ORA's Comments to Staff Straw-Proposal
R.13-11-006

The Commission staff will convene a three-day workshop to discuss this proposal. This will be an iterative process where we will refine as we get feedback from all stakeholders. The workshops are scheduled to begin on March 19th at the Commission Auditorium. More details on the workshop to follow.

The large utilities (i.e. SoCalGas, PG&E, SDG&E, and Edison) are asked to submit and serve a case study utilizing the new process – see below. By case study we mean we want the utilities to take this proposal and create an example of how it could work in real life – e.g. a utility can file its own Risk Assessment Planning Proceeding (RAPP) using hypotheticals. We are requesting this approach because the case studies can be used in the workshop to revise/refine the proposal. The utilities are asked to submit and serve their case studies on March 11th.

Logistically, the next steps on this proposal are as follows:

1. SoCalGas, PG&E, SDG&E, & Edison are to submit and serve their case studies on March 11, 2014
2. Workshops (March 19, 20, & 21) with all stakeholders to get feedback
3. Staff will revise the proposal based on the feedback from the workshops
4. Parties will file formal opening and reply comments on the revised proposal.
5. Prehearing Conference (PHC) will be scheduled for April 29, 2014 – ruling to follow.

I. Introduction

Coming out of the energy crisis, the Commission radically changed its policies around energy procurement to ensure reliability as it formed the so called "hybrid market" that combined elements of regulated utility services with competitive markets. This process evolved over the years to become the Long-Term Procurement Plan proceeding (LTPP). The LTPP combined two core functions: approving short-term (generally less than five year) procurement of electric energy supplies on an expedited schedule, and approving long-term contracts for generating resources to ensure adequate generation capacity was available to meet planning reserve margins.

Since the San Bruno natural gas pipeline explosion in 2010, the Commission has faced a similar need for transformation of its policies concerning the safety and resiliency of utility operations. In response to date, the Legislature has enacted multiple statutes, and the Commission has also opened several investigations and rulemakings; however, neither the statutes nor the rulemakings/investigations fundamentally changed the core mechanisms by which regulated utilities consider safety.

In this Rulemaking – R.13-11-006 - the Commission has asked stakeholders how to more effectively integrate safety into utility General Rate Case (GRC) funding proposals, and also asked for ideas to potentially streamline the GRC process. Over eighteen different stakeholders filed comments in response to the Rulemaking. The Staff Straw Proposal draws on the ideas proposed by the Office of

Ratepayer Advocates and the Coalition of California Utility Employees, among other stakeholders.

This Staff Proposal is introducing a process modeled after the LTPP proceeding. The LTPP proceeding focuses on ensuring reliability and ensuring necessary capacity is brought online consistent with state-policy goals. Essentially, the LTPP utilizes a transparent stakeholder process to identify need for resources based on load forecasts, policy directives and future expectations about resource availability and directs each utility to procure a portfolio of contracts to ensuring sufficient generation supply on a territory-wide and local resource area. We are proposing that a similar mechanism be created for complete and transparent stakeholder process to form a risk-mitigation portfolio for each utility – i.e. identifying and ranking the risks to a safer and more resilient system **using a uniform process**, and providing a mechanism for the utilities to propose specific projects to reduce or allay that risk.

The goal of this proposal is to develop fundamental regulatory processes for defining, acquiring, and disseminating risk-based information that supports rate-setting and project prioritizing decisions. This new process - whether in a separate proceeding or a phase of the GRC proceeding - should include the following:

- Description of the utility asset needing replacement or upgrade. The estimated risk, the existing controls already in place to mitigate the risk, and the effect of not replacing or upgrading.
- A description on the method used to estimate the risk. For instance was the risk scored on a purely quantitative basis, a Subject Matter Expert (SME) basis, or a hybrid approach?
- What alternative solutions are available to reduce or eliminate the risk?
- The estimated risk reduction if the replacement or upgrade is authorized or if the other alternatives are authorized.

Developing these processes and the capability to credibly deliver and interpret risk information suggests that several other supporting capabilities may also need to be in place. Utilities may need to expand their risk management processes, and the Commission, as well as interveners may need to expand their own capabilities and understanding of risk management.

II. Process

Here are two possible alternatives for incorporating this process into GRC decision making:

A) A separate proceeding, conducted separately from and in advance of the GRC application, which results in a risk-informed portfolio of projects to address identified risks and uncertainties, and which establishes a ranking of these projects based on their expected costs and anticipated value to ratepayers. For the purposes of this proposal, we coin the term Risk Assessment Planning Proceeding (RAPP). The Commission-approved results of the RAPP process would then be incorporated into the utility GRC application as part of expenditure requests for utility

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operations and capital improvements.

B) Instead of holding a separate proceeding, the risk assessment and project planning could occur as the first Phase of each utility's GRC proceeding, with the risk-reduction project portfolio comprising a separate book of testimony and related working papers, and the budget for the approved project list incorporated into the utility's total revenue request for that Test Year.

While this proposal has selected these two options for consideration, Staff is not opposed to alternatives that fit the concepts further described in this paper. Regardless of the structure for considering risk and mitigation, however, this proposal also sees a necessity for adding a new verification component to GRCs, which would entail the utility at the time it files its Notice of Intent (NOI) to also file a very simple chart showing the projects that were approved versus the projects that were implemented. This verification process is discussed in more detail in the later section of this proposal.

Setting aside for the moment the matter of whether risk analysis is separate and preliminary to the GRC, or an early Phase of the case, this approach essentially consists of three components:

- Step 1 is to identify the risks for a safer and more resilient system, and to create a process that allows the utility to bring to the Commission its justification/rationale for these risks and ways to mitigate them. The outcome of this Step would provide guidance for establishing recommended levels of funding for Safety and Resiliency. We'd like to discuss at the workshop whether this step should be incorporated into the GRC rate case plan.

- Step 2 is the traditional General Rate Case litigation for each utility. The prior identification and/or ranking of the risks to the utility would not guarantee that all costs proposed in the GRC will get approved. In the GRC, stakeholders can debate the cost as well as the path the utility has chosen to eliminate and/or mitigate the risks identified.

- Step 3 is verification. The Commission requires **<u>a uniform and simple verification</u>** system that will be reported by the utility to the Commission's Safety & Enforcement Division (SED). For example, if utility X was approved in 2015 to replace 1000 poles by 2020 with a budget of $200 million; in 2020 the utility should show in a most simple chart that 1000 poles were approved in 2015; in 2016 250 poles were replaced at a cost of $30 million; in 2017 300 poles were replaced at a cost of $65 million; in 2018 450 poles were replaced at a cost of $100 million; the utility will refund the extra $5million and/or will use it for something else that it will clearly identify. This should be illustrated in a table and will include other items that were approved in the GRC.

In the next sections we will further explain each of these three steps.

III. Risk Assessment

The goal of this aspect of the proceeding is for the utility to identify and clearly define its priorities and policies for assuring a safe and resilient system. More specifically, the utility must identify the top risks to its system – the risks must be separated as operational risks that the utility faces, legacy risks, and emerging risks that could impact long-term performance and unanticipated risks to a safer more resilient system[1]. The utility must justify these risks based on measureable and verifiable risk assessment. This process should identify the safety objectives, implementation options, and the information required to evaluate the performance of the proposed projects. Further, the utility must also identify risk mitigation projects. They should show how, and by how much, each project is expected to reduce the probability of a hazardous event occurring and the consequences of the event if it occurs. The utility should also estimate when they expect these safety improvements to be realized and the duration or lifetime of the project impacts (e.g. replaced pipe has expected lifetime of "X" years, employees are retrained every three years, etc.). These projects should be identified as either direct safety mitigation projects (e.g. pipeline replacement), risk assessment projects (e.g. pipeline safety testing and inspection, risk modeling), or safety enabling projects (e.g. safety training).[2] Through this process all stakeholders will have an opportunity to comment on the utilities testimony and provide feedback, if any should be adopted and/or modified. The Commission's final decision would reflect this robust and transparent record.

One of the most apparent challenges is simply identifying the risks to a safer and more resilient system – e.g. breakdowns in infrastructure such as old utility poles in high consequence areas; transformer failures that lead to fires; cybersecurity threats; pipeline failures; natural gas storage failures. The assessment process must be designed to identify and contextualize these risks so that stakeholders can provide, input, feedback and/or meaningful alternatives. The initial workshop for this proceeding is designed to identify/define a risk taxonomy that comprehensively classifies the risks that a utility faces, develop and agree on a set of requirements for measuring risk, evaluate options and alternatives for mitigating risks, and validate a process for prioritizing risks mitigation opportunities.

a) GUIDING PRINCIPLES *for developing risk-based regulations*

Based on a review of several risk management processes, we have identified five guiding principles of risk management that can form the foundation for proactive risk-based regulation.

- Risks involve uncertainty about achieving objectives. Although categories of risk, or even specified risk events can be identified and the likelihood of their occurrence quantified, there is still an underlying element of uncertainty in terms of when, extent of the impact, or ultimate outcomes of some event. Uncertainties are expressed as both negative and positive impacts. Negative impacts hinder the advancement of our objectives and positive impacts promote and enhance our objectives. Regulation should recognize this dual role and capability of risk management and adopt processes that provide incentives to utilities to address and find innovative ways to control risk in ways that comport with and advance stakeholder objectives.

- Risk is an analytically measurable quantity, and may be reduced to a metric that is a function of the probability of an event and the impact of that event. Each event can either enhance or inhibit the ability to achieve objectives. These metrics can characterize risks that have occurred

[1] These are suggested risk categories and may be further developed as part of a risk taxonomy identification process in the RAPP

[2] These are suggested categories that may be further defined as part of the RAPP

in the past (Lagging indicators) or can also assess our expectations of future events (Leading indicators).

- Risk management is predicated on a comprehensive review of risks. The effectiveness of a risk management paradigm depends on the ability to comprehensively review all project risks individually and as a portfolio. Risk occurs at all levels of an enterprise so risk management is the responsibility of everyone.

- Learning is a core competency of effective risk management. The task of resolving uncertainties and reducing negative risk requires that organizations plan for and embrace learning and continuous improvement processes as an integral part of risk management.

- Transparency in risk evaluation processes and third party review is essential to developing robust comparable risk metrics, confidence in the measurement process, and consistency in overall risk management processes.

b) Requirements for Risk Assessment and Planning

In order to better understand how system-wide risk assessment and management can be used to support and achieve the objectives of safe, resilient and cost effective service, we have developed a preliminary set of regulatory process requirements. These requirements incorporate the five guiding principles and also recognize that developing a robust risk management paradigm for regulating IOUs also requires meaningful and informed input from stakeholders. The key issues to resolve with stakeholder input are how to balance the fundamental objectives of safe and resilient service at reasonable rates; how to determine risk tolerance at the program level; and how to determine an acceptable level of risk for a portfolio of programs in the GRC.

The risk assessment process (whether in a separate RAPP proceeding or as a Phase of the GRC) is designed to elicit these three fundamental requirements of risk assessment and management in three steps:

1. Develop an objectives hierarchy / risk taxonomy,
2. Identify and characterize program level risks and mitigating options, and
3. Select an acceptable level of risk given a limited set of alternatives.

These requirements outline the desired outcomes and goals of a new regulatory process.

1. Develop an Objectives Hierarchy / Risk Taxonomy

An objective hierarchy (or risk taxonomy) is a structured way to identify, classify and order the risks that can impact the core objectives of safety, resiliency and costs. While the hierarchy is a stable representation of the concerns of stakeholders, it is also a comprehensive and evolving tool. This tool also documents and includes risks that have not recently occurred or may have not yet occurred.[3] This hierarchy has several benefits:

[3] The staff straw proposal focuses on the overall risk. However, there is an inherent accepted risk in the present systems. With that in mind, focusing on the net change in risk may be more productive as it relates to acceptance of risk relative to the difference from the present state. This may also help deal with the risk of <u>not</u> taking action on a project. While discussions about the risk inherent in the present systems may be productive overall, it may present a level of complexity that does not

- Encourages a comprehensive review of all risks that can impact a utility.
- Refines the understanding of how core objectives are managed and can be impacted by specific programs.
- Creates a clear method for rolling up risks in an agreed on manner.
- Creates a clear way to identify the program risks such as operational, legacy, and emerging risks.

Initially developing and building out this hierarchy can be a challenge. It will require input from IOUs about the systems and process used to manage their systems. Interveners will also have input into how core objectives should be weighted in this hierarchy. Fundamentally the hierarchy is a tool for mapping core objectives to specific programmatic activities.

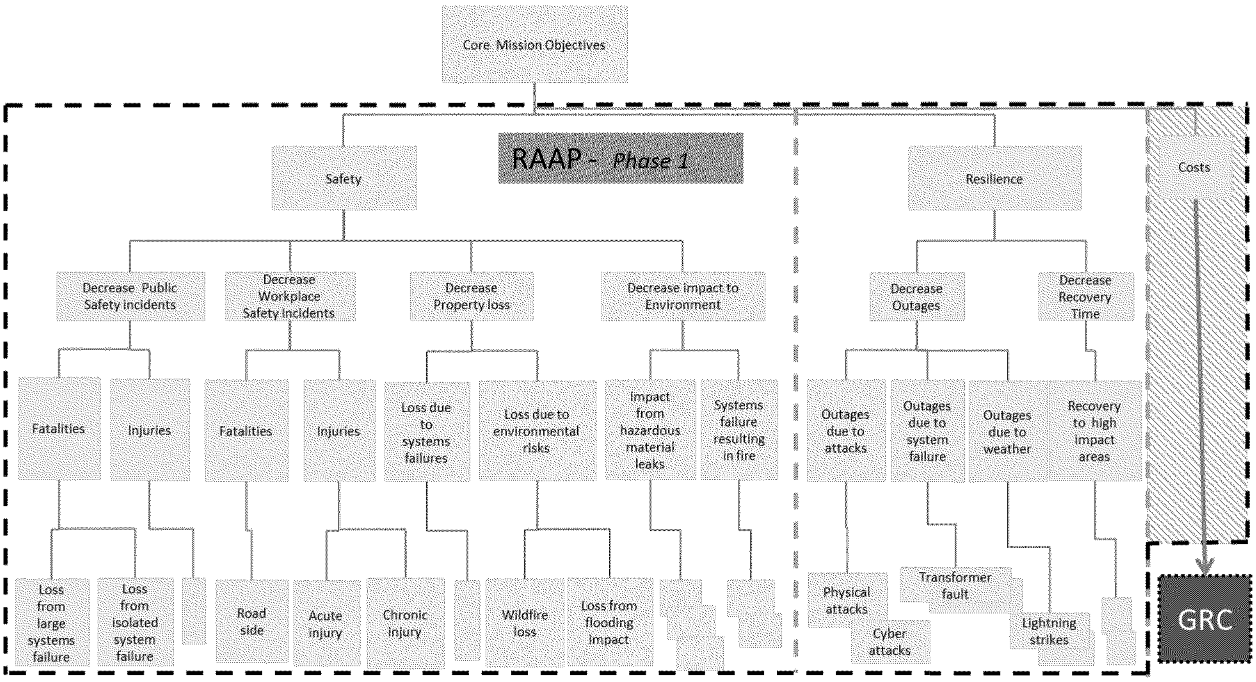

Exhibit 1: Notional diagram of an objective hierarchy –This is not a comprehensive review of objectives

2. Program level risk reporting – Program evaluation

With a hierarchy in place, each and every program proposed within the GRC should be identified within that hierarchy. Each of these proposed programs should be evaluated using a simple estimation of risk. This serves two purposes. First it informs the system-wide evaluation of risks. These program level risks can be rolled up using the hierarchy developed above. Second, it specifies an expectation of the program level risks and serves as a simple performance metric.

Risk evaluation is the IOUs' estimate of the performance expectations, the potential impacts (both negative and positive), and the overall risk mitigation potential for every project within the GRC. While some projects may have a big impact on reliability, and others have an impact on safety, each project nevertheless has some impact on both of these core objectives. This evaluation could be summarized on a one page summary of the projects goals and expectations.

essentially focus on the proposed projects.

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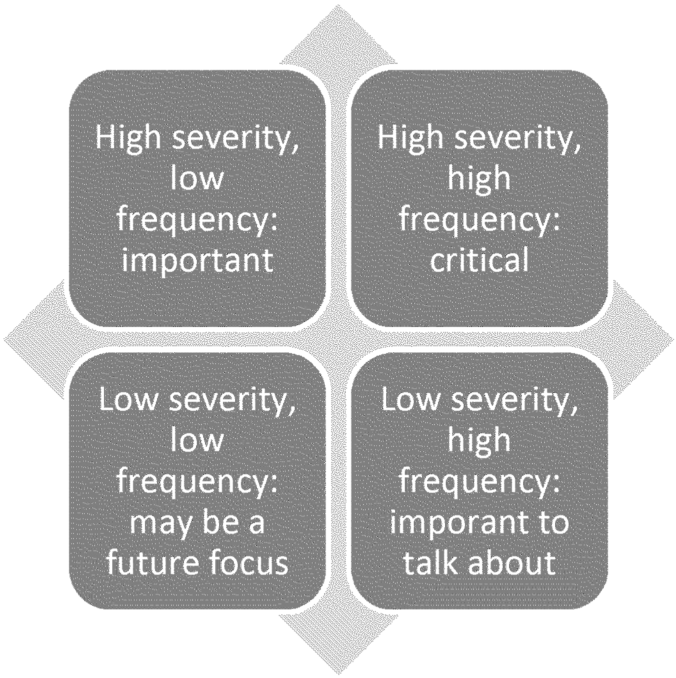
3. *Portfolio segmentation & ranking graphic*

In order to make an evaluation of the full portfolio of requests made by an IOU, we can segment and then potentially rank a program based on the desired criteria. These criteria can be any of the estimated values used in the previous program evaluation phase. Since each program has already been identified and the impacts to safety, resiliency and cost have been agreed on in program summary phase, we can now segment and then within each of those segments rank each of the programs. The segments can be based on a number of criteria and chosen based on whatever the stakeholders believe is most appropriate. This segmenting also identifies the risk classification, so that each type of program is identified and minimum standards and compliance issues can be assured.



Once it is classified whether it is high frequency or low severity, we can then begin to rank each program within that classification/segmentation. Comparing across segmentation the stakeholders would then need to determine the risk cut-off (RAPP line) for all programs – see the figure below. This level of risk acceptance balances all the concerns and implicitly selects projects to be adopted.

With the risk level established the budget constraint would be established within the GRC process.

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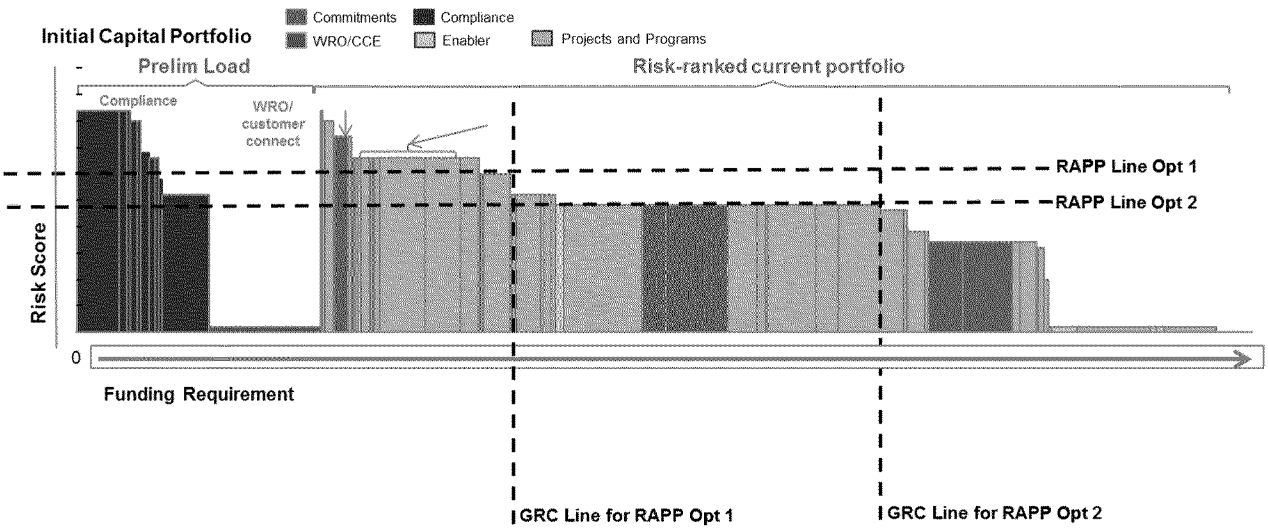

IV. Incorporating the Results of Risk Assessment into the General Rate Case (GRC)

General rate cases are a traditional form of regulatory proceeding, in which, a utility files a revenue requirement request based on its estimated operating costs and revenue needs for a particular test year and the Commission determines a just and reasonable revenue requirement. These cases aim to strike a proper balance between risks the utilities take and reasonable opportunity for returns, taking into account changing economic conditions. The GRC sets the baseline for utility costs to provide reliable, safe, environmentally sound service at just and reasonable rates. Therefore, regardless of where the system safety and security plans will be reviewed and approved, the implementation costs must be reviewed in GRCs.

Essentially, the GRCs are entirely cost driven. The GRC approves the revenues and rates for the test year that was litigated. Year 1 is the test year, and for years 2 & 3 an attrition or rather post-test year ratemaking is also litigated and decided in the GRC. The historical practice has been to litigate the post test-year ratemaking within the GRC.

GRCs are typically filed every three years and are staggered to ensure that the Commission and interveners have dedicated staff. A utility's base year under a three-year cycle is actually the utility's test year from the prior GRC. However, if there is a delay, then that could impact the utility's costs in a way different from what was forecast.

This proposal recommends that a four-year rate case cycle be adopted, thereby giving the utility at least one year of actual spend that will become the base year for the next GRC. It should be understood that the further into the future we forecast the more likely it is that we will be wrong in one direction or another. Therefore, extending our forecast to a four-year GRC cycle will require the Commission to be flexible in dealing with the differences between forecast and actual results. One possibility could be that the utility would be required to file annual advice letters updating top line cost information.

The real question is which GRC cycle will be able to incorporate a new risk-analysis process. To answer this question we will highlight the GRC cycles of the three large utilities and make a recommendation that is reasonable considering timeliness and completeness of the RAPP record.

Current GRC cycles:

- PG&E's GRC = filed in Nov 2012 for test year 2014. The next cycle begins with an application that will be filed in Nov 2015 for test year 2017 (this will commence the 4 year GRC cycle for PG&E of 2017 – 2020.)

- PG&E's Gas Transmission and Storage (GT&S) = filed December 2013 for test year 2015. We will propose that the current GT&S cycle continue as a 4 year cycle.[4] This is consistent with the last PG&E GT&S proceeding in which the Commission adopted a 4 year cycle. Under the 4-year (2015 – 2018) cycle, the next filing will be in December 2017 for test-year 2019.

- Edison GRC = filed in Nov 2013 for test year 2015. The next cycle begins with application that will be filed in Nov 2016 for test year 2018. (This application will commence the 4 year GRC cycle for Edison of 2018 - 2021)

- Sempra GRC = the next filing is an application filed in Nov 2014 for test year 2016. This should be a 4 year cycle (2016 – 2019). This is consistent with the last Commission D.13-05-010 which adopted a 4 year (2012 – 2015) GRC time frame.

If the first option – a separate RAPP proceeding – is determined to be the best choice, there is an additional consideration of providing sufficient time to conduct a proceeding (however expedited) and giving the utility enough time to incorporate results in its subsequent GRC.

To make sure the information used in risk assessment is not out of date by the time the GRC is filed and to make sure the utility has had sufficient time to incorporate the risk assessment developed in a RAPP proceeding into its GRC, we think the RAPP proceeding should be scheduled to conclude 12 months before the GRC is filed. Alternatively, the risk assessment phase of the GRC should conclude 12 months before the next phase of the GRC addressing costs is filed.

With this in mind, we envision that the RAPP will be incorporated in the GRC first time beginning with Sempra's GRC test year 2020 which Sempra will file in November 2018. Working back from that date, the RAPP proceeding will need to be concluded 12 months before November 2018 which is Nov 2017. We envision that this proceeding will take 12 months to process from filing to the issuance of the RAPP decision. So the RAPP proceeding will need to be filed in Nov 2016. We need the parties' input on the how to coordinate the timing of the RAPP with the GRC for best use of the risk assessment.

As we move along this process, the Commission may want to consider expanding this process to include the smaller utilities that are subject to the Commission's jurisdiction.

[4] PG&E has proposed a three year cycle in its application.

V. Verification

As stated above, the Commission should require a uniform and simple verification system. We note the existence of PU Code 958.5; however, this is different and much simpler. PU Code 958.5 reporting requirement focuses mainly on the review requirement. The verification report that we're looking for is for specific projects – for instance 2000 poles were authorized for upgrade at the authorized cost of $200 million. The utility when they file their NOI will also have to separately file a simple table that has five columns:

- Column 1 = what was authorized (replacement of 2,000 poles)
- Column 2 = the cost authorized ($200million)
- Column 3 = what was actually replaced (as an example let's say 1,900 were replaced)
- Column 4 = how much did it actually cost ($200 million actual spend)
- Column 5 = a narrative as to why there is a discrepancy

The Commission's Safety & Enforcement Division (SED) will be required to draft an independent verification and safety report for each utility prior to their GRC filing. The report will be based on the information that the utility provides and SED's own independent field assessment.

This proposal would require that the utility file a report at the same time it files its NOI. The report will simply be in the form of a table or chart. It should include a list of items that were approved in the prior GRC along with the cost/budget that was approved for; and a corresponding column that shows what was actual spend and actual build/upgrade. If approved does not match spend then the utility must include a narrative to explain the discrepancy, otherwise no other narrative is required or preferred. The report functions more like an audit of what the utility was approved for and what they actually spent on.

SED is not asked to testify as part of the next GRC. It will verify what the utility has claimed, issue a report detailing the verification, and provide its assessment of the existing safety-related programs.

This proposal for verification and assessment could be put into place as part of PG&E's next GT&S filing in December 2017. Given that the GT&S proceeding has no formal NOI process, it is proposed that PG&E will file its GT&S Verification Report in August 2017.

VI. How to Streamline the GRC Process

- Retain the Notice of Intent (NOI) for large utilities. ORA has greater ability to request and obtain information from utilities during NOI period, and utilities have incentive to provide that information if they want ORA to accept the NOI. Smaller utilities do not need to tender an NOI.

- Establish a 4-year GRC cycle for PG&E, SCE and Sempra. This eliminates GRC overlap for large energy utility GRCs. The year in which there isn't a PG&E, SCE or Sempra GRC can be for the PG&E GT&S plus smaller utilities' GRCs. Another advantage to having a 4-year GRC cycle is that the base year numbers are not the test year numbers from a utility's prior GRC. (4-year cycle would not require a different forecasting methodology—see recent Southwest Gas and Sempra GRCs that were on a 4-year cycle.) The 3 year rate case cycle is somewhat of a revolving door process and does not allow parties such as ORA adequate internal time to continuously evaluate the GRC process and how to best approach a case. There is currently little extra time between cases to better refine the Master Data Request and work cooperatively with the utilities on the Results of Operation model, etc. The continuous filing of GRCs leads to an inefficient process since there is little time available for either ORA or the Commission to consider much beyond what the utility is asking for as a revenue requirement and why the utility says it needs it. The inclusion of additional safety issues within the GRC process, as set forth in the OIR, further supports the 4-year GRC cycle.

- Assign 2 ALJs to large energy utility GRCs whenever possible. Explore if Energy Division is able to assign additional staff to support ALJ(s).
- Shorten the time between when ORA accepts NOI and when utility files its GRC application. Current Rate Case Plan requires minimum of 60 days. That can be reduced to 30 days or even less if the utility is prepared to file its GRC application.
- Retain the protest period. There is no advantage to eliminating it because this does not impact how long it takes for a final decision to be issued.
- Encourage settlements of GRC proceedings that are based on comprehensive, detailed settlement agreements in contrast to black box settlements.
- Encourage parties to stipulate to smaller and/or discrete issues in the proceeding if the parties are unable to reach a comprehensive settlement. This results in fewer issues for ALJ(s) to decide and may result in earlier issuance of the PD.
- Utilities should be expected and directed to provide recorded expense and capital data for the post base year in a timely manner, and in the same format in which they have provided recorded data as well as forecasts. The recorded information for the post base year provides additional information for ORA and other intervening parties to verify utility forecasts and to utilize in developing more accurate test year forecasts. This recorded information is likewise valuable to the ALJs and Commission in increasing the accuracy and confidence of its test year forecasts and the overall integrity of the final GRC decision.

VII. Next Steps

This proposal in whole is and will be an iterative process. We ask the utilities to file case studies using the RAAP process described above. The Commission will hold a three-day workshop to get stakeholder feedback and revise the proposal accordingly, or to incorporate new ideas. Once staff revises the proposal it will be re-issued and that's when we will ask for formal opening and reply comments which will be included as part of the record of this proceeding. We are not asking for comments prior to the workshop.