ -	$ -	$ 59,218
O&M	$ 897	$ 1,043	$ 1,272	$ 1,725	$ 768	$ 37,830	$ 43,536
Total	$ 7,706	$ 11,513	$ 22,230	$ 22,706	$ 768	$ 37,830	$ 102,753

III. REVENUE REQUIREMENT

The revenue requirement represents the total dollars that need to be collected each year in order to cover the costs and returns associated with the VGI Pilot Program. Specifically, the components that make up the revenue requirement are: return of capital (via depreciation), O&M costs, debt and equity returns, federal and state taxes, franchise fees, and uncollectible revenue. The projected revenue requirements are broken out by component and presented in Appendix B. A more detailed description of the components of the revenue requirement is presented in the sections that follow.

A. Return of Capital

The return of capital is equal to annual book depreciation, which uses the straight-line remaining life method.[7] Consistent with the FERC Code of Federal Regulations, SDG&E assumes the following useful lives for each asset category as presented in Table JBA-6.

Table JBA-6
Capital - FERC Useful Life

Asset Category	FERC Useful Life (Years)
Kiosk, Pedestal, Chargers	19
New Electric Service to EVSE	50
Transformers & Install Costs	33
Billing System Integration	5
Design, Permits, & Meters	19
Servers & Hardware	5

B. O&M Costs

O&M costs represent the total costs required to ensure the ongoing successful operation of the VGI Pilot Program. O&M costs are included in the revenue requirement and treated as a pass-through item.

C. Return

The current authorized annual return components of the revenue requirement for the VGI Pilot Program consist of return on debt (5.00 percent), return on preferred stock (6.22 percent), and return on equity (10.30 percent).[8] These values are then weighted by their

[7] This method is consistent with Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals. The CPUC issued this standard practice in 1961 as a guide for determining proper depreciation accruals.
[8] As adopted in D.12-12-034.

authorized capital allocation percentages and multiplied by the average rate base[9] to determine the revenue requirement for each return component. The authorized[10] weighted returns are listed in Table JBA-7 below.

Table JBA-7
SDG&E Rate of Return (ROR) Calculation

	Capital Ratio %	Cost	Authorized Weighed Cost
Long-Term Debt	45.25%	5.00%	2.26%
Preferred Equity	2.75%	6.22%	0.17%
Common Equity	52.00%	10.30%	5.36%
	100.00%		7.79%

D. Tax

1. Property Tax

The annual property tax expense for the VGI Pilot Program is calculated by multiplying the period ending rate base by SDG&E's effective property tax rate of 1.328 percent.[11]

[9] Rate base represents the amount of capital on which shareholders are allowed to earn a return. The calculation of rate base for this filing is consistent with the methodology used in SDG&E's 2012 General Rate Case filing.
[10] As adopted in D.12-12-034.
[11] Consistent with previous filings, SDG&E's effective property tax rate is calculated by dividing the total property taxes due by county (per SDG&E property tax bills) by the total assessed value by county.

2. Federal and State Income Tax

a. Federal Income Tax

Federal income tax expense is calculated by multiplying federal Earnings Before Income Tax (EBIT)[12] by the current corporate federal income tax rate of 35 percent. In accordance with established Commission policy,[13] federal income taxes are computed on a normalized basis for utility ratemaking purposes.[14] An annual breakout of the federal tax component of the revenue requirement is provided in Appendix B.

b. State Income Tax

State income tax expense is calculated by multiplying state EBIT[15] by the current California Corporation Franchise Tax rate of 8.84 percent. State income taxes are not normalized, but instead are calculated on a flow-through basis.[16]

E. Franchise Fees and Uncollectibles

Franchise Fees and Uncollectibles (FF&U) are the final calculated components of the revenue requirement. Franchise fees cover the payments made to counties and incorporated cities pursuant to local ordinances granting a franchise to the company to place utility property in the public rights of way. Uncollectibles represent the estimated uncollectible expenses incurred by SDG&E. FF&U is calculated by multiplying the sum of all other

---

[12] For ratemaking purposes, federal EBIT is calculated as the sum of Common and Preferred Stock Returns minus prior year state taxes, multiplied by a tax gross-up factor. The tax gross-up factor is mathematically required to compute a pre-tax earnings number that, once taxes are applied, results in SDG&E's achievement of its authorized rate of return.

[13] *See* the direct testimony of Randall Rose, SDG&E General Rate Case proceeding (A.10-12-005).

[14] Normalization requires that any tax adjustments for deferred taxes (due to accelerated federal tax depreciation methods) are not included when calculating the annual required taxes due from ratepayers through the revenue requirement.

[15] For ratemaking purposes, state EBIT is calculated as the sum of Common and Preferred Stock Returns minus any deferred state income tax, multiplied by a tax gross-up factor. The tax gross-up factor is mathematically required to compute a pre-tax earnings number that, once taxes are applied, results in SDG&E's achievement of its authorized rate of return.

[16] Consistent with Commission policy, flow-through accounting treats temporary differences between recognition of expenses for book purposes and their tax return treatment as current adjustments to the revenue requirement.

revenue requirement components by the authorized multipliers[17] for franchise fees and uncollectibles.

IV. CONCLUSION

The final revenue requirement for the VGI Pilot Program, broken out by component, is summarized in Appendix B. This concludes my direct testimony.

[17] FF&U multipliers used for the VGI Pilot Program revenue requirement are consistent with those supported in D.13-05-010.

V. STATEMENT OF QUALIFICATIONS

My name is Jonathan Atun. My business address is 8330 Century Park Court, San Diego, California 92123. I am employed by SDG&E as the Financial and Strategic Analysis Manager. In my current role, I am responsible for managing, directing and coordinating the financial analysis of SDG&E projects.

I received a Bachelor of Science degree from San Diego State University in Business Administration with an emphasis in Accounting in 1988. I received a Master of Science degree from San Diego State University in Business Administration with an emphasis in Information Systems. I am licensed as a Certified Public Accountant by the State of California. I also hold a Certified Fraud Examiner Credential from the Association of Certified Fraud Examiners.

Prior to being employed by SDG&E, I was a financial analyst, forensic accountant and expert witness. My work involved analyzing and quantifying economic losses in business disputes and testifying in civil courts. I also provided general business consulting and services.

I have not previously testified before this Commission.

APPENDIX A

CAPITAL AND O&M BREAKDOWN

VGI Pilot Program Capital Breakdown

(in dollars)

Capital Category	Single Installation Cost	2015 x 50	2016 x 100	2017 x 200	2018 x 200	2019	2020 - 2037	Total x 550
Engineering Design and Permitting	2,869	$ 143,440	$ 286,880	$ 573,760	$ 573,760	$ -	$ -	**$ 1,577,840**
New Electric Service	18,040	902,000	1,804,000	3,608,000	3,608,000	-	-	**9,922,000**
Transformer Installation	1,764	88,175	176,350	352,700	352,700	-	-	**969,926**
EVSE and Control Equipment Installation								
Electric Vehicle Supply Equipment & Install	21,571							
Access Control Equipment & Installation	47,702							
ADA, Parking Modifications and Signage	5,512							
(Subtotal) EVSE and Control Equipment Installation	74,785	3,739,230	7,478,460	14,956,920	14,956,920	-	-	**41,131,530**
Billing System Integration								
Software Development	1,296,768							
VGI Phone and Web Applications	178,200							
(Subtotal) Billing System Integration*	1,474,968	1,474,968	-	-	-	-	-	**1,474,968**
Billing System Hardware*	89,100	89,100	-	-	-	-	-	**89,100**
Total Capital		**$6,436,913**	**$9,745,690**	**$19,491,380**	**$19,491,380**	**$ -**	**$ -**	**$55,165,364**

*One time cost

VGI Pilot Program O&M Breakdown

(in dollars)

O&M Category	Cost	Frequency	2015	2016	2017	2018	2019	2020 - 2037	Total
Charging Equipment Replacement									
Replacement EVSE Equipment	$21,571	x 550							
Replacement Access Control Equipment	14,702	x 550							
Replacement ADA Costs	5,512	x 550							
(Subtotal) Charging Equipment Replacement			$ -	$ -	$ -	$ -	$ -	$22,981,530	**$22,981,530**
Access Control Fees	1,056	annually/unit	52,800	158,400	369,600	580,800	580,800	10,454,400	**12,196,800**
Transformer Installation O&M	197		9,833	19,665	39,330	39,330	-	-	**108,158**
SDG&E Internal Labor									
Customer Engagment Internal labor	90,000	years: 1-4							
Billing System Integration Internal Labor	95,000	years: 1-4							
Rates/Dist. Circuit Modeling Labor	90,000	years: 1-23							
(Subtotal) SDG&E Internal Labor			275,000	275,000	275,000	275,000	90,000	1,620,000	**2,810,000**
Contract Labor									
Customer Engagment Contractor Labor	75,000	years: 1-4							
Customer Engagment Contractor Labor	75,000	years: 3-4							
Billing System Integration Contractor Labor	75,000	years: 1-2							
Cust. Support and Integration Svcs Contractor Labor	75,000	years: 1-4							
Evaluation of VGI Program Contract Labor	200,000	years: 4 only							
(Subtotal) Contract Labor			225,000	225,000	225,000	425,000	-	-	**1,100,000**
Customer Engagement Support									
Education and Outreach	200,000	total over 4 years							
Marketing Material	30,000	total over 4 years							
(Subtotal) Customer Engagement Support			82,500	82,500	32,500	32,500	-	-	**230,000**
Total O&M			**$ 645,133**	**$ 760,565**	**$ 941,430**	**$ 1,352,630**	**$ 670,800**	**$35,055,930**	**$39,426,488**

APPENDIX B

ANNUAL REVENUE REQUIREMENT

San Diego Gas & Electric
Vehicle Grid Integration

(in $000)	2015	2016	2017	2018	2019	2020
Depreciation:	278	796	1,517	2,479	2,960	2,802
O&M:	897	1,043	1,272	1,725	768	1,019
Return On Debt:	75	257	584	1,006	1,169	1,095
Return on Preferred:	6	19	44	76	88	83
Return on Common:	178	608	1,382	2,380	2,767	2,591
Property Taxes:	44	150	342	589	684	641
Federal Taxes:	(617)	632	952	1,532	1,708	1,493
State Taxes:	(163)	124	206	335	392	361
FF&U:	29	132	233	376	392	376
Revenue Requirement	$ 727	$ 3,761	$ 6,532	$10,497	$10,928	$10,461

(in $000)	2021	2022	2023	2024	2025	2026
Depreciation:	2,644	2,644	2,644	2,644	2,644	2,644
O&M:	1,691	3,030	4,722	5,429	5,188	4,525
Return On Debt:	1,028	964	901	841	781	722
Return on Preferred:	78	73	68	64	59	55
Return on Common:	2,433	2,281	2,134	1,990	1,849	1,709
Property Taxes:	602	564	528	492	457	422
Federal Taxes:	1,339	1,266	1,183	1,103	1,024	946
State Taxes:	336	334	329	324	318	311
FF&U:	379	417	468	482	460	424
Revenue Requirement	$ 10,529	$ 11,573	$12,977	$13,369	$12,781	$11,756

(in $000)	2027	2028	2029	2030	2031	2032
Depreciation:	2,644	2,644	2,644	2,644	2,644	2,644
O&M:	3,194	1,512	814	819	824	830
Return On Debt:	662	603	544	485	425	366
Return on Preferred:	50	46	41	37	32	28
Return on Common:	1,568	1,428	1,288	1,147	1,007	867
Property Taxes:	387	353	318	283	248	214
Federal Taxes:	867	789	710	632	553	474
State Taxes:	303	295	285	275	263	250
FF&U:	362	287	248	236	224	212
Revenue Requirement	$ 10,039	$ 7,956	$ 6,893	$ 6,558	$ 6,223	$ 5,885

(in $000)	2033	2034	2035	2036	2037
Depreciation:	2,644	2,536	2,213	1,567	705
O&M:	835	841	847	853	859
Return On Debt:	307	248	193	146	116
Return on Preferred:	23	19	15	11	9
Return on Common:	727	587	457	346	274
Property Taxes:	179	144	112	85	67
Federal Taxes:	395	310	225	149	101
State Taxes:	233	202	150	69	(27)
FF&U:	200	183	157	121	79
Revenue Requirement	$ 5,543	$ 5,071	$ 4,369	$ 3,346	$ 2,182

(in $000)	Remainder	Total
Depreciation:	6,989	59,218
O&M:	-	43,536
Return On Debt:	1,407	14,924
Return on Preferred:	106	1,128
Return on Common:	3,330	35,329
Property Taxes:	823	8,729
Federal Taxes:	1,877	19,644
State Taxes:	(115)	5,390
FF&U:	539	7,014
Revenue Requirement	$ 14,956	$194,910

APPENDIX C

GLOSSARY OF ACRONYMS AND DEFINED TERMS

ACRONYM	TERM
AFUDC	Allowance for funds used during construction
EBIT	Earnings before income tax
EVSE	Electric vehicle supply equipment
FF&U	Franchise fees and Uncollectibles
GRC	General rate case
O&M	Operations and maintenance
ROR	Rate of return
VGI	Vehicle-grid integration

14.2 Joint IOU Comments: October 30, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities	Rulemaking 13-11-006 (Filed November 14, 2013)

JOINT COMMENTS OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND PACIFIC GAS AND ELECTRIC COMPANY (U 39-M) ON RATE CASE PLAN WORKSHOP NUMBER 2

MARY A. GANDESBERY
PETER OUBORG

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2286
Facsimile: (415) 973-5520
E-Mail: peter.ouborg@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: October 30, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Develop a Risk-Based Decision Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities	Rulemaking 13-11-006 (Filed November 14, 2013)

**JOINT COMMENTS OF
SOUTHERN CALIFORNIA GAS COMPANY (U 904-G),
SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M),
SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) AND
PACIFIC GAS AND ELECTRIC COMPANY (U 39-M)
ON RATE CASE PLAN WORKSHOP NUMBER 2**

I. INTRODUCTION

In accordance with guidance provided by the Staff of the California Public Utilities Commission ("Commission"), the Investor-Owned Utilities ("IOUs") Southern California Gas Company ("SoCalGas"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE") and Pacific Gas and Electric Company ("PG&E") (collectively, the "IOUs") respectfully submit their joint comments regarding the October 7, 2020 General Rate Case Workshop ("Workshop 2"). Workshop 2 was conducted pursuant to the Commission's recent decision ("D") in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision").

Workshop 2 included six topics:

- Standardization of the Master Date Requests (MDR)
- Standardization of the Joint Comparison Exhibit (JCE)
- Standardization of Testimony Chapter Structure
- Phase 2 and Allocation Case Scheduling and Standardization
- Base Year and Recorded Spending Data
- Standardized Bill Impact Calculations

PG&E presented guiding principles and other proposals on behalf of the IOUs for all topics except for developing a standard testimony chapter structure. SCE presented the IOUs' position on the topic of structuring and standardizing testimony chapters. Participants from Energy Division, the Public Advocates Office ("Cal Advocates") and The Utility Reform Network ("TURN") actively participated in the workshop discussions.

Energy Division issued a draft workshop report, originally prepared by PG&E, for party comments on October 23, 2020. TURN provided additional comments on the issues addressed in Workshop 2 that were included in the draft workshop report at Appendix B.

Below, the IOUs provide a response to participants' comments at the Workshop as summarized in the draft report and TURN's post workshop comments.

II. DISCUSSION

A. Master Data Request

The IOUs explained at the workshop that the Master Data Request ("MDR") propounded by Cal Advocates in each GRC proceeding is burdensome for the utility staff, who are required to prepare responses simultaneously with the development of their GRC testimony and workpapers. The IOUs also noted that while Cal Advocates generally finds the information received to be useful, the responses to the MDR rarely appear in or are cited in the record of the proceeding; that approximately one-third of the questions were unnecessary since the topics were covered in testimony or workpapers; and that some questions requested data in a format that the IOUs did not have and could not provide. The IOUs made several proposals to streamline the MDR, including a new checklist, removal of duplicative questions regarding information in the IOUs' testimony or workpapers, and removal of questions that are not useful to Cal Advocates or are duplicative of other MDR questions.

Cal Advocates stressed that it prefers to have the ability to address the specific parameters of each rate case's MDR with the applicant, so that the questions asked of the utility and the responsive product provided by the utility are, to a degree, tailored to the specific preferences of Cal Advocates in that particular proceeding. The IOUs support Cal Advocates' inclinations with respect to standardization. The IOUs will continue to actively engage in any further discussions that may occur on this topic, whether at a subsequent workshop or in some other public forum.

TURN made several proposals for the MDR at the workshop that are explained more fully in its workshop comments.[1] While the IOUs support some of TURN's suggestions that are geared towards making the MDR more useful to the parties, others would increase, rather than decrease, the IOUs' burden to respond to the MDR and should not be adopted.

TURN proposes that the MDR be reorganized to include a standard index, table of contents, and numbering system consistent across the IOUs. The IOUs support this change if it is amenable to Cal Advocates. TURN also proposes that the public versions of the MDR responses be posted on the IOUs' websites, consistent with how the IOUs post their public testimony and workpapers, that instructions to request access to confidential responses be provided, and that an email be sent to the service list notifying them when the public version is available. Provided Cal Advocates agrees, the IOUs support making the non-confidential MDR content available to parties participating in a GRC proceeding, providing GRC parties with instructions and guidance for requesting confidential MDR responses, and notifying the service list when the MDR information is available, as this may reduce the number of data responses required in the proceeding if the other parties review the data responses before propounding additional, duplicative data requests.

The IOUs do not support, however, TURN's additional proposal that "[a] proposed MDR template should be circulated to regular GRC intervenors for possible expansion to include questions routinely asked by intervenors through discovery."[2] Adding to the MDR additional questions by intervenors prior to their review of testimony and workpapers would further increase the IOUs' burden to respond to the MDR, and would not necessarily add to the

---

[1] TURN, Appendix B,

[2] TURN, Appendix B, pp. 1-2.

information that is available to participants in the proceeding. The intervenors should instead review the IOUs' testimony and workpapers to determine whether further discovery is needed.

B. Joint Comparison Exhibit

The IOUs proposed changes to the Joint Comparison Exhibit ("JCE") to make the JCEs more uniform in the IOUs' GRCs for the convenience of the Commission and parties. Participants did not express concerns with the IOUs' proposals at the workshop. TURN's workshop comments indicate that while the IOUs take the laboring oar by initially drafting the JCEs for all of the parties, it is still burdensome for the other parties to review and edit the JCEs.

To address this burden and materially reduce the size of the JCEs, TURN suggests that the JCEs could be limited to the forecasts for the various programs and not include a narrative description of the parties' positions.[3] The IOUs support this change and agree that it would reduce the burden of preparing the JCE for all concerned. Alternatively, the IOUs would support an approach where the JCE contains citations to the place(s) in the record where each party has set forth its position, but the JCE does not add any narrative description of such position. Moreover, within the docket of any individual GRC, if the Administrative Law Judges or the Assigned Commissioner state that the particular issues or contours of the case warrant a reinstatement of the narrative description of parties' positions with respect to all or some portion of the case, the IOU can take the lead in developing the desired material, for that particular proceeding.

C. Testimony Chapters Order

The IOUs' presentation indicated that it would be difficult to standardize the IOUs' testimony since differences are found in each of the IOUs' respective organizational structures, accounting and financial systems, and other key elements. None of the workshop participants indicated that a problem actually exists with the current, non-standardized approach. TURN also helpfully stated in its workshop comments that it "has learned to navigate the distinct (and

---

[3] TURN, Appendix B, p. 3.

dynamic) approaches taken by the IOUs in presenting their testimony."[4] The IOUs do not believe that further exploration of this topic would be useful or productive.

D. Phase 2 Scheduling and Filing

The IOUs presented their proposal for the timing and content of future rate design proceedings, including the IOUs' GRC phase 2 proceedings, PG&E's next Gas Cost Allocation Proceeding ("GCAP"), PG&E's Gas Transmission and Storage ("GT&S") Cost Allocation and Rate Design ("CARD") proceeding, and SDG&E/SoCalGas' Triennial Cost Proceeding (TCAP). The IOU presentation included the following proposals:

- PGE's next GRC Phase 2 to be filed in summer 2024 and every 4 years subsequently
- PG&E's next GCAP to be filed within 90 Days of GT&S CARD decision
  - PG&E will file its GT&S CARD proceeding within 75 days of its 2023 GRC Phase 1 application
- SDG&E/SoCalGas's next Cost Allocation Proceeding to be filed in the third quarter of 2023 and future cost allocation proceedings to occur every four years, rather than every three
- No changes to SCE's filing schedule

While there were questions and discussions about the IOUs' proposals, none of the parties proposed an alternative schedule. In its written comments, TURN noted that it is continuing to evaluate the IOUs' proposal and may offer recommendations after considering the draft workshop report.[5]

Energy Division requested more information from the IOUs on what the consequences would be if the Commission did not approve PG&E's requests related to timing of its GRC Phase 2 application, GCAP filing, and CARD filing, and if the Commission did not approve Sempra's request related to timing of its next TCAP filing. Energy Division also asked how the IOUs propose to effectuate their recommendations. The following sections address these questions for PG&E and for SDG&E/SoCalGas.

---

[4] TURN, Appendix B, p. 3.

[5] TURN, Appendix B, p. 3.

1. PG&E's GRC Phase 2, GCAP, GT&S CARD

While PG&E has not been able to identify any tangible benefits to not implementing its timing proposals, PG&E notes the following identifiable consequences:

1. Rejecting the proposed IOU scheduling would permanently disconnect and distance GT&S ratemaking from implementation of GT&S functional revenue requirement changes in the GRC Phase 1, ending 22 years of simultaneous determination for the California gas marketplace and participants in PG&E's rate cases.

2. Rejecting the proposed IOU scheduling would cause a transitional five-year gap for both the PG&E GRC Phase 2 and GCAP versus the four-year rate case plan cycle in a time of dynamic but unknown changes in energy usage and pace of electrification across PG&E's service territory and across customer classes.

3. Rejecting the proposed IOU scheduling would be an inefficient use of the four-year rate case period for not only PG&E staff, but for CPUC Energy Division, Cal Advocates, and gas ratemaking intervenors, with Sempra's TCAP and PG&E's GCAP overlapping, and PG&E's GCAP litigation period overlapping with PG&E's GRC Phase 2 application development.

PG&E also notes that while its GRC Phase 2 scheduling proposal does not follow the 90-day traditional filing after its GRC Phase 1, its proposal to instead file the GRC Phase 2 in the summer prior to the filing of its GRC Phase 1 does not cause an overlap conflict with either SCE's or SoCalGas/SDG&E's GRC Phase 2 case schedule.

PG&E has prepared an extended graphic of the case schedules to illustrate the consequences of adopting the IOUs' near term scheduling proposals in transition, but then having PG&E move back to filing its GRC Phase 2 ninety days after filing its 2031 GRC Phase 1 and PG&E's GCAP including GT&S ratemaking beginning with its 2026 application, which is attached to these comments as Attachment 1. If parties can identify tangible benefits that increase overall efficiency of the allocation case from a schedule other than that proposed jointly by the IOUs, the IOUs would consider those comments. Regarding proposal implementation, as

PG&E stated in the workshop, there are other forums PG&E could use to implement the GCAP proposal, including filing a Petition for Modification or a Request for Extension. PG&E notes that a utility can file a CARD proceeding of its own accord. For GRC Phase 2 filings, PG&E is requesting Commission permission to change the filing date. PG&E also noted in the workshop that the IOUs would make a proposal for how to implement recommendations following the completion of all four workshops.

2. SDG&E/SoCalGas' TCAP

SoCalGas and SDG&E currently submit TCAPs, generally the gas equivalent of a GRC Phase 2 application for electric utilities, addressing rate design and demand determinant issues, every three years. Given the modification to SoCalGas' and SDG&E's rate case cycle and the commensurate change to SDG&E's electric GRC Phase 2 application, SoCalGas and SDG&E considered at the workshop likewise moving their cost allocation proceeding to occur every four years, rather than every three. SoCalGas and SDG&E also discussed the possibility of seeking to file their next cost allocation proceeding in Q3 2023, rather than Q3 2021, to align with the new rate case schedule and the GRC Phase 2 standard of making a cost allocation showing after submitting the rate case. This schedule proposal would avoid substantial scheduling overlap with the Track 2 (long-term natural gas policy and planning) schedule of the gas system reliability and planning rulemaking (R.20-01-007). Additionally, this schedule proposal would avoid scheduling overlap with PG&E's gas allocation cases, which would be an inefficient use of Energy Division, Cal Advocates, and other parties' ability to effectively and efficiently participate in the various proceedings.

CPUC staff inquired at the workshop as to how SoCalGas and SDG&E might effectuate this change. CPUC D.09-11-006 adopted a joint motion for adoption of settlement agreement in A.08-02-001, SoCalGas' and SDG&E's then-pending Biennial Cost Allocation Proceeding (BCAP). One of the terms adopted by that settlement agreement was to move cost allocation proceedings to occur every three years rather than every two years. Consistent with D.09-11-006, SoCalGas and SDG&E filed their 2020 TCAP application, A.18-07-024, for rates effective

January 1, 2020 through December 31, 2022. D.20-02-045 addressed all open issues in that proceeding and approved a cost allocation methodology for the three-year 2020 TCAP period.

SoCalGas and SDG&E are still analyzing the appropriate next steps for moving to a four-year cost allocation proceeding cycle. At this time, should SoCalGas and SDG&E seek to move to a four-year cost allocation proceeding cycle, one likely procedural path would be to file a Petition for Modification of D.20-02-045 to clarify that the current TCAP cycle will extend two addition years – through December 31, 2024. Consistent with this procedural path, when SoCalGas and SDG&E file their next TCAP application in Q3 2023, they would also include testimony seeking to modify their tariffs to memorialize a four-year cost allocation cycle moving forward. SoCalGas and SDG&E will confer with CPUC staff before filing such a petition should SoCalGas and SDG&E seek this procedural path.

E. Recorded Spending Data

1. Base Year and Recorded Year Spending Data

The IOUs and workshop participants agreed that the base year for a GRC test year should continue to be the recorded year spending for the year preceding the filing of the application. Participants also discussed a desire for the IOUs to produce the recorded year data for the year the application is filed, referred to as base year + 1 data. The participants acknowledged that the new rate case plan schedule, which includes evidentiary hearings from February 25 to March 15 precludes the parties from using this data in their written testimony.

TURN proposes that the IOUs produce the data by March 1 during evidentiary hearings so that it can be admitted into the record of the proceeding.[6] The IOUs discussed how producing the recorded data by March 1 would be difficult, given constraints including the U.S. Securities Exchange Commission (SEC)-regulated earnings call, the need to analyze the data and convert it to a format consistent with what is presented in the GRC, and the need to check the data for accuracy for it to be useful in the proceeding. In addition, the IOUs are required to file a Risk

[6] TURN, Appendix B, pp. 4-5.

Spending Accountability Report (RSAR) by March 31, which requires the same financial data and further constrains the IOUs' resources.

The IOUs are examining their internal processes to try and produce the base year + 1 data as early as possible to accommodate TURN's request to "provide parties with an opportunity to use BY+1 data in briefing"[7] while managing the practical constraints discussed in the workshop and noted above. While the IOUs cannot commit to meeting the March 1 date, they can commit to providing the data by March 31, and will endeavor to try to provide the data earlier. The IOUs also note that the adopted revised GRC application filing schedule sets a milestone for opening briefs to be filed by April 20.[8] If base year + 1 data was provided on March 31, parties would still have 20 days to incorporate the data into their briefs. Finally, the IOUs suggest that the base year + 1 recorded spending data be made available as part of the regular post-hearing update testimony. In this way, parties could ask the witness sponsoring the data questions about it, if necessary, at the update hearing.

2. Recorded Spending Data in Testimony

TURN's workshop comments provide two additional proposals regarding presentation of forecast and spending data in the IOUs' testimony.

First TURN proposes that the IOUs' testimony include a table with five years of recorded data and its test year forecast. The IOUs note this data is already made available to the Commission and intervenors in testimony and/or workpapers in the format requested by TURN.[9]

Second, TURN proposes that the IOUs "include the authorized amount for the year in the historical series corresponding to the last test year. This would be the year prior to the base year in the new 4-year GRC cycle, according to the IOUs' proposal."[10] The IOUs do not agree to this

[7] TURN, Appendix B, p. 4.

[8] D.20-01-002 at p. 49

[9] In TURN comments (Appendix B, p. 5), TURN incorrectly stated that some utilities provide the pre-base year historical data separated from the forecast.

[10] TURN, Appendix B, p. 5.

proposal. The prior authorized amount, which is available to TURN in the spending accountability report, would be based on a forecast from the year preceding the filing of the prior GRC application. As such, the IOUs do not think this data would aid in the resolution of the reasonableness of the current forecast. However, if TURN disagrees, it can access the data regarding the prior authorized amounts and use it in its testimony. It should not however, be required to be included in the IOUs' testimony.

F. Bill Impact Calculations

The IOUs' workshop proposal addressed the following requirement in Ordering Paragraph 6 of D.20-01-002:

> 6. As a compliance item in this docket, Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company shall develop bill impact calculations for residential customers in the applicant's service territory, differentiated by usage in each climate zone, or other means as may be directed by the Commission or by the Director of the Energy Division, to be included in every future GRC application. The utilities shall present their standardized calculations for discussion at the workshop or workshops facilitated by the Energy Division, in consultation with the Safety and Enforcement Division, as needed, pursuant to Ordering Paragraph 5 of this decision.

At the workshop, Energy Division staff requested to label the bill impact tables to clarify they refer to bundled customers, provide a version for all-electric customers, and provide a map of the baseline areas so that a customer could visually identify which climate zone applies to them. The IOUs agree that these would be constructive improvements and will implement these changes.

TURN proposed two additional changes to the IOUs' presentation regarding bill impacts calculations at the workshop, which it further addressed in its comments. It also added a third proposal, which was not raised at the workshop.

First, TURN suggests the IOUs present all of the proposed bill impacts on a service territory-wide basis in addition to climate zone.[11] It asserts that this type of information would facilitate comparison between rate cases and among the utilities " and simplify mass-market communications with utility customers whether from the Commission or other stakeholders."

The IOUs agree with this proposal.

Second, TURN asserted during the workshop that the plain meaning of D.20-01-002 requires ongoing monitoring of the long-term impacts of capital investments on customer rates and proposed that the IOUs model bill impacts for the first 10 years, followed by providing a calculation for every 5-10 years after the first 10 years. In its written comments TURN moderated its position compared to what was stated at the workshop and proposed that the IOUs "provide at least 10 years of annual revenue requirement impacts from its proposed GRC capital spending"[12] to provide better visibility into the long-term impact of the IOUs' capital spending, but did not specifically request more than 10 years, stating that TURN may advocate a longer time period in the future.

Contrary to its assertions about the plain meaning of D.20-01-002, TURN's request is not supported by any Commission decision or guidance. TURN's written comments provide a citation to a section of D.20-01-002 that discusses formula-based attrition year revenue requirements and concerns about such an approach to cost escalation putting capital expenditures on "autopilot."[13] This is a separate topic that was covered in Rate Case Plan Workshop 1. The discussion of incorporating standardized bill impact calculations into every GRC application in D.20-01-002 does not support TURN's request.[14]

In addition, TURN's request would place a significant burden on the IOUs to provide information that would be inaccurate and of dubious value. Providing calculations beyond the

---

[11] TURN, Appendix B, p. 5.

[12] TURN, Appendix B, p. 6.

[13] TURN, Appendix B, p. 6, citing D.20-01-002, p. 64.

[14] D.20-01-002, pp. 67, 70, 78, 79

attrition years of a GRC application would involve providing information that is not informed by changes to customer and sales forecasts and revenue requirements. These calculations would be incomplete and would provide customers with inaccurate information.[15] The IOUs believe that, with the changes proposed by Energy Division and TURN that the IOUs have agreed to, the IOUs will follow a robust approach that fulfills the Commission's requirements by providing standardized bill impact calculations for residential customers, by climate zone annually and seasonally and on a service-territory-wide basis, with supporting maps, for CARE and non-CARE customers, for basic baseline customers and all-electric customers, and for all attrition years.

Finally, TURN's comments address an additional issue regarding bill impact calculations that was ***not*** part of Workshop 2 and is ***not*** a topic identified for workshops in the RCP decision. TURN states that Energy Division's preliminary – but not final – agenda for Workshop 2 included a subject of whether the IOUs should submit bill impacts "showing the cumulative effect of the GRC rate change request with all other pending rate change requests."[16] This was not on the final agenda for the workshop and there was no discussion of this topic.

Aggregating outstanding rate increases for the purpose of determining rates or rate affordability is not in the scope of these workshops. That issue is better examined by the Commission as part of the OIR *to Establish a Framework and Processes for Assessing the Affordability of Utility Service*, R. 18-07-006. The Decision in Phase 1 of that proceeding, D.20-07-032, notes (1) several parties and Commission staff desired a framework to comprehensively analyze the cumulative impact of rate requests across proceedings, (2) a rate and bill tracker tool is under development that will facilitate tracking of costs, rates, and bill impacts and may meet

[15] In some proceedings outside of the GRC, some utilities have in the past provided revenue requirements for a longer duration because revenue requirements for these projects were independent of the GRC term at the onset. However, once the revenue requirement associated with the projects are incorporated into a subsequent GRC application, the revenue requirements presented for these projects are limited to the duration of GRC term. TURN's proposal would necessitate a revenue requirement projection far beyond the term of a GRC cycle.

[16] TURN, Appendix B, p. 6.

the aforementioned desire, and (3) unresolved issues about how that rate and bill tracker tool will be used will likely be addressed in a further phase of the Affordability proceeding.[17] Additionally, any such cumulative impact showing in the GRC Phase 1 filing could quickly be overcome by events, unlike the aforementioned rate and bill tracker tool as requested by Energy Division. The IOUs do not believe the Commission should include the issue in this workshop as it does not appear ripe for implementation or intended by the Commission to be addressed in these workshops.

III. CONCLUSION

The IOUs appreciate this opportunity to present in Workshop 2 and to provide written comments. The IOUs look forward to further discussions with the parties regarding efficiencies that can be achieved in the GRC proceedings.

Respectfully Submitted on behalf of the Investor-Owned Utilities,

By: */s/ Peter Ouborg*
PETER OUBORG

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-2286
Facsimile: (415) 973-5520
E-Mail: peter.ouborg@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

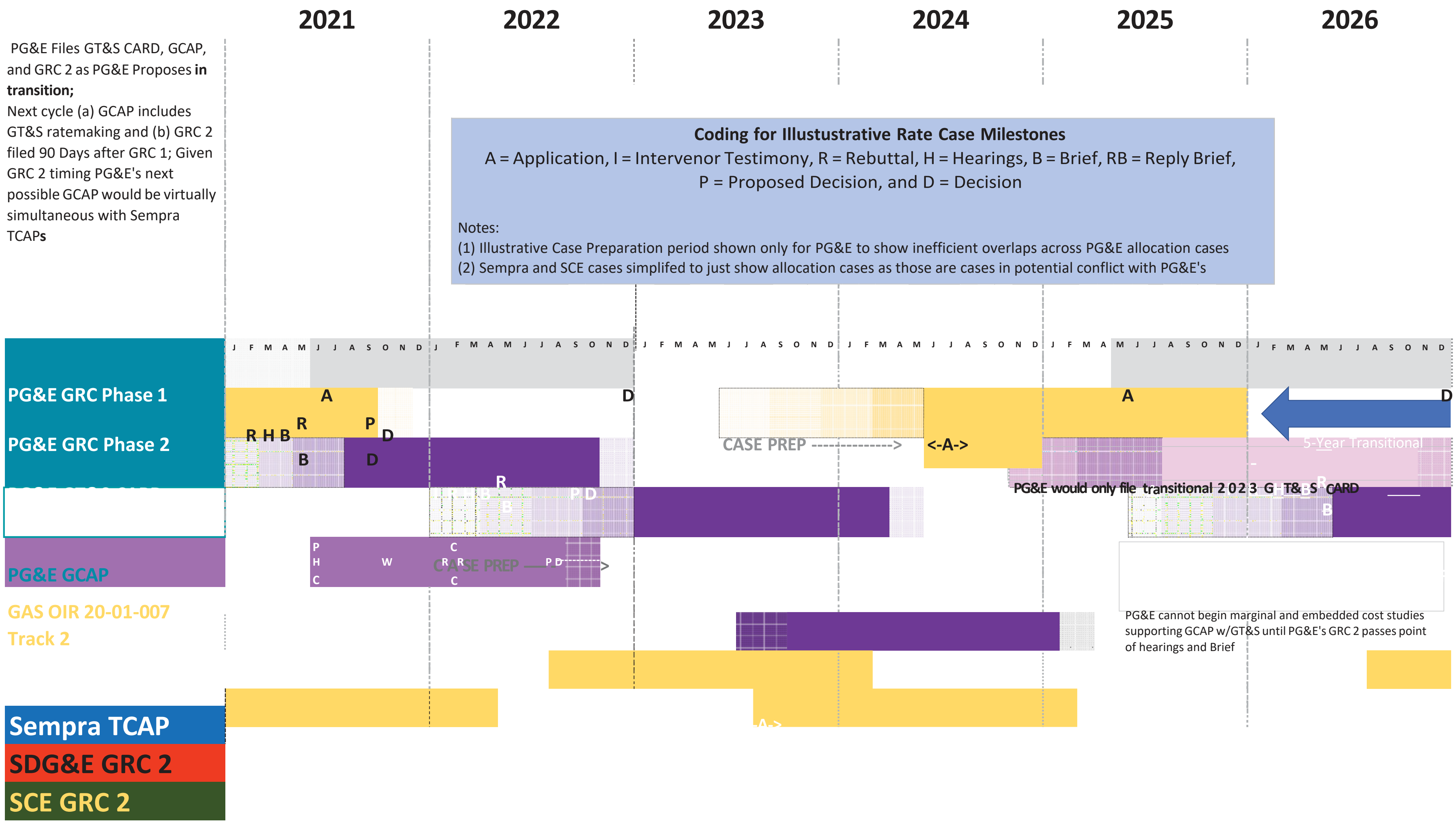
Dated: October 30, 2020

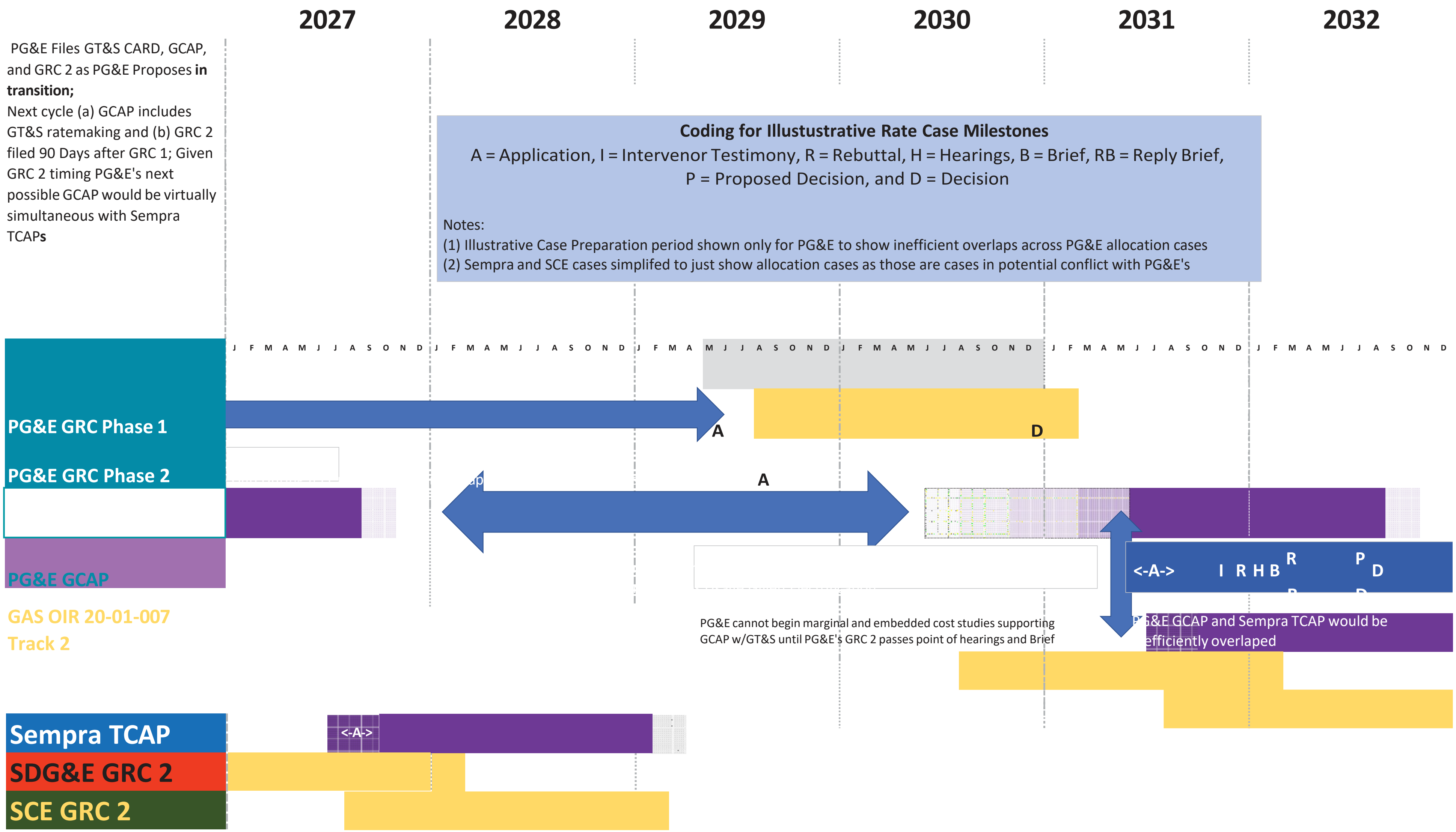
[17] D.20.07-032, pp. 70-74. Cal Advocates filed a motion to amend the scope of the June 9, 2020 scoping memo issued in the Affordability proceeding to ensure that the second phase of that proceeding will consider how the rate and bill tracker tool can be used for ongoing support of Commission work. The Third Amended Scoping Memo and Ruling issued on October 21, 2020 in R.18-07-006 adopts the issue requested by Cal Advocates.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT 1

Attachment 1: Alternative Scenario where Near-Term IOU Proposals are Adopted but Long-Term IOU Proposals are Not Adopted




2027
2028
2029
2030
2031
2032
PG&E Files GT&S CARD, GCAP, and GRC 2 as PG&E Proposes **in transition;**
Next cycle (a) GCAP includes GT&S ratemaking and (b) GRC 2 filed 90 Days after GRC 1; Given GRC 2 timing PG&E's next possible GCAP would be virtually simultaneous with Sempra TCAPs
Coding for Illustustrative Rate Case Milestones
A = Application, I = Intervenor Testimony, R = Rebuttal, H = Hearings, B = Brief, RB = Reply Brief,
P = Proposed Decision, and D = Decision
Notes:
(1) Illustrative Case Preparation period shown only for PG&E to show inefficient overlaps across PG&E allocation cases
(2) Sempra and SCE cases simplifed to just show allocation cases as those are cases in potential conflict with PG&E's
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
PG&E GRC Phase 1
A
D
PG&E GRC Phase 2
A
PG&E GCAP
<-A->
I R H B
R
P
D
GAS OIR 20-01-007
Track 2
PG&E cannot begin marginal and embedded cost studies supporting GCAP w/GT&S until PG&E's GRC 2 passes point of hearings and Brief
PG&E GCAP and Sempra TCAP would be efficiently overlaped
Sempra TCAP
<-A->
SDG&E GRC 2
SCE GRC 2

GENERAL RATE CASE PLAN WORKSHOP #3 REPORT

Uniformity in Results of Operations Model

Table of Contents

1. Executive Summary

On November 19, 2020, the California Public Utilities Commission's (CPUC) Energy Division (ED) hosted the third in a series of workshops to explore standardizing the organization and format of General Rate Case (GRC) filings for the large California energy utilities. The workshops were ordered in Decision (D.) 20-01-002, which modified the Commission's rate case plan (RCP) for the large energy utilities. The objective of the workshops is to further explore and develop proposals to streamline the GRC proceeding process. The scope of the third workshop involved exploring reasonable ways to make the Results of Operations (RO) models for the four large California utilities more uniform and user-friendly.

In addition to ED staff, identified attendees at the workshop included the five utilities - Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), Bear Valley Electric - and The Utility Reform Network (TURN) and the Public Advocates Office (Cal Advocates).

The workshop scope included five topics, followed by open discussion:

- Introduction to RO Model
- Standard Format for Summary of Earnings
- User-Friendly Interface
- Uniform RO Model Format & Structure
- Working Relationship with Administrative Law Judge & Energy Division

On behalf of the joint investor-owned utilities (PG&E, SCE, SDG&E, and SoCalGas; collectively "IOUs"), SCE led the presentation for all topics except for introductory remarks and a portion of the topic on Working Relationship with Administrative Law Judge (ALJ) & Energy Division. ED, Cal Advocates, and TURN all posed questions during the workshop. Below is a high-level summary of the workshop discussion:

- **Introduction to RO Model**: SCE provided an introductory overview on what the RO model is, what it is designed to accomplish, and how the elements of the model work together. The presentation was designed to be a straightforward, high level explanation geared toward an audience with limited RO model experience. SCE explained that each utility's model is a tool to calculate a utility's revenue requirement based on the Operations and Maintenance (O&M) and capital forecast, subject to any input adjustments by the model user. The IOUs have and continue to strive to ensure that their models meet three standards to help streamline GRC proceedings: simplification, transparency, and user-friendliness. SCE highlighted the major functions a user should be able to perform with the model and discussed the standard features in each utility's model.
- **Standard Format for Summary of Earnings**: The Summary of Earnings (SoE) refers to a table containing the components of the utility's revenue requirements such as expenses, taxes, and return on rate base. SCE noted that each utility's SoE contains the same foundational principles, with each aligned toward each utility's specific business operations, accounting, and financial systems. Thus, there are some differences among the IOUs, which SCE then highlighted. SCE also discussed some of the presentation and formatting differences among the models, but noted that they are reasonable and appropriate. Nonetheless, the IOUs are committed to identifying and exploring opportunities for future alignment in these areas.

- **User-Friendly Interface**: To enable a user without extensive RO modeling training to enter inputs into the model to calculate the revenue requirement. Each utility's RO model is uniquely standardized to help users navigate and understand what inputs can be changed and where the results of those changes can be located. Each model uses color coding, standard output tables, and has a standardization for file names to assist with this. SCE shared examples from each model and noted that while there is a slight variation in interfaces, all contain the same format, content, and structure to guide the user to make needed changes. The IOUs are committed to exploring further alignment on standardization on color coding, while remaining sensitive to the fact that each is customized to align with the individual business needs of each utility.
- **Uniform RO Model Format & Structure**: To be more consistent across the utilities and easier for the Commission and others outside the utilities to understand. Each RO model shares similar "DNA," in that the foundational structures are consistent across IOUs and follow very similar processes for sharing and educating users on the model. SCE shared a simple visualization of how data flows through the model, and then presented data flow diagrams for each utility. There was also discussion on the data processing sequence within each model.
- **Working Relationship with ALJ & Energy Division**: ED staff began the discussion by sharing the RO modeling process from the CPUC's vantage point. ED supports the Administrative Law Judge (ALJ) in a GRC by ensuring that the ALJ's Proposed Decision (PD) contains accurate information. The CPUC typically executes a non-disclosure agreement (NDA) with one or more utility RO model experts to assist in this process. SCE then discussed how the NDA is a "black box" in that no one external or internal to the utility, other than the individuals under the NDA, have any knowledge of what is discussed or performed. SCE proposed to continue this process, with some modifications to bring a greater standardization of overall process to GRCs when a utility's RO model expert provides assistance as requested by ED or the GRC ALJ. SCE also proposed that IOUs to be able to remotely perform this function.

A draft version of this workshop report was circulated for comment on December 7, 2020. The IOUs submitted their joint comments on December 14, which summarized points made during the workshop and responded to some of the comments made during the workshop. No other parties submitted post-workshop comments.

2. Introduction

On November 19, 2020, ED hosted the third in a series of workshops to explore opportunities for greater uniformity in the RO models that have been developed by the large California energy utilities for GRC filings. The large energy utilities are PG&E, SCE, SDG&E, and SoCalGas. The workshops were ordered in D.20-01-002, which modified the Commission's RCP for energy utilities. The objective of the workshops is to further explore ideas to standardize GRC filings and streamline the process in order to increase the efficiency of GRC proceedings. The scope of the third workshop was to explore ways to make the RO models of the four utilities more uniform and user-friendly, specifically in regards to developing 1) a standard format for the SoE, 2) a user-friendly input interface, 3) a uniform RO model format or structure, and 4) a single approach to IOUs' working relationship with the ALJ and ED staff. The workshop was facilitated by ED with support from SCE.

3. Background

On January 16, 2020, the Commission issued D.20-01-002 (the "Decision Modifying the Commission's Rate Case Plan for Energy Utilities" in Rulemaking (R.) 13-11-006). D.20-01-002 adopted changes to the Rate Case Plan for large California energy utilities to enable the Commission to conduct GRC proceedings more efficiently, including modifications to the GRC procedural schedule and extending the GRC cycle for each utility from three years to four years. R.13-11-006 was closed upon the CPUC adoption of D.20-01-002.

The RCP decision also ordered a series of workshops to explore and develop proposals to increase the efficiency of GRC proceedings. The basic purpose of the series of the workshops is to see if various matters common to all GRCs can be redesigned and consistently applied to make the proceedings more efficient for the Commissions and parties alike. Based on the number of workshop topics, ED identified four workshops and invited parties to provide feedback on the scope of each workshop:

1. Workshop No. 1 - Stipulated Terms / Rebuttable Presumptions / Standardized Attrition Year Ratemaking – September 4, 2020
2. Workshop No. 2 - Standardization of GRC Filings – October 7, 2020
3. Workshop No. 3 - Results of Operations (RO) Model Uniformity – November 19, 2020
4. Workshop No. 4 - Standardization of RAMP Filings – February 2021

The IOUs are supporting ED staff in facilitating the workshops, and an IOU has been designated for each workshop. The RCP Decision also requires that no later than 30 days after the conclusion of the workshop, the designated IOU shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies served on the service list of R.13-11-006 summarizing the workshop and any agreed-upon proposals.

4. Workshop

ED held the third public workshop virtually via a recorded WebEx session on November 19, 2020. Due to the state's public health order in response to the COVID-19 pandemic, there was no in-person attendance. ED sent a notice of the workshop to the service list for R.13-11-006. The public workshop notice was posted on the CPUC's Daily Calendar and website. The workshop, scheduled from 10:00 am – 1:45 pm, included five agenda topics, followed by open discussion:

- Introduction to RO Model
- Standard Format for Summary of Earnings
- User-Friendly Interface
- Uniform RO Model Format & Structure
- Working Relationship with Administrative Law Judge & Energy Division

ED staff began the workshop by discussing the workshop logistics and background. SCE then provided an overview of the agenda and goals of the workshop. In addition to ED staff, identified attendees at the workshop included PG&E, SCE, SDG&E, SoCalGas, Bear Valley Electric, The Utility Reform Network (TURN), and the CPUC Public Advocates Office (Cal Advocates). While the RCP Decision identified Cal Advocates as the only party that runs the RO model aside from the utilities, Cal Advocates staff declined an invitation to present information on its RO modeling process or experience at the workshop. In addition, the RCP decision indicates that if any intervenors can demonstrate the value of greater standardization, the utilities should consider those recommendations. Any refinements that ease the burden on GRC parties are likely to translate into greater efficiencies for the Commission's decision making.

5. Topic 1: Introduction to RO Model

5.1 IOU Presentation on Introduction to RO Model

On behalf of the IOUs, SCE provided a brief and high-level overview of the model so that attendees who are less familiar with the model would be able to share a basic understanding of what the RO model is, why they are used, and what they are designed to accomplish. SCE emphasized that the IOUs work with the aim of bringing greater simplicity and transparency to this complex and technical area, and as such review their RO models prior to the beginning of every GRC to determine if there are opportunities for improvement that would serve this purpose.

SCE then defined the terms "revenue requirement" and "return on rate base." SCE then pointed out the primary types of calculations and adjustments a user can make with the model. These are:

- Change O&M/Administrative and General (A&G)/Other Operating Revenue (OOR) and Capital Expenditure forecasts
- Change depreciation rates
- Calculate the lead-lag portion of working cash
- Calculate all taxes and tax depreciation
- Make plant adjustments including adjustments to beginning-of-year plant balances
- Calculate Revenue Requirement and Summary of Earnings

SCE concluded this introductory section by discussing the standard features found in each IOU's RO model. These are user guides, tracking tools/audit logs, jurisdictional cost of service between FERC and CPUC, functionalization between distribution, generation, and gas (where applicable), and labor allocators to allocate general expenses.

6. Topic 2: Standard Format for Summary of Earnings

6.1 IOU Presentation on Standard Format for Summary of Earnings

SCE began by pointing out that each IOU's SoE contains the same foundational principles, with each aligned toward the specific business operations and accounting and financial systems of each IOU. In order to determine if there are areas for further alignment, the IOUs collectively shared and reviewed their most recent GRC Decision appendix summary tables, as well as testimony tables, and workpaper content and structure. After completing this review, the IOUs determined that they all have the same general format and content, but there are some subtle differences.

At the workshop SCE walked through the components of each IOU's SoE and discussed areas where there are presentation and format differences. The IOUs believe these differences are reasonable and appropriate; however there are opportunities for future alignment, which the IOUs have agreed to jointly explore, while remaining sensitive to the fact that each model may vary to align with individual business needs. Three areas were specifically discussed for future joint exploration with the aim toward standardization:

- Revenue Requirement/Other Operating Revenue
    - SCE presents Other Operating Revenue (OOR) as a separate line item within Operation and Maintenance (O&M) and Administrative and General (A&G) expenses, while other IOUs present OOR within the total revenue requirement
- O&M Escalation
    - SCE, SDG&E and SoCalGas presents this as a separate line item, while PG&E embeds escalation within O&M and A&G
- Uncollectible Expense and Franchise Requirements
    - There are slight differences among the IOUs

7. Topic 3: User-Friendly Interface

7.1 IOU Presentation on User-Friendly Interface

SCE stated that each RO model contains standardization tailored towards the internal business needs of each IOU. This includes standardized color coding (e.g. for inputs and recorded year balances), output tables (e.g. SoE, O&M summary, and rate base), and file names (e.g. O&M, Capital, and Tax). SCE then provided examples from each IOU to demonstrate the formatting and color-coding schemes employed in each IOU's RO model. While there are some slight differences between IOUs, each is standardized within its own model in order to create a user-friendly interface.

8. Topic 4: Uniform RO Model Format & Structure

8.1 IOU Presentation on Uniform RO Model Format & Structure

SCE shared that each IOU's RO model format and structure are tailored towards internal business requirements. However, RO models share similar foundational principles to bridge a generally uniform "look and feel" across IOUs. These are:

- O&M/A&G, Capital, Tax, and Summary modules
- User Guides (to show how model users should go about making changes, e.g. adjusting capital related projects)
- Data flow diagrams (to demonstrate how data flows from one workbook to another and across the model)
- Processing sequence
- Identification of inputs that can be changed

IOUs also offer a similar suite of support services to the CPUC and parties who wish to have a deeper understanding of their model. This includes holding RO model workshops following the filing of a GRC application, which are typically at the Commission's offices and highlight any changes to the model from the previous rate case. IOUs will also hold more detailed working sessions on specific aspects of the model to show users the details behind the calculations. SCE noted that the IOUs continue to work together to identify opportunities to align across the utilities to enhance uniformity.

SCE then provided a high-level walk-through of each IOU's model architecture in order to show how the data in each interdependent module flows within and between workbooks, i.e. one workbook's outputs becomes another workbook's inputs, in addition to any changes made by the user. In addition, any changes made to the O&M, Capital, and Tax modules flow to the Summary module. SDG&E/SoCalGas

noted that, like SCE, each section of their RO model flows into each other; and though the flow is slightly different among the IOUs, the functions are similar. PG&E noted that the PG&E diagram is a very high-level overview of the model's structure. Following this walk-through, SCE presented conceptual diagrams to demonstrate the processing sequence of each IOU's model.

8.2 Discussion on the IOUs' Presentation

ED asked how shared cost expenditures are allocated in the RO models, e.g. building insurance premium, shared cost between administrative and program cost, etc. SCE stated that, speaking for itself, it separates shared costs between FERC and CPUC jurisdictions, and then among functions (e.g., Distribution, Generation, Gas) and various balancing accounts. This is determined through a labor allocator assigned to different functions. PG&E stated that it takes a somewhat similar approach. In most cases PG&E uses recorded base year O&M expense dollars to develop factors to allocate shared costs across FERC and CPUC, which is then further allocated among components within CPUC. SDG&E/SoCalGas stated that it looks at historical information for allocation factors for gas and electric distribution. SDG&E/SoCalGas is also unique in its sharing of costs between the two utilities and relies on its witnesses to develop shared costs.

9. Topic 5: Working Relationship with ALJ & Energy Division

9.1 Energy Division Presentation on RO Modeling Process at the CPUC

ED presented on the RO modeling process at the CPUC and the relationship with IOUs. ED staff support the ALJ in a GRC by ensuring that the information provided to the ALJ for the PD, such as revenue requirement and RO model results, are accurate. The CPUC will, under an NDA, work with an IOU modeler to model the PD adjustments. ED will also seek interpretations and clarifications from ALJs and communicate relevant information to the IOU modeler when needed. The IOU modeler works under CPUC staff supervision to create detailed workpapers to support the effort. Workpapers are available to any parties who request them.

9.2 IOU Presentation on Working Relationship with ALJ & Energy Division

SCE explained how the CPUC and an IOU typically work together when the CPUC requests that the IOU assist ED and ALJ in connection with RO modeling while the PD is being developed. SCE first noted that utility participation in assisting with PD RO modeling is entirely determined by the CPUC, and represents an effort to leverage resources and efficiencies by tapping into IOU modeling expertise. Generally, the IOU modeling resource assists in whatever way ED and the ALJ deem necessary. Each modeling resource provided by an IOU is required to first enter into an NDA that governs the utility's assistance with the CPUC's RO modeling. If the utility is invited to participate, the designated expert(s) signs a "black box" NDA, which calls for the expert(s) to not disclose any information to the public nor to anyone at the utility, including legal counsel. The NDA is also "evergreen," in that there is no expiration date of the obligation to refrain from discussing or disclosing the items covered under the NDA.

Generally, the IOUs support the current process in the following ways when invited to participate by the CPUC:

- Engaging in working sessions with ED to share knowledge and foster familiarity with IOU RO Models
- Collaboratively creating templates and workpapers to support and perform modeling inputs

- Validating modeling results and supporting the generation of GRC Decision financial tables.

SCE also stated that, prior to the COVID-19 pandemic, the southern California utility RO expert(s) would travel to San Francisco for weeks at a time to assist in this effort. This effort can be burdensome and carries with it the expense associated with extended travel. During the course of its most recent rate case, PG&E was afforded the opportunity to assist the CPUC via remote RO modeling.[1] The IOUs proposed that this accommodation be extended to future rate cases, with the caveat that if in-person collaboration is ever needed then utility experts will continue to travel to CPUC offices. However, remote modeling would be the default going forward.

9.3 Discussion on the Energy Division and IOUs' Presentations

TURN noted that the IOUs' proposals seemed generally reasonable. TURN requested that RO modeling be as transparent as possible. SCE noted that the IOUs cannot share information concerning the PD RO modeling, because any such sharing with any non-CPUC person would constitute a violation of the NDA. SCE also identified concerns that would be raised if RO PD modeling information is selectively provided to one party versus another, and noted that disclosing RO modeling information and results (which carry significant economic and financial implications) before the PD is issued by the Commission could result in market effects or other negative consequences.

ED asked if the IOUs are proposing to make a checklist or spreadsheet in addition to the workpapers. SCE responded that, speaking for SCE, workpapers are a support process to validate numbers, and to make the overall modeling easier to perform. Workpapers also ensures the PD uses the most recent numbers on the record, help with needed supporting calculations, and serve as a guide as to where to go in the model to change a specific workbook and cell. The IOUs remain open to a collaborative effort to make sure workpapers and the process continue to meet ED's needs.

Regarding the proposal to permit remote IOU RO modeling in support of the CPUC, ED inquired if compared to pre-pandemic did the IOUs encounter any problems working remotely on the model, as opposed to in-person. PG&E is the only utility that has thus far participated in this effort remotely and responded that in their case it was a smooth process. ED followed up by inquiring about how PG&E was able to deal with modeling inputs, including if PG&E used templates or workpapers. PG&E replied that it cannot comment on the specifics due to the NDA, but in terms of process ED provided what inputs need to be changed. PG&E maintained a separate laptop for modeling and created a confidential folder within the utility's internal shared drive. PG&E and ED also established a confidential File Transfer Protocol (FTP). PG&E and ED held regular weekly calls, where screens were shared over Webex. ED concluded by stating that this process seems to have worked well. ED will consider the IOU proposal and bring it up to ED management.

In regards to the general display of information in the model, Cal Advocates suggested that separating A&G expense could be helpful to split out and display separately as there are some adjustments that are unique to A&G. SCE stated it can work with Cal Advocates offline on recommendations to make certain aspects of the model more transparent and adjustments easier to make.

[1] Administrative Law Judges' Ruling Adopting Amended Confidential Modeling Procedures, issued August 13, 2020.

9.4 Post Workshop Comments on Working Relationship with ALJ & Energy Division

In their post-workshop comments the IOUs raised two points. First, the IOUs responded to TURN's comment made during the workshop that consideration should be given to maximizing the transparency of the specifics of the utility's RO modeling assistance to the Commission in connection with the PD. The IOUs stated that: (1) any such disclosure by the utility would violate the non-disclosure agreement that the utility executes with the Commission; (2) prematurely disclosing such content before it has been accepted, validated, and finalized by the Commission personnel could lead to negative consequences; and (3) any change to the current protocols in this regard should originate from the Commissioners.

Second, the IOUs responded to the workshop discussion on the merits of authorizing remote PD modeling for utility RO model experts. In addition, the IOUs believe no formal regulatory ruling or activity is necessary to implement the concepts introduced during the Workshop, except for the remote modeling proposal. The IOUs encourage the Commission to authorize remote modeling as the default in support of PD development, with utility experts only traveling to Commission offices if specifically directed by the ALJs or Assigned Commissioner presiding over a given GRC proceeding. The IOUs reiterated their support for remote modeling and urged the ED Staff to discuss the proposal within the Commission. See Appendix B for the IOU comments.

11. Next Steps

Comments should be sent to the SCE representative and to ED. The schedule for comments and the report is:

- Workshop Comments: November 25, 2020
- Draft Report: December 7, 2020
- Draft Report Comments: December 14, 2020
- Final Report: December 21, 2020

The final report is to be issued within 30 days of the workshop conclusion and is to be sent to the Directors of Energy Division, Safety Policy Division, and the Safety and Enforcement Division, as well as to the proceeding service list.

12. Appendix A: Workshop Presentation

Rate Case Plan (Decision 20-01-002)

Workshop No. 3
Uniformity in Results of Operations (RO) Model

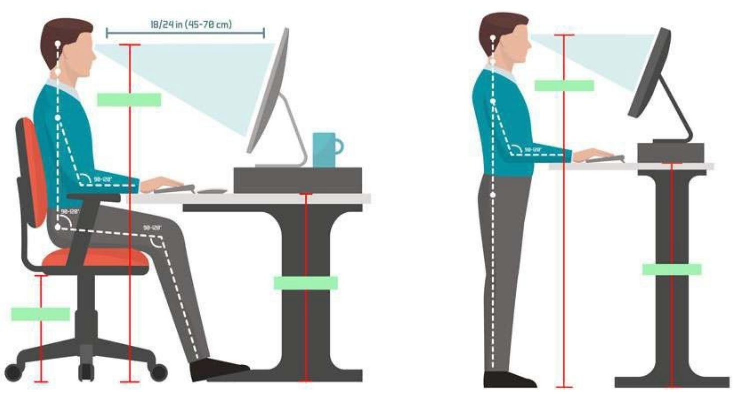
November 19, 2020
10 am – 1:45 pm
(with Lunch Break)
California Public Utilities Commission (CPUC)

CPUC Energy Division
SCE Lead

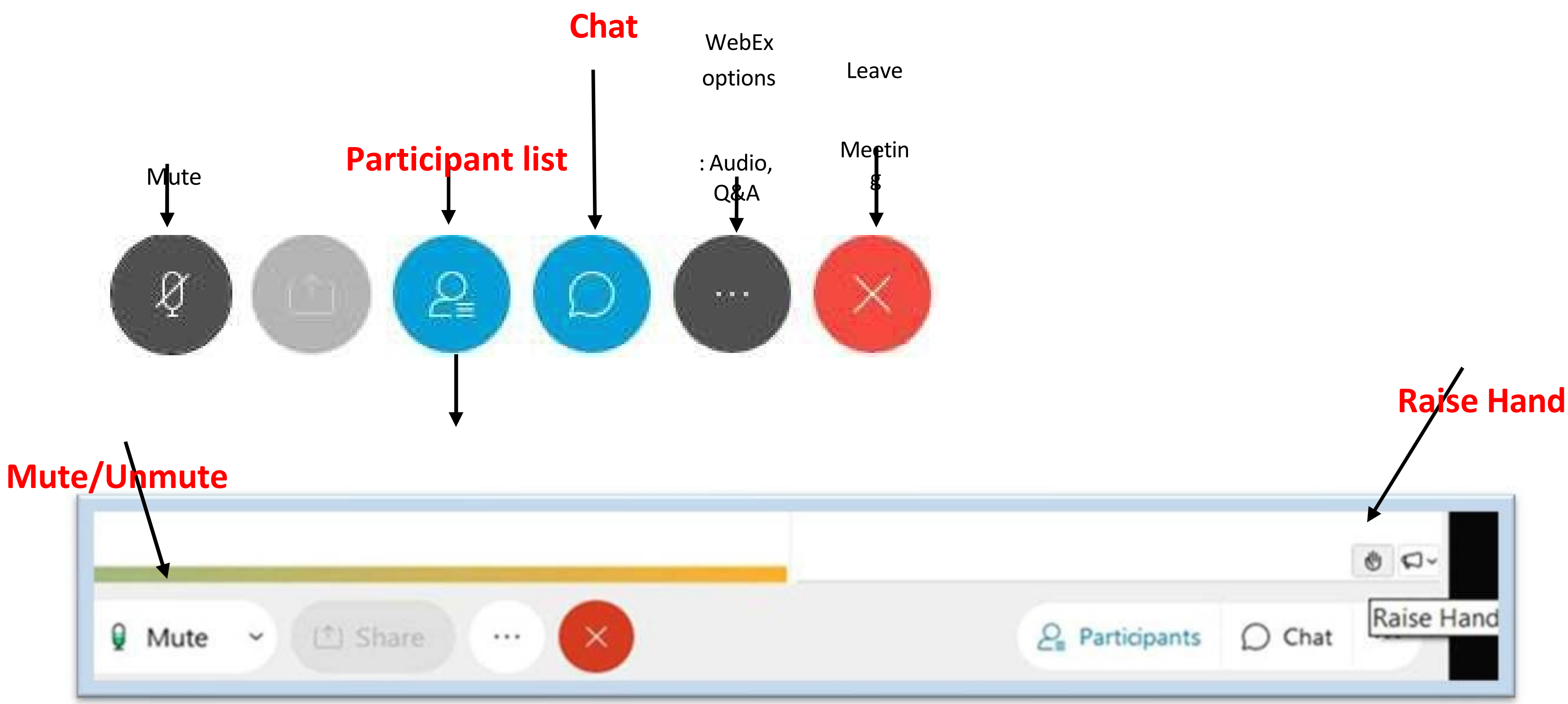
California Public
Utilities Commission

Workshop Logistics

- Online only
  - Audio through computer or phone
  - Dial 415-655-0002
  - Access code: 146 292 5835
  - ***This workshop is being recorded***
- Hosts:
  - SCE Representatives
  - Energy Division Staff:
    - Gelila Berhane
    - Jenny Au
- Safety
  - Note surroundings and emergency exits
  - Ergonomic Check



How to Use WebEx



Introductions

- CPUC – Energy Division
- Facilitators – SCE Representatives
- Panelists – SCE, PG&E, and Sempra Utilities
- Organizations – via **Chat function**

Workshop Purpose

- Meet requirements of RCP Decision 20-01-002
- Series of four workshops
  - Workshop #1 – Stipulated Terms & Rebuttal Presumptions – September 4, 2020.
  - Workshop #2 - General Rate Case Filing Standardization – October 7, 2020.
  - Workshop #3 – RO Modeling – November 19, 2020
  - Workshop #4 – RAMP Filing – February 2021
- Reports are available at https://www.cpuc.ca.gov/General.aspx?id=6442454678

SOUTHERN CALIFORNIA EDISON®
An EDISON INTERNATIONAL® Company

Rate Case Plan Workshop #3
Results Of Operations (RO) Model

November 19, 2020

Rate Case Plan Workshop #3 - Agenda

Topic	Facilitator	Time
Introduction & Meeting Goals	Energy Division Kris Vyas (SCE)	15 minutes
Introduction to RO Model	Doug Tessler (SCE)	15 minutes
Standard Format for Summary of Earnings	Doug Tessler (SCE)	15 minutes
User-Friendly Interface	Doug Tessler (SCE)	30 minutes
Uniform RO Model Format & Structure	David Gunn (SCE)	30 minutes
LUNCH		45 minutes
Working Relationship with ALJ & Energy Division	Kris Vyas (SCE)	30 minutes
Open Discussion	Doug Tessler (SCE)	30 minutes
Next Steps and Wrap Up	Energy Division Kris Vyas (SCE)	15 minutes

Introduction & Meeting Goals

- Decision 20-01-002 recommended a future workshop to “explore ways to make the RO models of the four utilities more uniform and user-friendly”. Issues to be discussed should include:
  - Developing a standard format for the Summary of Earnings table
  - Developing a user-friendly input interface for the RO model
  - Developing a uniform RO model format or structure
  - Utilities to explain their perspectives and develop a single approach to their working relationship with the ALJ and Energy Division staff

Introduction to RO Model

Why the RO Model is Used in GRCs

In D.00-07-050 the Commission has stated that the single most important effort to streamline proceedings is to ensure the simplification and transparency of the RO Model

- A user-friendly model facilitates the quick calculation of a Revenue Requirement for various scenarios, allowing for quicker turnaround in the GRC process

With only moderate training, a user should be able to accomplish the following:

- Change O&M/A&G/OOR and Capital Expenditure forecasts
- Change depreciation rates
- Calculate the lead-lag portion of working cash
- Calculate all taxes and tax depreciation
- Make plant adjustments including adjustments to beginning-of-year plant balances
- Calculate Revenue Requirement and Summary of Earnings

In the spirit of promoting simplicity and transparency, IOUs review the RO Model prior to the commencement of every GRC to assess opportunities for improvement.

Revenue Requirement and Rate Base

Revenue Requirement	
	O&M/A&G
+	Depreciation Expense
+	Property Tax Expense
+	Payroll Tax Expense
+	Income Tax Expense
+	Return on Rate Base
=	**Revenue Requirement**

Return on Rate Base	
	Net Plant-In-Service
+	Working Capital
–	Reserves
–	Accumulated Deferred Taxes
=	**Rate Base**
x	Rate of Return
=	**Return on Rate Base**

CA IOU RO Models – Standard Features

- IOU RO models are excel-based with background VBA code to "run" the model
  - Visual Basic (VBA) code is the standard protocol to "run" the model:
    - Code opens files, refreshes links, saves and closes files
  - Average IOU run time is approximately 10-20 minutes
- User Guides are provided with the RO models
  - PC requirements
  - Structure of model
  - "How to" sections with examples
  - Troubleshooting
- Tracking Tool/Audit Log to document changes
- Jurisdictionalization between FERC and CPUC
- Functionalization between Distribution, Generation, Gas
- Labor Allocator: Dynamic calculation to allocate general expenses and expenditures between Jurisdictions (SCE) and Functions (All IOUs)

Standard Format for Summary of Earnings (SoE)

Standard Format for Summary of Earnings (SoE)

- To identify improvements and movement toward standardization, IOUs reviewed:
  - Decision Appendix Summary Tables
  - Testimony tables and workpaper content and structure

IOUs' Summary of Earnings contain the same foundational principles, each aligned toward the specific business operations and accounting and financial systems.

SoE – High Level IOU Comparison

SCE

Appendix C | 2018 CPUC Results of Operations

Line	Item
1.	**Total Operating Revenues**
2.	**Operating Expenses:**
3.	Production
4.	Steam
5.	Nuclear
6.	Hydro
7.	Other
8.	Total Production O&M
9.	Transmission
10.	Distribution
11.	Customer Accounts
12.	Uncollectibles
13.	Customer Service & Information
14.	Administrative & General
15.	Franchise Requirements
16.	Revenue Credits
17.	**Total O&M**
18.	**Escalation**
19.	**Depreciation**
20.	Taxes Other Than On Income
21.	Taxes Based On Income
22.	**Total Taxes**
23.	**Total Operating Expenses**
24.	**Net Operating Revenue**
25.	**Rate Base**
26.	**Rate of Return**
27.	**Revenues at Present Rates**
28.	**Increase/(Decrease) Over Present Revenue Requirement In Rates**
29.	**Balancing/Memorandum Account Undercollection**
30.	**Net Increase/(Decrease) Over Present Rates**
31.	**Decrease Over Present Revenue Requirement In Rates**
32.	**Net Decrease Over Present Rates**

PG&E

Line No.	Description
	REVENUE:
1	Revenue Collected in Rates
2	Plus Other Operating Revenue
3	Total Operating Revenue
	OPERATING EXPENSES:
4	Energy Costs
5	Production / Procurement
6	Storage
7	Transmission
8	Distribution
9	Customer Accounts
10	Uncollectibles
11	Customer Services
12	Administrative and General
13	Franchise & SFGR Tax Requirement
14	Amortization
15	Wage Change Impacts
16	Other Price Change Impacts
17	Other Adjustments
18	Subtotal Expenses:
	TAXES:
19	Superfund
20	Property
21	Payroll
22	Business
23	Other
24	State Corporation Franchise
25	Federal Income
26	Total Taxes
27	Depreciation
28	Fossil/Hydro Decommissioning
29	Nuclear Decommissioning
30	Total Operating Expenses
31	Net for Return
32	Rate Base
	RATE OF RETURN:
33	On Rate Base
34	On Equity

SDG&E | SoCal Gas

Line No.	Description	
1	Base Margin	
2	Miscellaneous Revenues	
3	Revenue Requirement	
	Operating and Maintenance Expenses	
4	Gas Distribution	
5	Transmission	
6	Underground Storage	
7	Engineering	
8	PSEP	
9	Procurement	
10	Customer Services	
11	Information Technology	
12	Support Services	
13	Administrative and General	
14	Subtotal (2016$)	
15	Shared Services Adjustments	
16	Reassignments	
17	Escalation	
18	Uncollectibles (0.313%)	
19	Franchise Fees (1.372%)	
20	Total O&M (2019$)	
21	Depreciation & Amortization	
22	Taxes on Income	
23	Taxes Other Than on Income	
24	Total Operating Expenses	
25	Return	
26	Rate Base	
27	Rate of Return	
28	Derivation of Base Margin	
29	O&M Expenses	(Line 20)
30	Depreciation	(Line 21)
31	Taxes	(Line 22+23)
32	Return	(Line 25)
33	Revenue Requirement	
34	Less: Miscellaneous Revenues	(Line 2)
35	Base Margin	(Line 1)

SoE – SCE With Detail

Line	Item	Adopted CPUC Total	SCE Request (Based on Feb 2018 Tax Update Testimony)	Difference (Adopted Less SCE Request)
	Appendix C | 2018 CPUC Results of Operations			
1.	**Total Operating Revenues**	**5,115,860**	**5,534,406**	**(418,546)**
2.	**Operating Expenses:**			
3.	Production			
4.	Steam	6,251	7,845	(1,594)
5.	Nuclear	76,747	76,747	–
6.	Hydro	41,446	41,446	–
7.	Other	81,962	81,965	(3)
8.	Total Production O&M	206,406	208,003	(1,597)
9.	Transmission	91,023	91,118	(95)
10.	Distribution	497,023	532,099	(35,077)
11.	Customer Accounts	155,395	159,329	(3,934)
12.	Uncollectibles	10,879	11,954	(1,075)
13.	Customer Service & Information	21,277	21,007	270
14.	Administrative & General	608,210	647,853	(39,644)
15.	Franchise Requirements	47,145	50,607	(3,461)
16.	Revenue Credits	(151,220)	(153,070)	1,850
17.	**Total O&M**	**1,486,137**	**1,568,900**	**(82,763)**
18.	**Escalation**	**95,628**	103,952	**(8,324)**
19.	**Depreciation**	**1,579,362**	1,752,338	**(172,976)**
20.	Taxes Other Than On Income	315,332	324,801	(9,469)
21.	Taxes Based On Income	(19,063)	38,919	(57,982)
22.	**Total Taxes**	**296,269**	**363,720**	**(67,451)**
23.	**Total Operating Expenses**	**3,457,396**	**3,788,910**	**(331,514)**
24.	**Net Operating Revenue**	**1,658,464**	**1,745,496**	**(87,032)**
25.	**Rate Base**	22,321,623	22,939,281	(617,659)
26.	**Rate of Return**	7.43%	7.61%	14.09%
27.	**Revenues at Present Rates**	5,640,432	5,640,432	
28.	**Increase/(Decrease) Over Present Revenue Requirement In Rates**	(524,572)	(106,026)	(418,546)
29.	**Balancing/Memorandum Account Undercollection**	41,469	41,469	–
30.	**Net Increase/(Decrease) Over Present Rates**	(483,103)	(64,557)	(418,546)
31.	**Decrease Over Present Revenue Requirement In Rates**	-9.30%		
32.	**Net Decrease Over Present Rates**	-8.57%		

Line	Item	2018 Total CPUC	Generation	Peakers	Distribution
	With Adjustments				
1.	**Total Operating Revenues**	**5,115,860**	**644,723**	**56,938**	**4,414,199**
2.	**Operating Expenses:**				
3.	Production				
4.	Steam	6,251	6,251	–	–
5.	Nuclear	76,747	76,747	–	–
6.	Hydro	41,446	41,446	–	–
7.	Other	81,962	74,511	7,451	–
8.	Total Production O&M	206,406	198,955	7,451	–
9.	Transmission	91,023	–	–	91,023
10.	Distribution	497,023	–	–	497,023
11.	Customer Accounts	155,395	–	–	155,395
12.	Uncollectibles	10,879	1,360	120	9,398
13.	Customer Service & Information	21,277	1,597	–	19,680
14.	Administrative & General	608,210	83,040	4,388	520,781
15.	Franchise Requirements	47,145	5,895	521	40,729
16.	Revenue Credits	(151,220)	(1,871)	–	(149,349)
17.	**Total O&M**	**1,486,137**	**288,976**	**12,480**	**1,184,680**
18.	**Escalation**	**95,628**	**19,940**	**425**	**75,263**
19.	**Depreciation**	**1,579,362**	**161,917**	**14,467**	**1,402,978**
20.	Taxes Other Than On Income				
21.	Property Taxes	255,217	21,798	3,535	229,884
22.	Payroll Taxes & Misc	60,115	8,594	47	51,474
23.	Taxes Based On Income	(19,063)	(8,917)	7,632	(17,778)
24.	**Total Taxes**	**296,269**	**21,475**	**11,214**	**263,580**
25.	**Total Operating Expenses**	**3,457,396**	**492,308**	**38,586**	**2,926,502**
26.	**Net Operating Revenue**	**1,658,464**	**152,415**	**18,352**	**1,487,697**
27.	Rate Base	22,321,623	2,003,032	241,180	20,077,411
28.	Rate Of Return	7.43%	7.61%	7.61%	7.41%

SoE – SDG&E/SoCalGas With Detail

Table KN-2
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2019
ELECTRIC SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description	2019 Present Rates (2019$)	2019 Proposed Rates (2019$)
1	Base Margin	$ 1,637,656	$ 1,748,829
2	Miscellaneous Revenues	15,852	14,653
3	Revenue Requirement	$ 1,653,508	$ 1,763,482
	OPERATING & MAINTENANCE EXPENSES		
4	Distribution	157,783	157,783
5	Gas Transmission	-	-
6	PSEP	-	-
7	Generation	63,131	63,131
8	Engineering	-	-
9	Procurement	8,641	8,641
10	Customer Services	59,422	59,422
11	Information Technology	71,478	71,478
12	Support Services	78,040	78,040
13	Administrative and General	435,493	435,493
14	Subtotal (2016$)	873,988	873,988
15	Shared Services Adjustments	(24,626)	(24,626)
16	Reassignments	(142,668)	(142,668)
17	FERC Transmission Costs	(82,815)	(82,815)
18	Escalation	22,877	22,877
19	Uncollectibles (0.174%)	2,850	3,043
20	Franchise Fees (3.4468%)	56,447	60,279
21	Total O&M (2019$)	706,053	710,078
22	Depreciation & Amortization	474,694	474,694
23	Taxes on Income	33,485	65,087
24	Taxes Other Than on Income	102,451	102,451
25	Total Operating Expenses	$ 1,316,683	$ 1,352,310
26	Return	336,825	411,172
27	Rate Base	5,443,898	5,445,982
28	Rate of Return	6.19%	7.55%

Table KN-5
SAN DIEGO GAS & ELECTRIC COMPANY
TEST YEAR 2019
GAS SUMMARY OF EARNINGS
(Thousands of Dollars)

Line No.	Description	2019 Present Rates (2019$)	2019 Proposed Rates (2019$)
1	Base Margin	$ 324,291	$ 432,393
2	Miscellaneous Revenues	4,206	2,843
3	Revenue Requirement	$ 328,497	$ 435,236
	OPERATING & MAINTENANCE EXPENSES		
4	Distribution	36,480	36,480
5	Gas Transmission	6,668	6,668
6	PSEP	-	-
7	Generation	280	280
8	Engineering	11,000	11,000
9	Procurement	-	-
10	Customer Services	35,031	35,031
11	Information Technology	24,879	24,879
12	Support Services	22,314	22,314
13	Administrative and General	112,067	112,067
14	Subtotal (2016$)	248,718	248,718
15	Shared Services Adjustments	6,265	6,265
16	Reassignments	(41,185)	(41,185)
17	FERC Transmission Costs		
18	Escalation	10,024	10,024
19	Uncollectibles (0.174%)	564	752
20	Franchise Fees (2.0799%)	6,745	8,993
21	Total O&M (2019$)	231,132	233,568
22	Depreciation & Amortization	84,968	84,968
23	Taxes on Income	(15,357)	15,756
24	Taxes Other Than on Income	22,151	22,151
25	Total Operating Expenses	$ 322,894	$ 356,444
26	Return	5,603	78,792
27	Rate Base	1,041,851	1,043,608
28	Rate of Return	0.54%	7.55%

SoE – PG&E With Detail

APPENDIX A: Table 3-A
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Revenue Collected in Rates	4,151,048	4,151,048	0	1
2	Plus Other Operating Revenue	117,977	117,977	0	2
3	Total Operating Revenue	4,269,025	4,269,025	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	0	0	0	5
6	Storage	0	0	0	6
7	Transmission	1,066	1,066	0	7
8	Distribution	710,221	710,221	0	8
9	Customer Accounts	173,659	173,659	0	9
10	Uncollectibles	14,454	14,454	0	10
11	Customer Services	19,048	19,048	0	11
12	Administrative and General	381,817	381,817	0	12
13	Franchise & SFGR Tax Requirement	33,346	33,346	0	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(6,420)	(6,420)	0	17
18	Subtotal Expenses:	1,327,191	1,327,191	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	167,698	167,698	0	20
21	Payroll	39,116	39,116	0	21
22	Business	453	453	0	22
23	Other	1,076	1,076	0	23
24	State Corporation Franchise	72,073	72,073	0	24
25	Federal Income	181,580	181,580	0	25
26	Total Taxes	461,996	461,996	0	26
27	Depreciation	1,364,495	1,364,495	0	27
28	Fossil/Hydro Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	3,153,681	3,153,681	0	30
31	Net for Return	1,115,344	1,115,344	0	31
32	Rate Base	13,838,010	13,838,010	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

APPENDIX A: Table 3-B
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Revenue Collected in Rates	1,738,493	1,738,493	0	1
2	Plus Other Operating Revenue	28,091	28,091	0	2
3	Total Operating Revenue	1,766,584	1,766,584	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	3,286	3,286	0	5
6	Storage	0	0	0	6
7	Transmission	0	0	0	7
8	Distribution	429,689	429,689	0	8
9	Customer Accounts	116,810	116,810	0	9
10	Uncollectibles	5,642	5,642	0	10
11	Customer Services	22,273	22,273	0	11
12	Administrative and General	258,547	258,547	0	12
13	Franchise & SFGR Tax Requirement	16,291	16,291	0	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(3,495)	(3,495)	0	17
18	Subtotal Expenses:	849,043	849,043	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	53,820	53,820	0	20
21	Payroll	30,790	30,790	0	21
22	Business	297	297	0	22
23	Other	707	707	0	23
24	State Corporation Franchise	(14,482)	(14,482)	0	24
25	Federal Income	(50,406)	(50,406)	0	25
26	Total Taxes	20,726	20,726	0	26
27	Depreciation	480,014	480,014	0	27
28	Fossil/Hydro Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,349,782	1,349,782	0	30
31	Net for Return	416,801	416,801	0	31
32	Rate Base	5,171,234	5,171,234	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

APPENDIX A: Table 3-C
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Revenue Collected in Rates	2,114,946	2,114,946	0	1
2	Plus Other Operating Revenue	6,025	6,025	0	2
3	Total Operating Revenue	2,120,971	2,120,971	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	644,140	644,140	0	5
6	Storage	0	0	0	6
7	Transmission	6,050	6,050	0	7
8	Distribution	0	0	0	8
9	Customer Accounts	2,403	2,403	0	9
10	Uncollectibles	7,181	7,181	0	10
11	Customer Services	0	0	0	11
12	Administrative and General	271,819	271,819	0	12
13	Franchise & SFGR Tax Requirement	16,567	16,567	0	13
14	Amortization	176	176	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(20,000)	(20,000)	0	17
18	Subtotal Expenses:	928,336	928,336	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	56,197	56,197	0	20
21	Payroll	32,612	32,612	0	21
22	Business	308	308	0	22
23	Other	733	733	0	23
24	State Corporation Franchise	24,561	24,561	0	24
25	Federal Income	95,821	95,821	0	25
26	Total Taxes	210,233	210,233	0	26
27	Depreciation	550,402	550,402	0	27
28	Fossil/Hydro Decommissioning	3,094	3,094	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,692,065	1,692,065	0	30
31	Net for Return	428,906	428,906	0	31
32	Rate Base	5,321,410	5,321,410	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

SoE – Presentation/Format Differences

- Revenue Requirement | Other Operating Revenue
  - PG&E | SDG&E | SoCal Gas: Presented with total revenue requirement
  - SCE: Separate line items within O&M section
- Escalation:
  - SCE | SDG&E | SoCal Gas: separate line item below O&M
  - PG&E: embedded in O&M
- Uncollectible Expense & Franchise Requirements:
  - SCE | PG&E: Separate line items within O&M section
  - SDG&E | SoCalGas: Separate line items after O&M and escalation section

IOUs' Summary of Earnings contain reasonable and appropriate differences, however, opportunities for future alignment exist and will be jointly explored.

User-Friendly Interface

User-Friendly Interface

- IOU RO models contain standardization tailored towards internal business needs:
  - Standardized Color Coding
    - Inputs to effectuate changes
    - Recorded year balances
  - Standard output tables (e.g. SoE, O&M summary, rate base, etc.)

- File names
  - Standardization exists within each IOU RO model
    - Files are identifiable (e.g., O&M, Capital, Tax)

Formatting & Color Coding

Cell Formatting			
Cell Type	**SCE**	**SDG&E / SoCalGas**	**PG&E**
Inputs/Plugs where changes are not meant to be made	Blue	Blue	Black
Inputs/Plugs where changes are meant to be made	Blue | Yellow Shading	Blue | Yellow Shading	Black | Green Shading
Links to Worksheets	Green	Black	Black
Links to Workbooks	Red	Red	Black
Calculations	Black	Black	Black

Tab/Worksheet Formatting			
Tab/Worksheet Type	**SCE**	**SDG&E / SoCalGas**	**PG&E**
Inputs	Tab Name	N/A	Black | Green Shading
Calculations	Tab Name	N/A	Black
Outputs	Tab Name	N/A	Black
Tab Divider (Inputs, Calculations, Outputs)	|| Tab Divider Name ||	|| Tab Divider Name ||	|| Tab Divider Name ||
Info Tab	|| Info Tab ||	|| Info ||	|| Module Name TOC/Notes ||
Audit Log	|| Audit Log ||	|| Tracker ||	|| Tracker ||
Checks	|| Checks ||	|| Validation ||	|| Check / Comparison ||

SCE – Example of User-Friendly Interface

- Escalation:

Labor					
Escalation Rates	**2019**	**2020**	**2021**	**2022**	**2023**
Steam	2.89%	3.48%	2.76%	3.49%	3.43%

Non-Labor					
Escalation Rate	**2019**	**2020**	**2021**	**2022**	**2023**
Steam	2.46%	(0.82%)	(0.55%)	2.21%	2.70%

- O&M | A&G | OOR:

FERC Account	GRC Activity Name	Testimony Exhibit	Witness	Cost Type	2021 Forecast	2021 Adjustments	2021 Adj Forecast
454	SCE-Financed Added Facilities	SCE-02, Vol. 7	T. Reeves	O	34,227	(39)	34,188
560	Grid Engineering	SCE-02, Vol. 4 Pt. 2	D. Cabbell	L	2,462		2,462
560	Grid Engineering	SCE-02, Vol. 4 Pt. 2	D. Cabbell	NL	1,559		1,559

- Capital Expenditures:

					Forecast Capital Expenditures			Capital Expenditure Adjustments			Adjusted Capital Expenditure Forecast		
RO Model ID	GRC Activity	Exhibit	Witness	WBS	2019	2020	2021	2019	2020	2021	2019	2020	2021
10	Underground Structure Replacements	SCE-02, Vol. 1 Pt. 1	R. Tucker	CET-PD-IR-UG-MTE	8,015	8,208	8,420	(8,015)			-	8,208	8,420
11	Underground Structure Replacements	SCE-02, Vol. 1 Pt. 1	R. Tucker	CET-PD-IR-UG-MTW	19,558	13,563	5,142	28,689			48,247	13,563	5,142

SDG&E/SoCalGas – Example of User-Friendly Interface

- Escalation:

SDG&E-N [NSS - L / NL / NSE]

	Non-Composite				Composite
	Elec/Gen/Gas Labor	Elec/Gen Non-Labor (Nlbr)	Gas Non-Labor (Nlbr)	Elec/Gen/Gas NSE	Elec/Gen/Gas Composite
2016	1	1	1	1	0
2017	1.0244	1.0146	1.019	1	0
2018	1.0539	1.0435	1.0453	1	0
2019	1.0869	1.0648	1.0648	1	0
2019 Revised	1.0869	1.0648	1.0648	1	0
Variance	0	0	0	0	0

- O&M | A&G | OOR:

Company: SDG&E [2100-NSS]
SOE Area: A&G
Functional Area: AGAG
Wkp Grp - Sub: 1AG001-000
Wkp Grp Desc: Oper CCTR-NSS-Controllers -Plng & Reg Accts
Witness Name: Sandra K. Hrna

	2016	2017	2018	2019	2019 Revised	2019 Variance
Labor:	3837	3836	4036	4036	4036	0
Non-Labor:	128	99	47	47	47	0
NSE:	0	0	0	0	0	0
FTE:	35.3	36.8	38.8	38.8	38.8	0

- Capital Expenditures:

									Revised	Revised Forecasts		
Project_ID	Budget_Code	Project_Sub_Name	Witness_Name	Repair Allowance	Phased_In_Pct	AFUDC	AFUDC_CWIP	CWIP	In_Service_Dates	2017	2018	2019
1	000060.001	Generation Capital Tools & Test Eqpt.	Baerman, D.	N	1.0000	-	-	-		275	275	275
10	002020.001	ELECTRIC METERS & REGULATORS	Colton, A.	Y	1.0000	-	-	-		4,065	4,108	4,596
100	08729A.001	Alternative Energy Systems	Tattersall, R.	N	0.1546	1	2	499		2,625	2,814	5,724

PG&E – Example of User-Friendly Interface

- Escalation:

EscGrp	CostElement	Year	EscRate	EscFactor
OM	LAB	2017	0	1.00000
OM	LAB	2017RA	0	1.00000
OM	LAB	2018	0.033	1.03300
OM	LAB	2019	0.0326	1.06668
OM	LAB	2020	0.0326	1.10145
OM	LAB	2021	0.0326	1.13736
OM	LAB	2022	0.0326	1.17443
ED	MAT	2017	0	1.00000
ED	MAT	2017RA	0	1.00000
ED	MAT	2018	0.013	1.01300
ED	MAT	2019	0.014	1.02718
ED	MAT	2020	0.019	1.04670
ED	MAT	2021	0.018	1.06554
ED	MAT	2022	0.018	1.08472

- Capital Expenditures:

i. Change Costs and/or Operative Date in a Capital Planning Order:

Tab: Adjustments

5675	Counter Position													
TRUE	Total Overriden Monthly Adjustments (BS-->BW) + Annual Adjustments (BY-->CC) = Total Monthly Adjustments (Col J-->BR)													
TRUE	Reconciled to data source tabs: Capex, Adjustments, Capex_w Adj													
TOTAL									0	(400)	0	0	0	0
	Update Results									Annual Adjustments				
Order	Description	MWC	Asset Class	Func	UCC	CGIF	Operative Date		Dec 2014 CWIP	2015	2016	2017	2018	2019
5755439	SAN JOSE A: REPL REL ON TB 1<2<&3	9		EDP	301	F	5/1/2015			(400)				
5755444	SPAULDING PH1: INSTALL: D-SCADA	9		EDP	301	F	8/1/2015							
5755449	Tivy Valley: Install D-SCADA on CB1106 &	9		EDP	301	F	9/1/2016							
5755450	Vineyard: Replace RTU	9		EDP	301	F	[illegible]							
5755452	West Point PH: Install D-SCADA on Bk< Fe	9		EDP	301	F	[illegible]							
5755453	WESTPARK INSTALL D SCADA 09	9		EDP	301	F	12/1/2014							
5755455	WILSON SUB: INSTALL: D-SCADA	9		EDP	301	F	6/1/2017							
5755456	WISE PH: INSTALL: D-SCADA	9		E										
5755524	09-BIG BASIN - REPLACE PDAC ON BANK	9		E										
5755527	HERDLYN SUB: INSTALL: D-SCADA	9		EDP	301	F	7/1/2018							
5755530	NC_EUREKA STA E: INST D-SCADA-BK 1	9		EDP	301	F	6/1/2016							

Change Project Operative Dates

Adjust Project Amount

The user can adjust any of the **project plan amounts** and change the **operative dates**.

- O&M:

MWC Expense (In Thousands of Nominal and Constant Dollars) - GRC Test Year

(Note: Button will clear filters for current tab, calculate changes, and refresh pivot tables/external links)

Update data

Click button after Make changes to refersh model

(Calculation may take longer if other Excel files are open)

RowNo	Year	ExhCh	MWC	Bus_Are	Acct	MNEM	FuncGrp	EscGrp	UCC	CostElem	CostElem	SortCE	Nominal$	Subtotal Chap/MWC - Exclude Rev Nominal SubTotal	NominalAlloc	(Enter Negative Amt in green cell) NominalAdj	Alloc
241	2020	004-008	GA	ED	588	DT	ED	ED	301	LAB	Labor	1	407.50	17,771.54	2.29%	-17,771.54	
242	2020	004-008	GA	ED	588	DT	ED	ED	301	MAT	MAT	1	320.95		1.81%		
243	2020	004-008	GA	ED	593	DT	ED	ED	301	LAB	Labor	1	1,552.70		8.74%		
244	2020	004-008	GA	ED	593	DT	ED	ED	301	MAT	MAT	1	15,463.19		87.01%		
245	2020	004-008	GA	ED	598	DT	ED	ED	301	LAB	Labor	1	52.60		0.30%		
246	2020	004-008	GA	ED	598	DT	ED	ED	301	MAT	MAT	1	-25.41		-0.14%		
247	2020	004-008	GA	ED	456	Rev	Rev	Rev	301	Rev	Rev	3	-4,183.50		0.00%		
										TOTAL			2,891,298.20	2,926,439.81		0	
													MWC O&M RO Input Adjustment excluding Burden & PR Tax:				
										Less: Burden			0.00				
										Less: Revenue			-35,141.62	35,141.62	0.00		
										MWC RO Input			2,926,439.81				
										Less: MWC A&G RO Input			473,660.84				
										MWC O&M RO Input			2,452,778.97				

Uniform RO Model Format & Structure

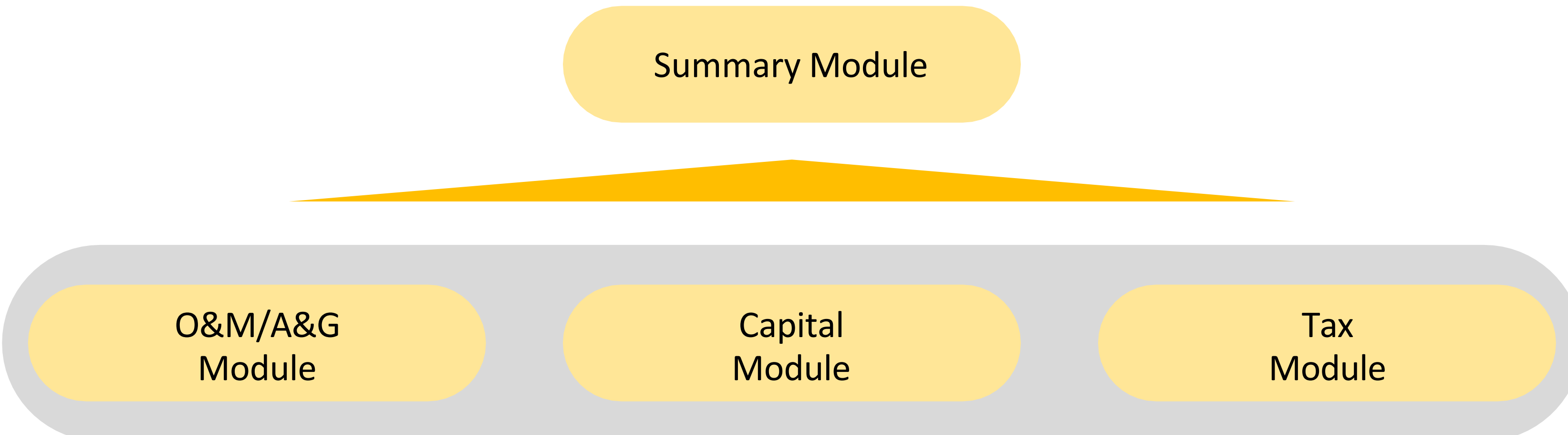
Uniform RO Model Format & Structure

IOU RO Models share similar "DNA"

- Foundational structure is consistent across IOUs
  - O&M/A&G, Capital, Tax, and Summary modules
  - User Guides
  - Data flow diagrams
  - Processing sequence
  - Identification of inputs that can be changed
- IOU RO Model Workshops following filing of Application
- Working sessions with PAO and Energy Division
- Revenue requirement calculation:
  - PG&E: Gross-up factors
  - SCE, SDG&E/SoCal Gas: Goal Seek

RO Model format and structure is tailored towards each IOUs' internal business requirements. However, IOU RO Models share similar foundational principles to bridge a generally uniform "look and feel" across IOUs.

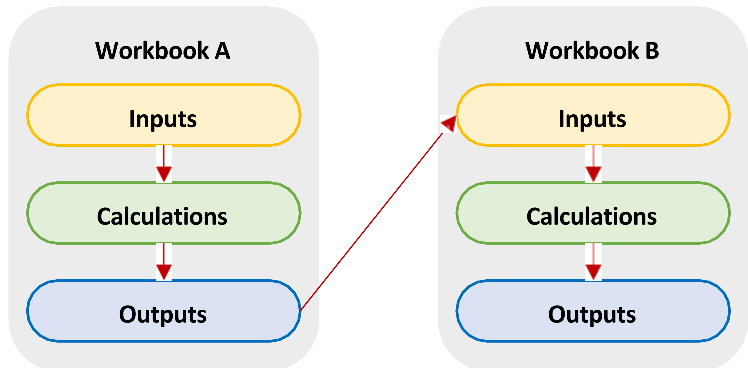
RO Model Overview



- The RO Model consists of interdependent modules
- Any changes made to the O&M, Capital, and Tax modules flow to the Summary module
- The Summary module uses information from the O&M, Capital, and Tax modules to calculate Revenue Requirement

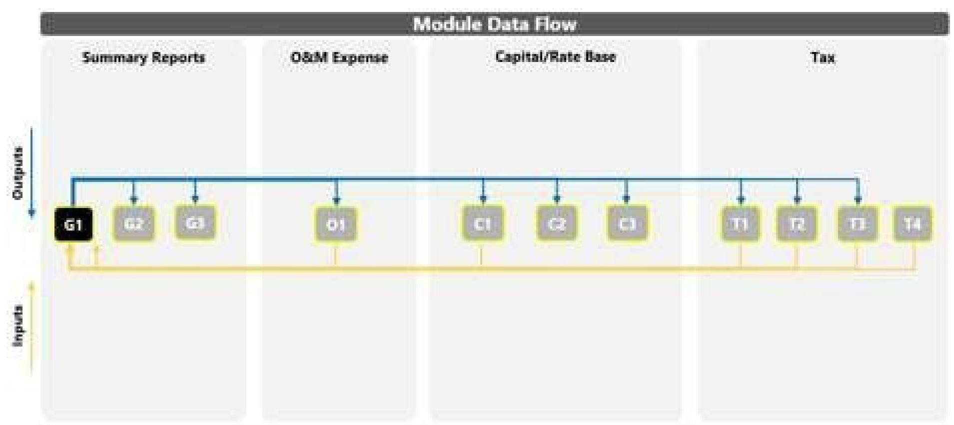
SCE RO Model Architecture | Data Interaction

How Data Flows Within and Between Workbooks



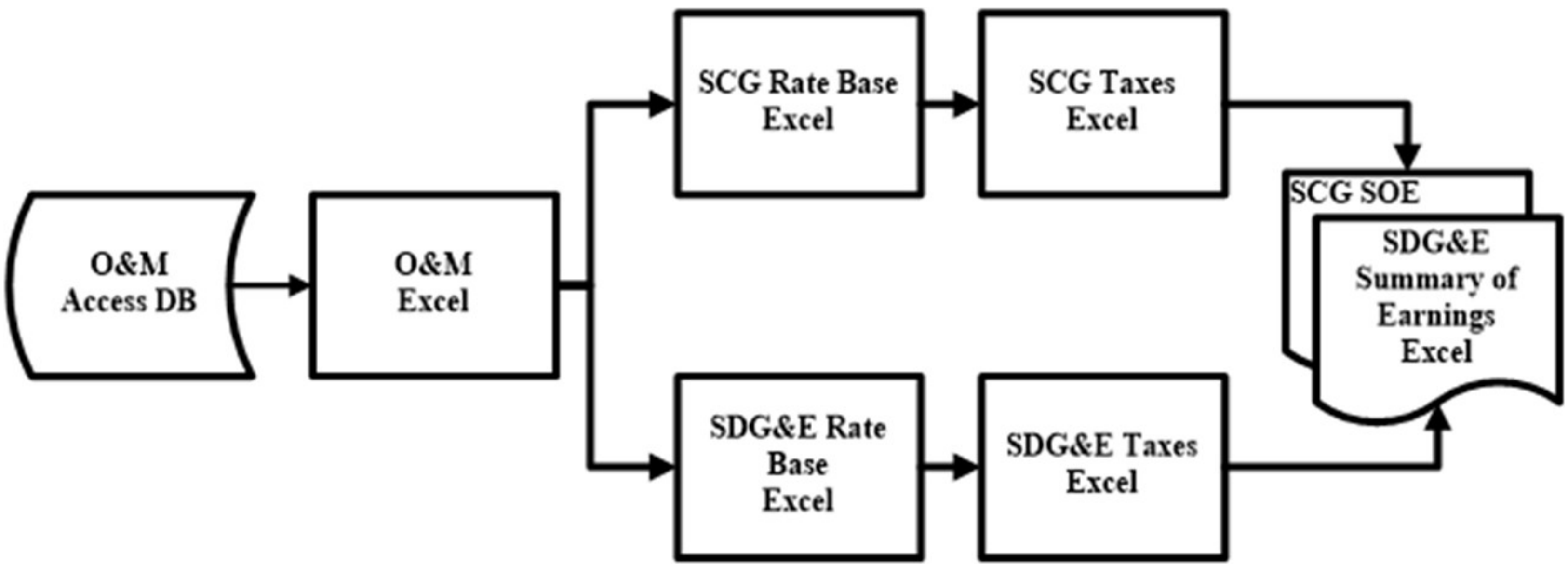
- **Inputs** centralization improves transparency and highlights workbook's main drivers
- **Calculations** only use data within workbooks
- **Outputs** centralization provides insights into the flow of data out of workbooks

How RO Model Workbooks Interact

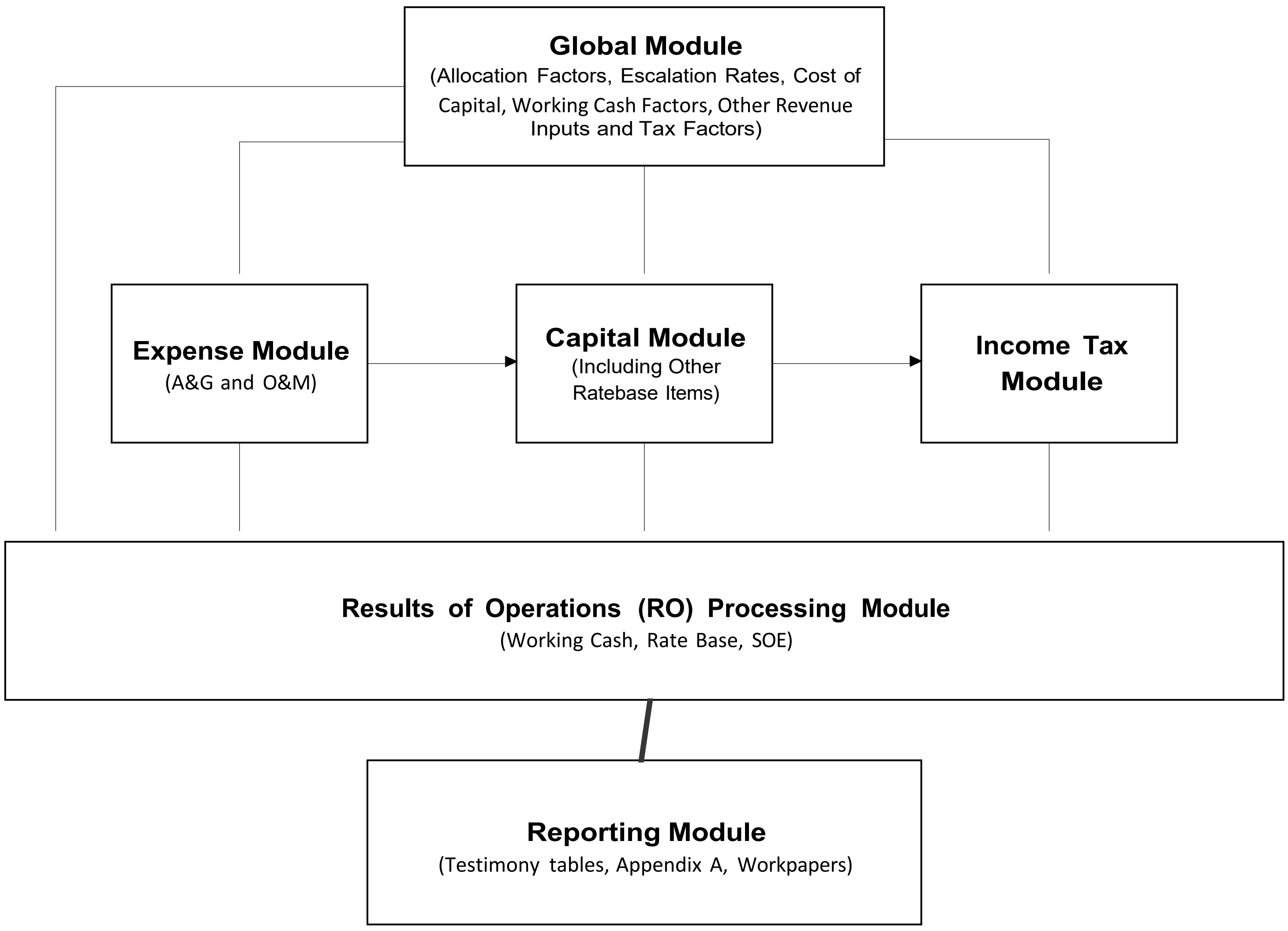


- **Linear Flow** of information enhances interaction between workbooks
- **Model Connections** are controlled within *Inputs* and *Outputs* sections of workbooks

SDG&E/SoCalGas RO Model Architecture | Data Interaction



PG&E RO Model Architecture | Data Interaction



RO Model – SCE Processing Sequence

Legend

File Name	ID
O&M Dashboard	O1
Capital Inputs	C1
Rate Determination Schedule	C2
Other Rate Base Items	C3
GRC	G1
GRC Appendices	G2
Reporting Dashboard	G3
DEPR & DFIT	T1
Income Taxes	T2
Payroll Taxes	T3
Property Taxes	T4

RO Model Cycle and Workbook Sequence

Refresh cycle sequence

Refresh workbook sequence

O&M	Capital 01	Tax	Tax Loop	O&M FFU	Capital FFU	Tax FFU	Report	Security
G1	C2	G1	T4	O1	C1	T4	G1	C1
O1	C1	T3	T2	G1	C3	T2	G2	C3
T3	C3	T4	O1		C1	O1	G3	C2
O1	T2	T2	G1		G1	C1	G1	T1
G1		O1	C1			C3		T2
		G1	C3			C1		T3
		C3	C1			T1		T4
		C1	T1			G1		G2
		T1	G1					G1
		G1	T2					O1
			G1					

RO Model – SDG&E/SoCalGas Processing Sequence

Sequence #1 - Refresh Sequence					
ID	File Name	Module	ID	File Name	Module
0	omUSSCalculation.xlsb	O&M	23	rbSDGEDataInput.xlsb	RateBase
1	rbSCGBilledCap.xlsb	RateBase	24	rbSDGEData.xlsb	RateBase
2	rbSDGEBilledCap.xlsb	RateBase	25	rbSDGEAdds.xlsb	RateBase
3	sum.xlsb	SOE	26	rbSDGEPlantSum.xlsb	RateBase
4	omAllLoadRODb.xlsb	O&M	27	rbSDGETax.xlsb	RateBase
5	omAllCalculation.xlsb	O&M	28	taxSDGEDeferred.xlsb	Tax
6	om.xlsb	O&M	29	rbSDGETotals.xlsb	RateBase
7	omAllCalculation.xlsb	O&M	30	taxSDGE.xlsb	Tax
8	om.xlsb	O&M	31	taxSDGEDeferred.xlsb	Tax
9	taxSCG.xlsb	Tax	32	sum.xlsb	SOE
10	rbSCGDataInput.xlsb	RateBase	33	omAllLoadRODb.xlsb	O&M
11	rbSCGPlt1.xlsb	RateBase	34	omAllCalculation.xlsb	O&M
12	rbSCGPlt2.xlsb	RateBase	35	om.xlsb	O&M
13	rbSCGPlt3.xlsb	RateBase	36	sum.xlsb	SOE
14	rbSCGPlt4.xlsb	RateBase	37	rbSCGTotals.xlsb	RateBase
15	rbSCGSharedAsset.xlsb	RateBase	38	rbSDGETotals.xlsb	RateBase
16	rbSCGPlantSum.xlsb	RateBase	39	wcSCG.xlsb	Working Cash
17	taxSCGDeferred.xlsb	Tax	40	wcSDGE.xlsb	Working Cash
18	rbSCGTotals.xlsb	RateBase	41	taxSCG.xlsb	Tax
19	rbSCGSharedAsset.xlsb	RateBase	42	taxSDGE.xlsb	Tax
20	taxSCG.xlsb	Tax	43	rptSummary.xlsb	SOE
21	taxSCGDeferred.xlsb	Tax	44	Sum.xlsb	SOE
22	taxSDGE.xlsb	Tax			

Sequence #2 - Net Operating Loss Calculation		
ID	File Name	Module
0	taxSCGDeferred.xlsb	Tax
1	rbSCGTotals.xlsb	RateBase
2	rbSCGSharedAsset.xlsb	RateBase
3	taxSCG.xlsb	Tax
4	taxSCGDeferred.xlsb	Tax
5	taxSDGEDeferred.xlsb	Tax
6	rbSDGETotals.xlsb	RateBase
7	taxSDGE.xlsb	Tax
8	taxSDGEDeferred.xlsb	Tax
9	sum.xlsb	SOE
10	rbSCGTotals.xlsb	RateBase
11	rbSDGETotals.xlsb	RateBase
12	wcSCG.xlsb	Working Cash
13	wcSDGE.xlsb	Working Cash
14	taxSCG.xlsb	Tax
15	taxSDGE.xlsb	Tax
16	rptSummary.xlsb	SOE
17	Sum.xlsb	SOE

RO Model – PG&E Processing Sequence

PG&E RO Model Workbook Sequence		
Sequence	**Filename**	**Module**
1	EscFactor_Revised.xlsx	Global
2	labor_alloc_factor.xlsx	Global
3	GRCWMCExpense.xlsb	Expense
4	GRCAGExpense.xlsb	Expense
5	Global.xlsb	Global
6	InputsExpenseRO.xlsx	Expense
7	CapitalModel.xlsb	Capital
8	OtherRatebase.xlsb	Capital
9	InputsCapitalRO.xlsx	Capital
10	CapResOutputToTax.xlsb	Capital->Tax
11	Tax_Unbundling.xlsb	Tax
12	Simplified_Tax.xlsb	Tax
13	Tax_Summary.xlsb	Tax
14	InputsTaxRO.xlsx	Tax
15	GRCROModel.xlsb	RO Processing Module
16	ROTestimonyTables.xlsx	Reporting Module
17	RO_AppendixA.xlsx	Reporting Module
18	RO_Workpapers.PDF	Reporting Module

Working Relationship with ALJ & Energy Division

RO Modeling Process at the CPUC

- Energy Division staff support the ALJ in a GRC
- Under a Non-Disclosure Agreement, ED staff works with IOU to incorporate draft PD adjustments in the RO Model
- Liaison for ALJ and IOU modeler – PD interpretations
- Collaborate with IOU modeler to produce workpapers for every PD adjustments

Working Relationship with ALJ & Energy Division

- Decision language: "workshops would provide an opportunity for the utilities to explain their perspectives and develop a single approach to their working relationship with the ALJ and Energy Division staff, to be used by all utilities in all GRCs going forward. This would improve the predictability of this stage of preparing the PD."
- Continue process of utility expert supporting CPUC throughout PD development process, as requested by CPUC.
- Early engagement with IOUs for a modified process:
  - Working sessions to gain familiarity with IOU RO model
  - Energy Division creates templates and workpapers to support modeling inputs
  - IOUs conduct initial modeling
  - IOUs and Energy Division review templates, workpapers, and modeling inputs
  - IOUs support Energy Division to validate modeling results
- Update the Results of Operations Modeling Procedures, Protective Order, and Certificate of Compliance to allow for remote modeling

Discussion

Next Steps and Wrap Up

Wrap Up

Please send comments to: kris.vyas@sce.com and gelila.berhane@cpuc.ca.gov.

Comments and report schedule:
Workshop Comments: November 25, 2020
Draft Report: December 7, 2020
Draft Report Comment: December 14, 2020
Final Report: December 21, 2020

Workshops #1 and #2 reports are available at:

https://www.cpuc.ca.gov/General.aspx?id=6442454678

13. Appendix B: Post Workshop Comments

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities.	R.13-11-006

JOINT COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SOUTHERN CALIFORNIA GAS COMPANY (U 904-G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), AND PACIFIC GAS AND ELECTRIC COMPANY (U 39-M) ON RATE CASE PLAN WORKSHOP NUMBER 3

CLAIRE E. TORCHIA KRIS G. VYAS Attorneys for SOUTHERN CALIFORNIA EDISON COMPANY 2244 Walnut Grove Avenue Post Office Box 800 Rosemead, California 91770 Telephone: (626) 302-6613 E-mail: Kris.Vyas@sce.com	SHARON L. COHEN Attorney for SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY 8330 Century Park Court, CP32D San Diego, California 92123 Telephone: (619) 696-4355 Facsimile: (619) 699-5027 E-mail: slcohen@semprautilities.com
MARY GANDESBERY Attorney for PACIFIC GAS AND ELECTRIC COMPANY 77 Beale Street, B30A San Francisco, California 94105 Telephone: (415) 973-0675 Facsimile: (415) 973-5520 E-mail: Mary.Gandesbery@pge.com	

Dated: **December 14, 2020**

Joint Comments of Southern California Edison Company (U 338-E), Southern California Gas Company (U 904-G), San Diego Gas & Electric Company (U 902-M), and Pacific Gas and Electric Company (U 39-M) on Rate Case Plan Workshop Number 3

Table of Contents

Section	Page

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities.	R.13-11-006

JOINT COMMENTS OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SOUTHERN CALIFORNIA GAS COMPANY (U 904-G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), AND PACIFIC GAS AND ELECTRIC COMPANY (U 39-M) ON RATE CASE PLAN WORKSHOP NUMBER 3

I.

INTRODUCTION

In accordance with guidance provided by the Staff of the California Public Utilities Commission ("Commission"), the Investor-Owned Utilities ("IOUs") Southern California Edison Company ("SCE"), Southern California Gas Company ("SoCalGas"), San Diego Gas & Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E") (collectively, the "IOUs") respectfully submit their joint comments[1] regarding the November 19, 2020 General Rate Case Workshop ("Workshop 3"). Workshop 3 was conducted pursuant to the Commission's recent decision ("D") in Rulemaking ("R.") 13-11-006 (the "Rate Case Plan" or "RCP" Rulemaking), D.20-01-002 (hereinafter referred to as the "RCP Decision").

The workshop scope encompassed five topics, followed by open discussion:

---

[1] Pursuant to Commission Rule of Practice and Procedure 1.8(d), counsel for SCE confirms that PG&E, SoCalGas, and SDG&E have authorized SCE to file these joint comments on their behalf.

- Introduction to Results of Operations (“RO”) Model
- Standard Format for Summary of Earnings
- User-Friendly Interface
- Uniform RO Model Format & Structure
- Working Relationship with Administrative Law Judge (“ALJ”) & Energy Division

The IOUs reiterate their commitment to continuing assessment of their RO Models to identify prudent and practical opportunities to align across IOUs, to foster simplicity and transparency and to promote a more user-friendly experience. The IOUs intend to continue to consult and collaborate with each other and remain open to feedback from other parties on reasonable opportunities to align aspects of the models, improve the user experience, and carry out other ideas for overall improvement.

With the exception of one item (which is discussed below), the IOUs believe no formal regulatory ruling or activity is necessary in order to implement the concepts introduced during Workshop 3; areas for possible alignment of models have already been identified and shared at Workshop 3. The IOUs agreed to explore the concepts that were introduced during Workshop 3 and, if feasible, implement the modifications in the IOUs’ next general rate case (“GRC”) Applications. Consistent with other model changes, these modifications will be communicated in a fully transparent manner to Energy Division Staff and any interested stakeholder in the applicable GRC proceeding.

These Workshop 3 comments are limited to the topics raised by non-IOU participants during the workshop, and otherwise do not repeat points that IOU representatives presented that did not garner further questions or comments during the workshop.

II.

DISCUSSION

A. The IOUs Do Not Recommend That Confidential Information Be Disclosed During the Course of Development of the GRC Proposed Decision

During the workshop, SCE, on behalf of the IOUs, discussed how the IOUs support Commission Staff and ALJs in incorporating draft Proposed Decision ("PD") adjustments in the RO model. This activity is conducted pursuant to a strict non-disclosure agreement ("NDA"). Under the NDA, the utility expert(s) assisting the Commission may not disclose the nature of their work to external parties, or internally within their own utility. Following SCE's workshop presentation, TURN requested that the RO modeling conducted in preparation of a PD be as transparent as possible. The IOUs agree with the spirit of this comment and share in the desire to be as transparent as possible.

However, it would be inappropriate to share RO modeling information during the period that utility staff is working with the Commission to develop a PD. This period involves the Commission asking the utility's personnel to take information that Commission personnel have identified or selected, and run or process it through modeling so that the Commission personnel can assess outcomes. The utility's efforts assist the Commission in developing a PD. Transparency under these circumstances would infringe on the Commission's decision-making process, by disclosing its "in progress" thought processes and analysis before the PD is approved for issuance. It may inadvertently cause confusion if information is shared, but then changes substantially as further work occurs on the PD. The IOUs are also concerned by the risk of disclosing market-sensitive information in a piecemeal fashion or prematurely before it has been properly checked, validated, and then approved by Commission leadership.

The current protocols call for strict non-disclosure except as between the designated utility expert(s) and the Commission. The IOUs strongly feel that any change to the current protocols in this regard must originate solely from the Commissioners and be clearly communicated after notice and a full opportunity to be heard. The IOUs do not recommend changing the timing and nature of disclosing (or not disclosing) RO modeling information while the PD is still under development.

B. <u>The IOUs Encourage the Commission to Authorize Remote PD Modeling as the Default</u>

In general, the IOUs do not believe the proposals discussed during Workshop 3 require or warrant any action from the Commission, as the IOUs are committed to exploring the opportunities discussed during the workshop for purposes of possible future alignment. The IOUs are also committed to sharing any changes in a transparent manner.

There is one exception to this IOU viewpoint. One proposal that appears to warrant an Order from the Commission involves updating the Results of Operations Modeling Procedures, Protective Order, and Certificate of Compliance to allow for remote modeling. The recent Ruling in the PG&E GRC can be used as a template.[2] During Workshop 3, SCE noted the expense and burden associated with the Southern California utility experts needing to travel to and stay in San Francisco for several weeks or more at a time to assist in the PD RO modeling. SCE also pointed out the positive environmental impact of avoiding this extended travel.

In response to questions from Energy Division Staff, PG&E noted that the remote modeling undertaken in collaboration with Energy Division during the COVID-19 pandemic has proceeded smoothly and without incident. PG&E and Energy Division held regular working calls, and PG&E stated it was able to securely share screens and files, and confidentially store those files as well.

Energy Division Staff appeared receptive to the IOU proposal to move to a default of remote modeling in support of PD development, with utility experts only traveling to Commission offices if specifically directed to do so by the ALJs or Assigned Commissioner

[2] Administrative Law Judges' Ruling Adopting Amended Confidential Modeling Procedures, issued August 13, 2020.

presiding over a given GRC proceeding. As such, the IOUs respectfully urge Energy Division Staff to discuss this proposal within the Commission to ascertain if the Commission can issue guidance that authorizes such a change on a going-forward basis.

III.

CONCLUSION

The IOUs appreciate the opportunity to present to, and collaborate with, other stakeholders during Workshop 3. The IOUs also thank the Commission for the opportunity to provide written comments. The IOUs look forward to working toward greater alignment across the RO models where practical, and engaging in further discussions with all interested parties regarding efficiencies that can be reasonably achieved in GRC proceedings.

Respectfully submitted,

CLAIRE E. TORCHIA
KRIS G. VYAS

/s/ Kris G. Vyas
By: Kris G. Vyas

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6613
E-mail: Kris.Vyas@sce.com

December 14, 2020

GENERAL RATE CASE PLAN
WORKSHOP #4 REPORT

Standardization of RAMP Filings

March 11, 2021

TABLE OF CONTENTS

1. Executive Summary

On February 9, 2021, Energy Division hosted the fourth in a series of workshops to explore standardizing the organization and format of General Rate Case (GRC) and Risk Assessment Mitigation Phase (RAMP) filings for the large California energy utilities. The workshops were ordered in Decision (D.) 20-01-002, which modified the Commission's Rate Case Plan (RCP) for large energy utilities. The objective of the workshops is to further explore and develop proposals to increase the efficiency of GRC proceedings. The scope of the fourth workshop was to better integrate the RAMP into the GRC and the Risk Spending Accountability Report (RSAR) as well as standardize the organization and format of GRC and RAMP filings. In addition to Commission staff, identified workshop attendees included Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), the Public Advocates Office (Cal Advocates), The Utility Reform Network (TURN), Protect Our Communities Foundation (PCF), Commissioner Rechtschaffen and Administrative Law Judge(ALJ) Fogel.

The workshop scope included six main subject areas followed by open discussion:

- Risk mitigation and cost presentation standards
- Merger of the RSAR and other accountability reports
- Potential redundancies between RAMP, GRC, and RSAR filings
- GRC settlements and the relationship with RAMPs and RSARs
- RCP requirement updates
- RAMP clarifications and refinements

The investor-owned utilities (PG&E, SCE, SDG&E, and SoCalGas; collectively "IOUs") presented on all topics except for introductory remarks and a presentation by Cal Advocates regarding RCP updates and RAMP clarification and refinement. Energy Division, Cal Advocates, TURN, and ALJ Fogel all participated in the discussion during the workshop. Below is a high-level summary of the workshop discussion.

A draft version of this workshop report was circulated for comment on February 25, 2021. Informal comments were submitted on March 4, 2021 by Cal Advocates, TURN, and PCF (March 4 Post-Workshop Comments).

The March 4 Post-Workshop Comments of Cal Advocates and TURN were clarifying in nature. Cal Advocates also provided an additional recommendation, which was not discussed at the workshop, for RAMP applications to include and consider the results of utility Climate Change Vulnerability Assessments ordered in D.20-08-046. PCF did not provide comments or participate in the discussion during the workshop and instead submitted written positions in its March 4 Post-Workshop Comments. All March 4 Post-Workshop Comments are reflected in this report in a manner consistent with the purpose of this report to summarize the discussions held at the workshop and provide a neutral record of the topics of discussion.

2. Introduction

On February 9, 2021, Energy Division (ED), in concert with Safety Policy Division (SPD), hosted the fourth in a series of workshops related to the GRC filings of the large California energy utilities. The workshops were ordered in D.20-01-002, which modified the Commission's RCP for the large energy utilities. The objective of the workshops is to further explore ideas to standardize GRC filings and streamline the process in order to increase the efficiency of GRC proceedings. The scope of the fourth workshop was to discuss the standardization of the RAMP filings of the IOUs. The workshop was facilitated by ED with support from SPD as well as SoCalGas and SDG&E. This workshop report summarizes the discussions held during the February 9, 2021 workshop.

3. Background

On January 16, 2020, the Commission issued D.20-01-002 (the "Decision Modifying the Commission's Rate Case Plan for Energy Utilities" in Rulemaking (R.) 13-11-006), referred to herein as the "RCP Decision." The RCP Decision adopted changes to the Rate Case Plan for large California energy utilities to enable the Commission to conduct GRC proceedings more efficiently, including modifications to the GRC procedural schedule and extending the GRC cycle for each utility from three years to four years.[1] R.13-11-006 was closed upon the Commission adoption of the RCP Decision.

The RCP decision also ordered a series of workshops to explore and develop proposals to increase the efficiency of GRC proceedings. The basic purpose of the series of the workshops is to see if various matters common to all GRCs can be redesigned and consistently applied to make the proceedings more efficient for the Commission and parties alike. Based on the number of workshop topics, ED identified four workshops (and associated suggested timing) and invited parties to provide feedback on the scope of each workshop:

1. Workshop No. 1 - Stipulated Terms / Rebuttable Presumptions / Standardized Attrition Year Ratemaking – September 4, 2020
2. Workshop No. 2 - Standardization of GRC Filings – October 7, 2020
3. Workshop No. 3 - Results of Operations (RO) Model Uniformity – November 19, 2020
4. Workshop No. 4 - Standardization of RAMP Filings – February 9, 2021

The IOUs are supporting ED staff in facilitating the RCP workshops, and an IOU has been designated for each workshop. The RCP Decision also requires that no later than 30 days after the conclusion of the workshop, the designated IOU shall submit a report to the Directors of the Energy Division and Safety and Enforcement Division with copies served on the service list of R.13-11-006 summarizing the workshop and any agreed-upon proposals.

Subsequently, in July 2020, the Commission opened a new Rulemaking, R.20-07-013, to address Safety Model Assessment Proceeding (S-MAP) long-term roadmap issues and priorities. The

---

[1] To transition to this change, the Test Year 2019 GRC cycle for SDG&E and SoCalGas was extended to a five-year cycle.

Rulemaking was split into two Phases. Phase 1 was divided into four tracks and Phase 2 was divided into two tracks with each of the tracks being clearly and discretely defined.[2] Phase 1/Track 3 concerns "Refining RAMP and Related Procedural Requirements" and is further divided into three parts:

a. Should the Commission provide further direction to align terms, definitions, and processes across RAMP and GRC proceedings, Risk Spending Accountability Reports (RSARs) and the Risk-Based Decision-Making Framework (RDF) to enable improved tracking of safety expenditures and related risk reductions? If so, should the guidance address:

    i. How risk mitigation and related administrative or other costs, or investments, should be presented and defined in RAMP and GRC applications, and the RSARs, to better enable comparisons of proposals over time and to distinguish such costs from non-RAMP related costs;

    ii. Potential redundancies between RSAR and related safety accountability reports and possible ways to integrate safety accountability reporting across proceedings;

    iii. Potential redundancies between RAMP, GRC, and RSAR filings; and

    iv. RAMP and RSAR requirements for GRC proceedings resolved via Settlement Agreement?

b. Should Rate Case Plan requirements be updated to reflect any clarifications adopted in this proceeding?

c. Other potential RAMP clarifications or refinements as needed, including those identified in D.20-01-002.

On January 13, 2021, ED sent a save the date via email for the workshop to the service lists of R.13-11-006 and R.20-07-013. There, ED stated that because the topics identified for the RCP Workshop No. 4 and the S-MAP Phase 1/Track 3 cover the same issues, ED determined that they are functionally the same and merged the RCP Workshop #4 with the S-MAP Track 3 Workshop. In preparation for the workshop, on January 22, 2021, ED issued a preliminary agenda for the consolidated workshop. The following is the combined RCP Workshop #4 and the S-MAP Track 3 Workshop summary prepared by SoCalGas and SDG&E, who were the leading IOU for this workshop.

4. Workshop

ED held the public workshop virtually via a recorded WebEx session on February 9, 2021. Due to the state's public health order in response to the COVID-19 pandemic, there was no in-person attendance. ED sent a notice of the workshop to the service lists of R.13-11-006 and

---

2 *See* R.20-07-013 Scoping Memorandum issued on November 2, 2020 at pages 4-9.

R.20-07-013. The public workshop notice was posted on the Commission's Daily Calendar and website.

According to the ED's January 22 preliminary agenda (at page 1), the workshop is mandated by both D.20-01-002 and R.20-07-013. Pursuant to these Commission orders, the purpose of the workshop is to "[b]etter integrate RAMP into the GRC and GRC-related reporting into the RSAR" and "[s]tandardizing the organization and format of GRC and RAMP filings." The workshop, was scheduled from 11:00 am – 4:00 pm, and included the agenda below with topics prompted from ED's January 22 preliminary agenda:

- Introduction and Purpose
- Lessons Learned and Topic Overview
- Topic 1: Track 3.a.i – Risk Mitigation and Cost Presentation Standards
- Topic 2: Track 3.a.ii – Merger of the RSAR and Other Accountability Reports
- Topic 3: Track 3.a.iii. – Redundancies Between RAMP, GRC, and RSAR
- Topic 4: Track 3.a.iv. – GRCs Resolved by Settlement Agreement
- Topic 5: Track 3.b./c. – Refining RAMP and GRC Procedural Requirements
- Topic 6: Track 3.b. – Updates to RCP Requirements
- Topic 7: Track 3.c. – RAMP Clarifications and Refinements
- Discussion / Q&A

The agenda topics reference and align with the tracks set forth in the S-MAP Rulemaking Scoping Memorandum.

ED staff began the workshop by discussing the workshop logistics and background and provided an overview of the workshop's agenda and goals. Formal presentations were then made by the IOUs' representatives and Cal Advocates. After each formal presentation, attendees had an opportunity to comment and ask questions.

5. ED and SPD Lessons Learned

The workshop began with ED providing opening remarks, and then they transitioned to lessons learned. For ED's lessons learned, they described that while the RDF was being developed in the first S-MAP, parties to the proceedings were partially informed of how risk-related decisions were made but the general public was not particularly informed. With the approval of the S-MAP settlement agreement, adopted in D.18-12-014, ED explained that there has been a noticeable uptick in interest and understanding on how the Commission has made its decisions.[3] Accordingly, ED stated that having consensus amongst the parties has been very helpful in making the RDF process work. ED would like to see more consensus to further drive the decision-making process. ED also noted that the RAMP and GRC filings do not have the same level of detail when describing programs and mitigations resulting in additional complexities when evaluating decision-making in RSARs. ED emphasized the desire for

[3] In its March 4 Post-Workshop Comments, PCF notes its belief that "increased interest in risk-related decision-making likely resulted from the utilities' 2019 Wildfire Mitigation Plans," citing D.19-05-036, p. 29, fn. 42.

reporting to be expressed in work units, but recognized that, in some instances, there is no perfect unit of work and standardizing units may be limited based on the organization of each utility's GRC. That said, when there is an absence of units it is difficult for ED to evaluate and to determine if everything is being done properly in the context of RSARs. Similarly, ED has found that standardization of the discovery process is hampered because the IOUs are of differing sizes and are organized differently. ED has also stated that programs and mitigations are mismatched and hopes that the workshop process can develop definitions for programs and mitigations. ED noted that the Commission has not been using Risk Spend Efficiency (RSE) data when considering the funding of risk reducing activities and commented that RSEs can potentially be useful in that discussion. Lastly, ED concluded that modeling results are typically updated from the first "runs" presented in the RAMP prior to a utility submitting the GRC. ED acknowledges that RAMP cost estimates may not be accurate as they are calculated several years in advance and RAMP mitigations tend to be aspirational. The changes between RAMP to GRC may be confusing from the public's perspective when reviewing each filing. However, the extensive review process in the GRC is designed to consider any differences in the activities described in the RAMP and the GRC. In its March 4 Post-Workshop Comments, PCF notes that the "Energy Division's sentiment contradicts numerous Commission decisions which explicitly require quantification of risk reduction activities so that risk reduction activities may be prioritized based on their cost-effectiveness." PCF also states that the "Commission found in 2016, 'Without quantifying risk reduction, no meaningful ranking, prioritization or optimization of risk mitigations is possible, and the Commission's goals and processes set forth in D.14-12-025 are compromised.'"[4]

SPD also provided their "lessons learned" feedback based on its experience with SCE's recent GRC (Test Year (TY) 2021). SPD acknowledged and appreciated that SCE took SPD's RAMP feedback and incorporated it into the GRC, including a roadmap from the RAMP to the GRC making testimony and hearings much more productive by providing a baseline and a benchmark as reference. SPD also noted that SCE's modeling capability was greatly improved between the RAMP and the GRC and that consideration should be given to whether this model could become the template for other GRC applications.

6. Topic 1: Track 3.a.i – Risk Mitigation and Cost Presentation Standards

6.1 Staff Proposal

ED proposed that the IOUs present unified methods for identifying RAMP mitigation in the GRC, noting that RAMP is often more detailed. ED also proposed that the IOUs commit to presenting activities in the same manner in both the GRC and RAMP. While there has been movement in making GRC and RAMP more consistent, there is still more to do. Lastly, ED proposed developing guidelines to: (1) identify common elements between RAMP and GRC and (2) match RAMP information to the subsequent GRC.

---

4 Citing to D.16-08-018, Interim Decision Adopting the Multi-Attribute Approach (Or Utility Equivalent Features) and Directing Utilities to Take Steps Toward a More Uniform Risk Management Framework (August 18, 2016), p. 182 (Finding of Fact 33).

6.2 IOU Presentation – Challenges of RAMP Standardization and RAMP to GRC Integration

On behalf of the IOUs, SCE presented slides explaining that standardization of RAMP faces similar challenges as GRC standardization. SCE noted that stakeholders did not raise any concerns at the RCP Workshop #2, during which time parties extensively discussed how GRCs are organized to mirror the organization of each IOU's business structure. In its March 4 Post-Workshop Comments, PCF states, "No conclusion should be drawn regarding concerns not raised at RCP Workshop #2. Workshop participants may not have had the ability or opportunity to raise their concerns at the workshop, and not all parties to R.20-07-013 were participants in R.13-11-006." Notwithstanding this viewpoint, the IOUs have not received feedback that IOU organizational differences present any barriers to assessing utility showing or finding items within the showing.

Further, SCE stated that it is difficult to standardize RAMPs across the IOUs because each is organized differently, has different business lines, enterprise risks, proposed controls, mitigations, and funding approvals. SCE also stated that the mechanism to compare the RAMP to the GRC is tied to unique accounting systems for each of the IOUs. For example, SCE, other than a small component, has no gas business, which is a fundamental difference between SCE and SDG&E, SoCalGas, and PG&E. This differences in business structures leads to differences in how the IOUs organize their GRC presentations to make it the most visible, transparent and effective according to their own business.

Lastly, the IOUs agree that presentation in RAMP should be generally consistent with the IOU's GRC to the extent reasonably possible. But funding is not sought in RAMP, and reasonableness is not determined. The granularity, level of detail/workpapers, and justification presented in RAMP does not appear to be fully aligned with the GRC.

SCE explained that standardization across utilities is simply not practical because all of the IOU RAMP reports and GRCs will be unique to their respective businesses. All of the IOUs provide testimony, workpapers and/or roadmaps that give detailed information on how the RAMP was integrated into the respective GRC showings. For example, SCE provided detailed and specific testimony and workpapers in its TY 2021 GRC that addressed how RAMP and the GRC are integrated; whereas, PG&E provided a map from the RAMP to the GRC that translates how mitigation and control programs are incorporated into the GRC. Meanwhile, SoCalGas and SDG&E served testimony that provided a roadmap of RAMP-related costs, a dedicated chapter on RAMP-to-GRC integration, and additional testimony and workpapers to delineate RAMP cost estimates.

At the end of its presentation, SCE stated that the IOUs will continue to provide information on how mitigations and controls are incorporated into the GRC. The IOUs remain open to parties' feedback on this topic.

6.3 Discussion

Following SCE's presentation, parties provided comments. SPD stated that it sounds like the IOUs are different and that the outcome of this proceeding will be three separate templates for integrating GRC and RAMP for PG&E, SCE, SoCalGas and SDG&E. In response, SCE stated that making specific things consistent would be better than just having a template from one GRC to the next. SPD stated that a working group could work on standardization among the IOUs, as RAMP continues to evolve. TURN stated that it wants a clear connection between RAMP and GRC (*e.g*., whether the IOU changed anything in the GRC because of feedback received in RAMP), and the IOUs should make those connections clear as to what has been identified as a major risk and how the IOUs are funding those risks in the GRC. SCE replied that it agrees with TURN that the product should be transparent. Cal Advocates agreed with TURN that a template with a minimum set of components would be good. Lastly, Cal Advocates stated that it would like to see a chain between the S-MAP and RAMP and the work completed in the GRC, to see actual improvements in safety which may not be a single template, but there should be a clear set of connections and alignment within the same utility. In its March 4 Post-Workshop Comments, PFC expresses that there is "no meaningful justification for not standardizing RAMPs across the utilities." PCF also indicated its "agree[ment] with the Energy Division that the utilities should present activities in the same manner in both the GRC and the RAMP."

7. Topic 2: Track 3.a.ii – Merger of the RSAR and Other Accountability Reports

7.1 Staff Proposal – Merge Existing Reports Into RSAR

ED proposed that further discussions take place regarding merging existing gas safety-related spending accountability reports with the RSAR. ED also proposed methods for imputing authorized costs and work completed. ED stated that costs show up in RSAR as authorized GRC dollars and recorded costs. ED stated that there needs to be a standard method for the IOUs to show how authorized costs are imputed in the RSAR because the public has a hard time understanding how this is done. Additionally, ED recommended that IOUs explicitly reference workpaper description activities in their variance explanations. Lastly, ED would like the IOUs to explicitly identify activities with no recorded costs as cancelled or deferred.

7.2 IOU Presentation – Consolidation of Existing Gas Reports into the RSAR and Methods to Achieve More Safety Spending Visibility

On behalf of the IOUs, PG&E presented that the IOUs are supportive of merging the existing accountability reports. Specifically, the IOUs propose to consolidate relevant information from the following existing gas safety reports (referred to herein as "Gas Reports") into their RAMP and RSAR, where applicable, with the retirement of those separate Gas Reports:

- PG&E's Gas Transmission and Storage (GT&S) Compliance Report pursuant to D.19-09-025;
- PG&E's Gas Distribution Pipeline Safety Report (GDPSR) pursuant to D.11-05-018;
- SDG&E's Gas Transmission and Distribution Safety Report pursuant to D.13-05-010; and
- SoCalGas's Gas Transmission, Distribution, and Storage Safety Report pursuant to D.13-05-010.

PG&E stated that the applicable Public Utilities Code (PUC) Sections 958.5 and 591's requirements can be satisfied through the RSAR and RAMP Reports. Information would be included in the RSAR using RSAR standards/thresholds for reporting. Gas Report information beyond scope of the RSAR would retire with the Gas Reports. SoCalGas and SDG&E added that their RSAR already provides the PUC Section 985.5 required information.

Regarding achieving more visibility into safety spending, PG&E, on behalf of the IOUs, presented that IOUs have or intend to impute most RAMP mitigations and controls and will provide a view of imputed and recorded amounts as part of upcoming RSARs. Also, as part of RSARs, the IOUs will identify adopted activities that are cancelled or deferred. To aid with future RSARs, the IOUs will also include work units where applicable in GRC filings and are not opposed to providing workpaper references as part of variance explanations, where applicable, in RSARs.

7.3 Discussion

Comments on Topic 2 (Track 3.a.ii) were held until discussion of Topic 4.

8. Topic 3: Track 3.a.iii. Redundancies Between RAMP, GRC, and RSAR

8.1 Staff Proposal – Address Reporting Redundancies

ED noted that there were no topics for discussion on this item.

9. Topic 4: Track 3.a.iv. GRCs Resolved by Settlement Agreement

9.1 Staff Proposal – Workshop Discussion to Resolve Support Issues

ED encouraged workshop discussions to include how GRC proceedings resolved via Settlement Agreement will provide needed support to related RAMPs and authorized values for RSARs.

9.2 IOU Presentation – Processes Exist to Review IOUs' RAMPS and GRCs

On behalf of the IOUs, SoCalGas/SDG&E responded to ED staff's proposal for a workshop discussion on how GRC settlements could include support related to RAMP reporting and authorized values for RSARs. SoCalGas/SDG&E stated that, although guidelines may be helpful, because parties spend significant efforts to reach settlement agreements, any guidelines developed should not negatively impact parties' ability to conduct and ultimately reach settlement agreements in GRCs. The Commission's Rules of Practice and Procedure currently define requirements related to settlements. That said, the IOUs are not opposed to establishing guidelines with respect to RAMP and RSARs for parties to consider during the settlement process. SoCalGas/SDG&E stated that if guidelines are established for settlements, GRC decisions should mirror the same level of detail. Currently, in situations in which a GRC decision (settled or litigated) does not provide the level of detail required to explicitly identify authorized amounts, IOUs impute authorized values and explain how this was accomplished in RSARs. SoCalGas/SDG&E noted that imputing authorized values may still be required and RSARs will address how imputing was accomplished in accordance with applicable approved settlements. SoCalGas/SDG&E made clear that there is value in settlements and the IOUs do not want new requirements that would hinder the ability to settle. Guidelines, provided by the Commission, should leverage existing processes.

9.3 Discussion

The discussion that followed pertained to Topic 2 (Track 3.a.ii); there was no discussion regarding Topic 4 (Track 3.a.iv).

Following SoCalGas/SDG&E's presentation, TURN underscored that it is important for RSARs to include units in order to see that progress is made toward identifiable targets. Cal Advocates asked whether the Gas Reports would be simply incorporated into RSAR, to which PG&E replied yes. However, additional gas program information beyond the RSAR standards would no longer be provided. PG&E explained that the Gas Reports are partially duplicative of what the Commission's Staff already receive in the RSAR. Other than PG&E's Gas Transmission and Storage Compliance Report, the Gas Reports are submitted directly to Commission Staff and not filed. PG&E indicated it is their experience that while Staff currently makes inquiries, there is no requirement that ED or SED issue an evaluation report. Cal Advocates also commented that the Gas Reports are provided on a more frequent basis than RSARs and RAMPs. In response to Cal Advocates' comment, SoCalGas and SDG&E clarified that their Gas Reports are submitted twice a year; however, the first submission includes only numbers for the first half of the year and the second submission includes numbers for the full year and variance explanations.

SPD commented that there needs to be a discussion as to who will review the Gas Reports' information if being incorporated into RSAR because Gas Reports are currently submitted to ED and SED while review of the RSAR is the responsibility of ED. SPD pointed out that objectives of the original reports should be met and nuances between the reports, including who receives each report, need to be addressed. SoCalGas/SDG&E added that additional reports have been initiated since the enactment of the Public Utilities Code 958.8 that created the Gas Reports which are reviewed by SPD, including the Safety Performance Metrics Report and eventually the Risk Mitigation Accountability Report (RMAR). In response, ED stated that efficiencies of consolidating reports are obvious, but the granularity and frequency do not match.[5] Therefore, further discussions are warranted, and this is just the beginning of the conversation.

In its March 4 Post-Workshop Comments on Staff Proposal Topic 2 (Track 3.a.ii), "PCF disagrees with the Energy Division's statement 'that there needs to be a standard method for the IOUs to show how authorized costs are imputed in the RSAR because the public has a hard time understanding how this is done.'" PCF expressed its view that "[o]nly actually authorized amounts should be used," rather than use of 'imputed' authorized amounts.

[5] In its March 4 Post-Workshop Comments, "PCF agrees with the Energy Division but posits that, more important than granularity or frequency, the legislative intent and purpose of each report should be the guiding factor in discussions on merging reports."

10. Topic 5: Refining RAMP and GRC Procedural Requirements

10.1 Cal Advocates Presentation and Discussion

Cal Advocates focused its presentation on Track 3, "Refining RAMP and Related Procedural Requirements" Topics 3.b. and 3.c. (November 2, 2020 Scoping Memo Ruling at page 6):

> b. "Should Rate Case Plan requirements be updated to reflect any clarifications adopted in this proceeding?"
>
> c. "Other potential RAMP clarifications or refinements as needed, including those identified in D.20-01-002."

Cal Advocates recommends that the Commission include these clarifications and refinements to improve the RAMP and related procedural requirements:

1. Risk and accountability reporting should be revised to provide meaningful context including graphical indications of historical progress, current status, as well as depicting how near term planned mitigations fit into the context of a long-term mitigation plan. This information should be reported annually and included in both the RAMP and GRC filings.

   For example, 150 miles of conductor hardening authorized; 100 miles actually hardened out of 5,000 miles that need to be hardened in High Fire Threat Districts.

2. RAMPs and GRCs should include utility assessment of prior and proposed Mitigation Program Effectiveness. Utilities should develop and use appropriate program specific criteria for assessing mitigation program effectiveness. Utilities should also include a comparison of expected and actual effectiveness.

   Discussion:

   SPD questioned what kind of methodology was envisioned for measuring mitigation effectiveness. Cal Advocates responded that it would be dependent upon the mitigation program and that it would be difficult to have a common methodology for all programs. The expectation is that when an IOU proposes a mitigation program in its GRC, it should anticipate a specific outcome from that program and use that in making its decision. To demonstrate this, the utility should provide granular program level data and criteria as to why the program was selected, what the program is anticipated to do, and parties could review it. SPD further asked if Cal Advocates anticipates that the risk score would use the Multi-Attribute Value Function (MAVF) to perform the risk score calculation. Cal Advocates suggests that the use of the MAVF would be a good topic for future discussion. Mitigation programs proposed in GRC filings include much more granular information than the level of programs presented in RAMP applications. SPD asked if Cal Advocates envisions a uniform approach for measuring effectiveness across utilities. Cal Advocates stated that it would be difficult to develop a uniform approach across utilities. Rather, Cal Advocates suggested that each IOU develop its own metric to match and describe its unique processes and share its approach to assessing effectiveness across the utilities to assist in the development of best practices.

3. RAMPs and GRCs should include a comparison of expected and actual mitigation program RSE values.

4. The Commission should standardize GRC mitigation programs reporting. For example, pole replacement programs should be reported with the number of poles to be replaced, as opposed to reporting only a budget for pole replacements.

5. The Commission should require utilities to list the comments by parties in the RAMP and when/how the utility has addressed the comments in its GRC. Furthermore, parties input from the pre-RAMP workshop should be included in RAMP filings.

   Discussion:

   At the workshop, there was discussion that page 42 of D.14-12-025 specifies that a "Utility [must] incorporate RAMP results into its GRC filing." To avoid past differences in how utilities incorporate RAMP results into GRCs, Cal Advocates recommends that the Commission provide explicit direction to provide transparency, accountability and ensure that utilities are addressing party concerns in the GRC.

While not presented at the workshop, in its March 4 Post-Workshop Comments Cal Advocates recommends that an additional RAMP refinement be included in Section 9 of the report discussing Topic 5 Refining RAMP and GRC Procedural Requirements:

6. Utility RAMP applications should include and consider the results of utility Climate Change Vulnerability Assessments, the requirements for which are laid out in D.20-08-046.[6] These assessments are required to include the best available forward-looking climate data available for the purposes of maintaining resilient and reliable service.[7] D.20-08-046 also puts forth that "Climate change adaptation planning in a time of worsening climate impacts is a prudent step to ensure the safety and reliability of the investments and operations of all California investor-owned utilities."[8] Given the acknowledged urgency of utility planning for climate change impacts, and the fact that these impacts are already

---

6 D.20-08-046, Decision on Energy Utility Climate Change Vulnerability Assessments And Climate Adaptation in Disadvantaged Communities (Phase 1, Topics 4 and 5) (August 27, 2020).

7 D.20-08-046, p. 2 ("At its essence, climate change adaptation for California's investor-owned energy utilities focuses on incorporating the best available climate science into utility infrastructure and operational planning for the long term to help ensure provision of resilient and reliable service to all customers.").

8 D.20-08-046, p. 5.

occurring,[9] the RAMP process is an ideal venue for considering climate change impacts as they pertain to current top utility safety risks (*e.g*. wildfire). Therefore, Cal Advocates recommends that RAMPs be required to incorporate the results of climate change vulnerability assessments when assessing top utility safety risks, starting with the first scheduled vulnerability assessment filing by Southern California Edison Company (SCE) in 2022, which will be filed the same day as SCE's RAMP application.[10] Cal Advocates recommends that discussion of specific rules for incorporation of vulnerability assessment results into RAMP filings take place within an RDF Track 3 Working Group.[11]

11. Topic 6: Track 3b. Updates to RCP Requirements

11.1 Staff Proposal - Process for Revising RAMP, and Method Linking the RAMP and GRC

ED proposed to create a process for revising or supplementing the RAMP (particularly requirements for MAVF). ED also proposed that a methodology should be identified to link the RAMP's findings (particularly mitigation costs) to the GRC.

11.2 IOU Presentation – Processes that Currently Exist and Integration of RAMP Into the GRC

SoCalGas/SDG&E, on behalf of the IOUs, commented that RAMP is a report that provides a process for utilities to present its risk mitigation information to interested parties and the Commission, and feedback is received during the RAMP process. The utilities take feedback received on their respective RAMP filings seriously. SoCalGas/SDG&E responded to Staff's proposal stating that the process currently in place requires the utilities to integrate RAMP results, including comments to the RAMP filings, into GRCs and that no additional processes are needed or required. SoCalGas/SDG&E further clarified that the RCP requirements for reporting are evolving and the utilities continue to pivot and include requirements as they evolve. Given the revised schedule for filing GRCs, there is sometimes not enough time to revise testimony or execute new or additional analysis and meet the filing deadline. SoCalGas/SDG&E further stated that some of the comments received in RAMPs (particularly where comments conflict with each other) would be better addressed in a statewide proceeding, such as the S-MAP forum, rather than in a utility-specific GRC.

---

9 Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja. (California Governor's Office of Planning and Research, Scripps Institution of Oceanography, California Energy Commission, California Public Utilities Commission). 2018. Statewide Summary Report. California's Fourth Climate Change Assessment. Publication number: SUMCCCA4-2018-013. https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.

10 D.20-08-046, p. 100.

11 Due to the submission of this recommendation in March 4 Post-Workshop comments to the draft Workshop Report, parties have not yet had an opportunity to comment on this recommendation.

SCE also responded to Staff's proposal stating that RAMP does not provide GRC-quality forecasts, instead the RAMP provides cost estimates for mitigation activities. The RAMP informs, but is not intended to serve as a substitute for the cost forecasts presented as part of a reasonableness showing in the GRC that occurs a year later. Additionally, in their respective GRCs, the IOUs explain the differences and the variances that occur between the RAMP and the GRC, and provide a roadmap to show how the RAMP integrates into the GRC. The IOUs will continue to follow this format. SCE further stated that each IOU's GRC is the appropriate venue to address specific concerns about the variances; however, generalized requirements should be addressed in a statewide proceeding.

11.3 Discussion

TURN responded to the IOU's presentation stating that all of the information in the RAMP, including the RSE, is a tool for justifying proposals in the GRC. To the extent IOUs are receiving feedback in the RAMP, it gives the utility an opportunity to improve their GRC and it is TURN's expectation that their comments be addressed. TURN further stated that the IOUs should highlight and acknowledge the feedback received and whether or not it was incorporated into the filing or if any calculations were changed. TURN disagreed that some issues be dependent to the timing of S-MAP (previously triennially) because that would cause an undue delay in addressing those issues.[12] SoCalGas/SDG&E responded by stressing the importance of timely feedback due to multiple workshops and the narrow windows in the RAMP process. SCE also responded agreeing that comments from intervenors that would make the showing more accurate or transparent should be included; however, if a party is seeking to change the requirements then, as a matter of due process, all parties need to be heard before the change is enacted.[13]

ALJ Fogel requested background regarding why the RAMP estimates are different from the GRC forecasts and requested guidance regarding how to follow the costs between the two filings. SoCalGas/SDG&E responded that there are several differences between the two reports making tracking costs difficult, namely: (1) costs in GRCs are presented by organization whereas the RAMP is presented by activity; (2) the RAMP reflects safety risk cost estimates only and those that are anticipated to be proposed in the next GRC; and (3) the GRC forecast is calculated closer to the operating year. SCE also responded that the Commission was very thoughtful in establishing these different phases – the RAMP and the GRC. The GRC forecasts represent a different timeframe than the RAMP estimates, and that the RAMP is not seeking funding. Thus, they are two different types of showings with two different goals. Also, the GRC forecasts are developed significantly closer in time to the date that the utility actually files its application seeking funding approvals.

ALJ Fogel followed up with an additional question asking if the IOUs take the RSEs from the RAMP and update them in the GRC. SoCalGas/SDG&E responded that according to the S-MAP settlement agreement, IOUs are required to update the RSEs from RAMP in their GRC. The

---

12 PCF similarly disagreed, as expressed in its March 4 Post-Workshop Comments.

13 In its March 4 Post-Workshop Comments, PFC indicated its concurrence with SCE's viewpoint.

IOUs provide a roadmap in their GRC of changes or updates made between the RAMP and GRC processes.

ALJ Fogel asked for a description of the differences between the assumptions used to develop the RAMP versus the GRC forecast. SCE responded that they used the factors known at the time to develop the RAMP; and the RAMP may omit information that would support a full reasonableness showing because the RAMP itself is not a funding request. SoCalGas/SDG&E added that this might be a utility specific answer; however, at SoCalGas/SDG&E, the RAMP is activity-based whereas the GRC is workpaper based largely organizationally and the GRC workpapers are comprised of multiple components that include risk activities as well as other activities' costs.

ALJ Fogel noted that she remains concerned about being as efficient as possible with these processes and asked that stakeholders be mindful of avoiding duplication of effort in the production and the review of the RAMP and GRC.[14] TURN concurred stating that inclusion of the intervenor's RAMP comments into the GRC will aid in making the review process more efficient. PG&E responded that because they are incorporating the RAMP feedback and other inputs into the GRC that will lead to a degree of change. The GRC has a more refined forecast versus the RAMP estimate, but the RAMP is the lead process into the GRC. The RAMP focuses on the risk modeling and getting that right.

ED stated that there is a need to develop a process to close RAMP applications and the S-MAP is the venue for the parties to do so. ED suggested that working groups discuss how to accomplish closing RAMP proceedings in an efficient and effective timeframe prior to filing of the GRC Application.

In response to the ED's proposal that a methodology should be identified to link the RAMP's findings (particularly mitigation costs) to the GRC," PCF, in its March 4 Post-Workshop Comments, states "that no reason exists to reinvent the wheel. The RAMP filing and comment process already forms the basis for a utility's 'assessment of its safety risks in its general rate case filing.'" PCF recommends that the "Commission focus on enforcing existing requirements." On the topic of differences between RAMP estimates and GRC forecasts, PFC also indicated its view that in GRCs costs should be presented by program rather than by organization and "that the programs should be traceable from the RAMP to the GRC to the RSAR." However, with respect to ED's comment that "there is a need to develop a process to close RAMP applications and the S-MAP is the venue for the parties to do so," PFC in its March 4 Post-Workshop Comments disagrees "and submits that this statement by the Energy Division contradicts past Commission decisions."[15]

14 In its March 4 Post-Workshop Comments, PFC indicated that it "shares ALJ Fogel's concerns about efficiency and the need to avoid duplication of effort from the RAMP to the GRC."

15 Citing as an example I.19-11-010, Order Instituting Investigation into the Risk Assessment and Mitigation Phase Submission of Southern California Gas Company (November 7, 2019), p. 5 describing circumstances for an OII to be consolidated with a GRC or closed.

12. Topic 7: Track 3.c. RAMP Clarifications and Refinements

12.1 Staff Proposal – Mitigation Risk Scores in Attrition Years and Master Data Requests

ED stated that the Rate Case Plan Decision (D.20-01-002) directed the IOUs to consider a Master Data Request (MDR) guideline for proceedings such as RAMP and RSAR. ED pointed out that the issue of a master data request in the context of the GRC was addressed in Workshop #2 and the consensus was that the workshop process has been the venue for seeking clarifications and is working formally (hearings) and informally (workshops).

ED stated that there is a need to include risk scores in RAMPs for attrition years. This issue pertains to development of a future RMAR. ED questions whether risk scores would be comparable between RAMPs and would it be possible or even desirable.

12.2 a IOU Presentation – Post-Test Year Cost Estimates

There are multiple methods for determining post-test year revenue requirements and each utility must support their attrition proposal with information to meet the burden of proof in their respective GRCs. SoCalGas and SDG&E use an escalation-based mechanism to determine post-test year revenue requirements and largely do not provide project specific forecasts in the GRC beyond the test year. Given that SoCalGas and SDG&E use a mechanism, not project forecasts, in the post-test years and the intent of RAMP to inform GRCs in general, a requirement to provide post-test year cost estimates in RAMP is not applicable for SoCalGas and SDG&E. Project forecasts for post-test years are not needed as current reporting requirements (the Safety Performance Metric Report and the RSAR) demonstrate how mitigations perform in post-test years by comparing authorized funding and work units (where available) to recorded actual information.

SCE stated there is a difference among how the utilities calculate attrition in the post-test years. SCE bases their attrition years on project forecasts as opposed to an escalation factor. SCE will be providing the post-test year cost estimates in the RAMP and GRC wherever feasible for purpose of risk mitigation scoring. Post-test year cost estimates in RAMP seem to be of limited usefulness unless post-test year project specific funding is authorized in GRCs. SCE will provide a reconciliation and variance explanation if costs estimates change in the year between the RAMP filing and the GRC application.

12.2 b IOU Presentation – Master Data Request for RAMP

On behalf of the IOUs, SCE stated that they do not feel having an MDR for RAMP would provide sufficient benefits. As the Commission has stated, the RAMP filings are evolving and are somewhat unique from one another. Each IOU's subsequent RAMP to GRC integration may be different making standardization of an MDR difficult. Any additional MDRs for RAMP may also be duplicative of the MDRs in the GRC. IOU's RAMPs are already a rather detailed process involving an extensive showing with workpapers. It is most efficient and productive for all stakeholders if parties review the showing and workpapers before issuing data requests. Otherwise, the utility may be answering data requests when the responsive material is already embedded in the RAMP showing. The process that seems to be favored by stakeholders and repeatedly adopted by the Commission is multiple workshops after the RAMP Report is filed. The IOUs are open to discussions on how to improve the mapping and reader accessibility for our RAMP filings. If desired, additional walk-throughs can be provided to discuss the RAMP filings.

12.3 Discussion

TURN believes RSEs should be limited to the test year and believes that a test year plus an attrition process is preferred because of resource constraints. Conversely, PCF, in its March 4 Post-Workshop Comments, believes an escalation-based mechanism to determine post-test year requirements are not appropriate and recommends that any discussion of post-test year cost estimates recognize: (1) the regulatory compact and attrition year calculations work in two directions, and (2) utilities cannot rely upon attrition year adjustments in certain circumstances.

ED posed the questions: (1) how easy would it be to compare mitigations between RAMPs? and (2) what about attrition years that haven't happened yet in the course of a RAMP that is open? SPD stated that they need to develop a template first for the RMAR and that this discussion is premature. This topic will likely require a workshop to hash out the details. RMAR is considering comparing RSEs from one GRC cycle to another, but what is required to be compared for RMAR purposes remains an open item.

To address ED's and SPD's prompt, SoCalGas/SDG&E stated that the timelines and details for filing RMARs have not been established. Notwithstanding the implementation issues related to RMARs, SoCalGas/SDG&E commented that it was their understanding that the RMAR would not compare RSEs between GRC cycles, but rather would compare authorized to actual RSEs, similar to the RSARs for costs. TURN asked how the concept of authorized RSEs would work. SoCalGas/SDG&E responded that it is unclear how "authorized" RSEs will evolve in GRCs and whether the Commission will provide authorized RSE figures in future GRC decisions. SoCalGas and SDG&E noted that they did not present RSEs in the last GRC and will be doing so in the upcoming GRC. To do what SoCalGas and SDG&E are suggesting, ED stated that RSEs would be needed for the test year and post-test years, and asked how this would work? SoCalGas/SDG&E agreed, explaining that RSEs could be calculated for test years and imputed for post-test years using a similar methodology as the RSARs. SPD responded that the cost component would be rather straight forward as escalation-based values can be used. However, the RSE's numerator is more complicated. From GRC cycle to GRC cycle, there are different requirements and ways for calculating MAVFs, which may require going back to previous RAMPs or GRCs. SPD pointed out that it is premature to have this discussion and this topic should be addressed through a technical working group.

ALJ Fogel noted that D.19-04-020 suspended the requirement for utilities to submit RMARs and the requirement is dependent on Phase 2 of the S-MAP Rulemaking.

SoCalGas/SDG&E voiced concerns about comparing one GRC cycle's authorized to that of a new cycle. It is well recognized that things come up during GRC cycles that may require a utility to re-prioritize funding to address immediate needs. Therefore, for the RMAR, authorized benefits from the current GRC cycle should be compared to actual benefits. ED concluded by recognizing the interest in the discussion and stating it will continue at a later time.

13. Next Steps

Comments should be sent to the SoCalGas and SDG&E representative, to ED and SPD with a copy to the service list. The schedule for comments and the workshop report is:

- Draft Report: February 25, 2021
- Informal Comments: March 4, 2021
- Final Report: March 11, 2021
- Final Report Comments: March 25, 2021

The Final Report is to be issued within 30 days of the workshop conclusion and is to be sent to the Director of Energy Division and Safety Policy Division as well as to the proceeding service list.

After service of the Final Report, ED indicated that working groups will convene. The working groups will discuss each part of the workshop report and will make recommendations. There may also be Staff proposals and/or party proposals in the record; the working groups will determine if these are needed.

14. Appendix A: Workshop Presentation

Consolidated Workshop RCP-RDF

D.20-01-002 Rate Case Plan (RCP) Workshop 4
R.20-07-013 Risk-based Decision-making framework (RDF) Track 3 (aka S-MAP 2.0)

February 9, 2021

11:00 AM to 4:00 PM

California Public Utilities Commission

Outline

- Agenda
- Purpose
- Lessons Learned
- Topic Overview

Agenda 11:00 AM to 4:00 PM

11:00	-	11:15	Introduction and Purpose	
11:15	-	11:30	Lessons Learned and Topic Overview	
11:30	**-**	**12:15**	**Track 3.a.**	**K. Vyas (SCE)**
12:15	-	1:00	Lunch	
1:00	**-**	**2:00**	**Track 3.a.**	**J. York (SDGE); K. Chang & K. Arnold (PGE)**
2:00	-	2:15	Break	
2:15	**-**	**2:30**	**Track 3.b./c.**	**Chris Parkes (Cal Advocates)**
2:30	**-**	**3:00**	**Track 3.b.**	**K. Vyas & J. York**
3:00	**-**	**3:30**	**Track 3.c.**	**K. Vyas & J. York**
3:30	-	4:00	Discussion / Q&A	

Purpose

- Improve integration of Risk Assessment Mitigation Phase (RAMP) into the General Rate Case (GRC) and GRC-related reporting into the Risk Spending Accountability Report (RSAR)
- Standardize the organization and format of GRC and RAMP fillings

This workshop is mandated by both the D.20-01-002 of closed proceeding R.13-11-006 and OIR R.20-07-013 (Track 3)

Lessons Learned
from Energy Division

- The public often doesn't have a good understanding of the risk evaluation process.
- The RAMP often doesn't provide the same level of detail as in the GRC.
- Standardizing units of work for the RSARs is hampered by GRC organization.
- Standardizing the discovery process is hampered by individual IOU organization (see 3.b).
- Programs/mitigations need better definitions.
- The CPUC must decide how it intends to use risk-spend efficiency (RSE) data in its consideration of funding risk reduction activities (see 3.a.ii).
- While the initial RAMP filing includes public participation and CPUC oversight the risk modeling results are often updated before they are presented in the GRC (see 3.b).

Lessons Learned

from Safety Policy Division's

Risk Assessment & Safety Advisory Section

- 2019 SCE GRC Application was an iterative step in the RAMP process:
  1. More thoroughly addressed their RAMP report and CPUC staff evaluation, and stakeholder feedback.
  2. Included a more useful "RAMP roadmap" tying their GRC sections to their RAMP report, that provides a template for future GRC applications.
  3. Utilized improved modeling capabilities to provide a wildfire risk curve that assessed wildfire risk on their distribution system for every circuit mile of the 10,000 miles of distribution system in high fire threat districts.
  4. Enabled greater transparency and stakeholder input into GRC the proceeding, allowing for better GRC decision-making.

Topic Overview
6 Topics of Track 3

From OIR R.20-07-013

Track 3: Safety Performance Metrics

6 Topics in Track 3

1. Track 3.a. Cost tracking, risk reductions, terms, and processes across RAMPs, GRCs, and RSARs
    - **3.a.i** - Risk mitigation and cost presentation standard: comparing RAMP and non-RAMP activities
    - **3.a.ii** - Merge the RSAR and other accountability reports
    - **3.a.iii** - Address potential redundancies between RAMP, GRC, and RSAR filings
    - **3.a.iv** - GRCs resolved via a settlement agreement must provide strong relationships to related RAMPs and authorized values for RSARs
2. Track 3.b. RCP requirements should be updated
3. Track 3.c. RAMP clarifications and refinements

3.a.i – Risk Mitigation and Cost Presentation Standard

Staff Proposal:

1. IOU to present unified methods for identifying RAMP mitigation in the GRC
2. IOU to commit to presenting activities in the same manner in both the GRC and RAMP
3. Develop guidelines to:
   a. Identify common elements between RAMP and GRC
   b. Match RAMP information to the subsequent GRC

Track 3.a

Kris Vyas

Southern California Edison

Standardization of RAMP Faces Similar Challenges as GRC Standardization

- At the Rate Case Plan (RCP) Workshop #2, parties extensively discussed how GRCs are organized to mirror the organization of each IOU's business structure, and IOUs have not received feedback that differences in organization amongst IOU's present any barrier to assessing utility showing or finding items within the showing. Stakeholders did not raise any concerns
- Similarly, it is difficult to standardize RAMPs across IOU's. The IOU's have different organizations, business lines, enterprise risks, proposed controls, mitigations, and funding approvals
- Further, the mechanism to compare the RAMP to the GRC is tied to unique accounting systems for each of the IOUs
- The IOUs agree that presentation in RAMP should be generally consistent with the IOU's GRC to the extent reasonably possible. But funding is not sought in RAMP, and reasonableness is not determined. The granularity, level of detail/workpapers, and justification presented in RAMP does not appear to be fully applicable to the GRC

The IOUs Currently Provide Testimony, Workpapers and Roadmaps Detailing RAMP To GRC Integration

- As previously mentioned, all of the IOU RAMP reports and GRCs will be unique to their respective businesses, and therefore any standardization across utilities is simply not practical
- All of the IOUs provide testimony, workpapers and/or roadmaps that give detailed information on how the RAMP was integrated into our respective GRC showings
  - SCE provided detailed and specific testimony and workpapers in our TY 2021 GRC that addressed how we integrated RAMP and GRC
  - PG&E provided a map from the RAMP to the GRC that translates how mitigation and control programs are incorporated into the GRC.
  - SoCalGas and SDG&E served testimony that provided a roadmap of RAMP-related costs, a dedicated chapter on RAMP-to-GRC integration, and additional testimony and workpapers to delineate RAMP cost estimates.
- The IOUS will continue to provide information on how mitigations and controls are incorporated into the GRC. We welcome parties’ feedback

Intervenor Comments

Lunch

3.a.ii – Merge the RSAR and Other Accountability Reports

Staff Proposal:

1. Consider merging existing spending accountability report with the RSAR D.19-04-020.
2. Propose methods for inputting authorized costs and work completed.
3. IOU to reference workpaper description activities in variance explanations.
4. IOU to identify activities with no funding as cancelled or deferred.

Track 3.a.ii

Jamie York
SoCalGas / SDG&E

Kimberly Chang Pacific
Gas & Electric

Ken Arnold
Pacific Gas & Electric

Gas Reports in Addition to RSAR (3.a.ii)

In addition to the Risk Spending Accountability Report, the IOUs submit Gas Reports specific to gas operations activities.

Report	IOU	Description	Directive
Gas Transmission and Storage (GT&S) Compliance Report	PG&E	Provides a description of the Integrated Planning Process, Budget and Spend, and safety programs details for Pacific Gas and Electric Company's Gas Transmission and Storage system.	D.19-09-025 *(PG&E's 2019 GT&S Rate Case)*
Gas Distribution Pipeline Safety Report	PG&E	Provides a description of the Integrated Planning Process, Budget and Spend, and Capital Project details for Pacific Gas and Electric Company's Gas Distribution system.	D.11-05-018 *(PG&E's 2011 GRC)* Continued in D.17-05-013 *(PG&E's 2017 GRC)*
Gas Transmission and Distribution Safety Report	SDG&E	Provides a description of the Strategic Planning and Decision-Making Process, Budget and Spend, and variance explanations for SDG&E's Gas Transmission and Distribution Systems.	D.13-05-010 *(Sempra Utilities' 2012 GRC), Attachment C.*
Gas Transmission, Distribution, and Storage Safety Report	SoCalGas	Provides a description of the Strategic Planning and Decision-Making Process, Budget and Spend, and variance explanations for SoCalGas's Gas Transmission, Distribution, and Storage Systems.	D.13-05-010 *(Sempra Utilities' 2012 GRC), Attachment C.*

Proposal to Merge Existing Spending Accountability Reports

To merge existing Gas Reports with the RSAR, the IOUs propose the following be adopted:

- Consolidation of relevant information from existing Gas Reports into the RSAR and retirement of separate Gas Reports.
    - Information will be included in the RSAR using RSAR standards/thresholds for reporting.
- PU Code requirements that initiated the Gas Reports can be satisfied through the RSAR and RAMP Reports.

Public Utilities Code 958.5 and 591

PU Code 958.5

- (a) Twice a year, or as determined by the commission, each gas corporation shall file with the division of the commission responsible for utility safety a gas transmission and storage safety report. The division of the commission responsible for utility safety shall review the reports to monitor each gas corporation's storage and pipeline-related activities to assess whether the projects that have been identified as high risk are being carried out, and to track whether the gas corporation is spending its allocated funds on these storage and pipeline-related safety, reliability, and integrity activities for which they have received approval from the commission.
- (b) The gas transmission and storage safety report shall include a thorough description and explanation of the strategic planning and decision-making approach used to determine and rank the gas storage projects, intrastate transmission line safety, integrity, and reliability, operation and maintenance activities, and inspections of its intrastate transmission lines. If there has been no change in the gas corporation's approach for determining and ranking which projects and activities are prioritized since the previous gas transmission and storage safety report, the subsequent report may reference the immediately preceding report.
- (c) If the division of the commission responsible for utility safety determines that there is a deficiency in a gas corporation's prioritization or administration of the storage or pipeline capital projects or operation and maintenance activities, the division shall bring the problems to the commission's immediate attention.

PU Code 591

- (a) The commission shall require an electrical or gas corporation to annually notify the commission, as part of an ongoing proceeding or in a report otherwise required to be submitted to the commission, of each time since that notification was last provided that capital or expense revenue authorized by the commission for maintenance, safety, or reliability was redirected by the electrical or gas corporation to other purposes.
- (b) The commission shall ensure that the notification provided by each electrical or gas corporation is also made available in a timely fashion to the Office of the Safety Advocate, Public Advocate's Office of the Public Utilities Commission, and parties on the service list of any relevant proceeding.

Visibility on Safety Spending (3.a.ii)

Consider how to achieve more visibility into safety spending by:

1. Improve methods "imputing authorized" costs:
   - IOUs have or intend to impute most RAMP mitigations and controls and will provide a view of imputed and recorded amounts as part of the upcoming Risk Spending Accountability Report.
2. Relate authorized costs for work done:
   - IOUs provide this analysis as part of the RSAR; GRC filings will include work units, where applicable.
3. Reference workpapers in variance explanations:
   - IOUs are not opposed to providing workpaper references as part of variance explanations, where available.
4. Identify authorized activities that are cancelled or deferred:
   - IOUs provide this information as part of the RSAR pursuant to the 2019 SMAP Decision (D.19-04-020), for programs that meet the applied threshold, "…whether any projects or other units of work were canceled, deferred, or expanded that may have led to the difference."

3.a.iii – Address redundancies between RAMP, GRC, and RSAR

Staff Proposal:

1. Identify and significant redundancies between RAMP, GRC, RSAR fillings.

The IOUs do not have any topics for consideration here at this time.

3.a.iv – GRCs resolved via a settlement agreement

Staff Proposal:

1. Workshop discussions should state how GRC proceedings resolved via Settlement Agreement will provide needed support to related RAMPs and authorized values for RSARs.

Prudent Touchpoints With Settlements

- Parties spend significant efforts to reach settlement agreements. Any guidelines developed should not negatively impact parties' ability to conduct and ultimately reach settlement agreements.
- IOUs are not opposed to establishing guidelines with respect to RAMP and RSARs for parties to consider during the settlement process.
- If guidelines are established for settlements, GRC decisions should mirror the same level of detail.
- Imputing authorized values may still be required and RSARs will address how imputing was accomplished in accordance with applicable approved settlements.

Intervenor Comments

Break

Track 3.b and 3.c

Chris Parkes

Public Advocates Office

PUBLIC ADVOCATES OFFICE

D.20-01-002 Rate Case Plan (RCP)
R.20-07-013 Risk-based Decision-making Framework (RDF)

Consolidated Workshop 4: Refining RAMP and GRC procedural requirements

Public Advocates Office

February 9, 2021

Chris Parkes, Supervisor, Financial Impacts Section, Safety Branch

Agenda
Energy Division Track 3 Workshop 6 Topics

3.a. Cost tracking, risk reductions, terms, and processes across RAMPs, GRCs, and RSARs.

i. Risk mitigation and cost presentation standard: comparing RAMP and non-RAMP activities.

ii. Merge the RSAR and other accountability reports.

iii. Address potential redundancies between RAMP, GRC, and RSAR filings.

iv. GRCs resolved via a settlement agreement must provide strong relationships to related RAMPs and authorized values for RSARs.

3.b RCP requirements should be updated.

3.c RAMP clarifications and refinements.

This Presentation

Scoping Memo/Track 3:

“Refining RAMP and Related Procedural Requirements”

3.b. : “Should Rate Case Plan requirements be updated to reflect any clarifications adopted in this proceeding?”

3.c: “Other potential RAMP clarifications or refinements as needed, including those identified in D.20-01-002.”

Cal Advocates proposes refinements to:

1) Increase transparency;

2) Increase accountability; and

3) Increase dissemination and application of best practices.

PUBLIC ADVOCATES OFFICE

Increasing Transparency, Accountability, and Best Practices

1. Utilities should enhance annual safety metrics and risk spending/mitigation accountability reporting:
   - Risk and accountability reports should be revised to provide meaningful context including graphical indications of historical progress, current status, as well as depicting how near-term planned mitigations fit into the context of a long-term mitigation plan.
     - e.g. 150 miles of conductor hardening authorized; 100 miles actually hardened; out of 5,000 miles that need to be hardened in High Fire Threat Districts.
   - This information should be reported annually and included in both the RAMP & GRC filings.

Increasing Transparency, Accountability, and Best Practices

2. Mitigation Program Effectiveness:

   - RAMPs and GRCs should include utility assessment of prior and proposed Mitigation Program Effectiveness. Utilities should develop and use appropriate program specific criteria for assessing mitigation program effectiveness.
   - Utilities should also include a comparison of expected and actual effectiveness.

3. Risk Spend Efficiency (RSE): Similar to Mitigation Program Effectiveness, RAMPs and GRCs should include a comparison of expected and actual mitigation program RSE values.

Refining RAMP and Related Procedural Requirements

5. The Commission should standardize GRC mitigation programs reporting.
   - For example, pole replacement programs should be reported with the number of poles to be replaced, as opposed to reporting only a budget for pole replacements.
6. The Commission should require utilities to list the comments by parties in the RAMP and when/how the utility has addressed the comments in its GRC.
   - Currently there is no tracking of party recommendations from the RAMP to the GRC. This leads to a lack of transparency and accountability that utilities are addressing party concerns in the GRC.

PUBLIC ADVOCATES OFFICE

Questions/Discussion

Chris Parkes
California Public Utilities Commission
Public Advocates Office
Program & Project Supervisor
Safety Branch, Financial Impacts Section
christopher.parkes@cpuc.ca.gov
415-703-1975

3.b– RCP requirements should be updated

Staff Proposal:

1. List process for revising or supplementing the RAMP (particularly requirements for MAVF).
2. Identify methodology for link the RAMP's findings (particularly mitigation costs) to the GRC.

Track 3.b

Jamie York
SoCalGas / SDG&E

Kris Vyas
Southern California Edison

A Process is Already in Place to Review IOUs RAMPs and GRCs

- RAMP provides a process for reporting an IOU's available risk mitigation information and analysis. Disagreements regarding reporting requirements may be addressed in a statewide proceeding, such as the S-MAP.
- The RAMP process requires a utility to incorporate "RAMP results into its GRC filing" (D.14-12-025 at 42). Accordingly, utilities integrate risk mitigation information into the GRC, considering feedback from staff and parties identified in the RAMP proceeding, which will be evaluated as part of determining specific requests in the GRCs.
- No additional processes, workshops or otherwise, are needed.
- Additional processes would further diminish an already narrow window (set forth in D.20-01-002) for receiving RAMP results and then integrating them into the next GRC.

Integrating RAMP Into GRC

- The IOUs note that RAMP does not provide GRC-funding "forecasts," but simply gives cost estimates for the mitigations. IOUs already explain in the post-RAMP GRC application the difference between the RAMP-chosen mitigations and the GRC-proposed work
- As previously indicated, the IOUs provide testimony, workpapers and/or roadmaps that show how the RAMP was integrated into our respective General Rate Cases. We will continue to do so
- The current RAMP process calls for IOUs to integrate the RAMP results into their GRC. Accordingly, a particular IOU’s GRC is the productive venue to consider whether concerns that may have been raised by Staff and parties in the utility’s RAMP proceeding are adequately addressed in the utility’s GRC showing

Intervenor Comments

3.c– RAMP clarifications or Refinement

Staff Proposal:

1. Include mitigation risk scores in RAMPs for attrition years (i.e. post-test years).
2. Develop a Master Data Request (MDR) guideline consistent with RAMP fillings and each IOU.

Track 3.c

Jamie York
SoCalGas / SDG&E

Kris Vyas
Southern California Edison

SoCalGas and SDG&E Use a Post-Test Year Mechanism; Program Cost Estimates in Attrition Years Are Largely Not Provided

- RAMP is intended to inform IOU GRC proposals.
- SoCalGas and SDG&E support the Staff proposal's statement that "Attrition years from prior GRCs are generally unrelated to the RAMP…"
- Generally, SoCalGas and SDG&E do not provide cost estimates in their RAMP or GRC beyond the test year. Rather, SoCalGas and SDG&E use an escalation-based post-test year mechanism for the GRC.
- SoCalGas and SDG&E support their attrition proposals with information to meet their burden of proof in GRCs.
- Accountability reporting demonstrates how mitigations perform in post-test years by comparing authorized funding and work units (where available) to recorded information.

SCE Plans on Providing Post-Test Year Cost Estimates in its RAMP and GRC

- While SCE is still finalizing our approach for our May 2022 RAMP showing, SCE currently anticipates providing Test Year and Post-Test Year cost estimates in its GRC, and in its RAMP wherever feasible for purposes of risk mitigation scoring
    - Post-Test Year cost estimates in RAMP seem of limited usefulness unless Post-Test Year funding authorization in GRCs also uses cost estimates (rather than simple formula attrition year mechanism)
- SCE will provide a reconciliation and variance explanation if cost estimates have changed in the one year between filing the RAMP and filing the GRC application.

The IOUs Do Not Feel a Master Data Request for RAMP is Warranted

- The IOUs do not feel that having an MDR for RAMP would provide benefits for all parties
- While a respective IOU's GRC remains generally consistent between cases, RAMP filings are likely to evolve and be somewhat unique from each other. In addition, each IOU's subsequent RAMP to GRC integration may be different, again making standardization of an MDR difficult. Any additional MDRs for RAMP may also be duplicative of the MDRs in the GRC
- The utility RAMPs are already a rather detailed process involving an extensive showing with workpapers. It is most efficient and productive for all stakeholders if parties review the showing and workpapers before issuing data requests. Otherwise, the utility may be answering data requests when the responsive material is already embedded in the RAMP showing
- The process that seems to be favored by stakeholders and repeatedly adopted by the Commission is multiple workshops after the RAMP Report is filed
- The IOUs are open to discussions on how to improve the mapping and reader accessibility for our RAMP filings. If desired, additional walk-throughs can be provided to discuss the RAMP filing

Intervenor Comments

Next Steps

- Workshop Report (D.20-01-002 calls for it in 30 days)
  - Compile notes and comments. Circulate draft
  - Final report to be published on CPUC website
- Working Group (Scope p 10)
  - Discussion of the report
  - Identify majority and minority views and recommendations
- Final Proposal
  - Final “outcomes” or “decisions” (e.g. final proposal)

Discussion on Preliminary Comments and Report Schedule

- Draft Report: Feb 25, 2021
- Informal Comments on Draft Report: March 4, 2021
- Final Report: March 11, 2021
- Final Report Comments: March 25, 2021

Questions?

California Public Utilities Commission

Kevin.Flaherty@cpuc.ca.gov
Jordan.Smith@cpuc.ca.gov

Safety Policy Division
Steve.Haine@cpuc.ca.gov
Alex.Pineda@cpuc.ca.gov
Shayla.Funk@cpuc.ca.gov