Staff Straw-Proposal
R.13-11-006

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?
- A description of the alternative solutions that 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.
- The cost of the risk mitigation measure that the utility proposes to address the risk.
- The priority that should be given to mitigating the risk given the magnitude of the risk and the need to assure that the utility achieves the greatest overall benefits for each dollar spent on risk reduction projects.

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.

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 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 and prioritize the risks for a safer and more resilient utility system, taking into account the cost of mitigating the risks so that utility risk mitigation projects are optimized to be affordable and cost-effective, 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.

- 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 **a uniform and simple verification** 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.

II. 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 and the cost of each of the 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.

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

safety training).[2] The utility should then optimize the sequencing of projects to optimize expenditures to assure that the risk mitigation effort will be maximally cost-effective and affordable. 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 utility assets – e.g. breakdowns in infrastructure such as old utility poles in high consequence areas; transformer failures that lead to fires; 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 cost-effective ways to control risk in ways that comport with and advance stakeholder objectives including affordability.

- 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 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 so that risk mitigation projects are prioritized so that expenditures on the portfolio are optimized consistent with best asset management practices.. 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

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

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 taking into account cost and affordability for an optimized 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, mitigation options, and the projected cost of the options, and
3. Develop a comprehensive portfolio of risk mitigation projects in which the projects are prioritized to realize an optimal reduction of asset risks with maximum cost-effectiveness.

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:

- 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.

[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 essentially focus on the proposed projects.

- Creates a clear way to identify the program risks such as operational, legacy, and emerging risks.
- Identifies the cost of each project that would address a risk.
- Create a clear methodology for optimizing the sequence in which projects would be undertaken to maximize the effectiveness of the overall portfolio of risk mitigation projects.

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.

2. Program level risk reporting – Program evaluation

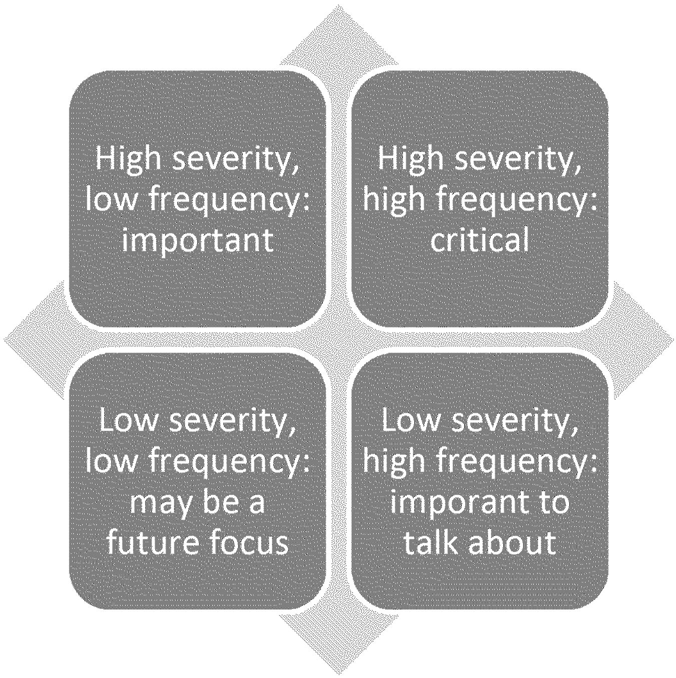
With a hierarchy in place, each and every program proposed within the GRC should be identified within that hierarchy so that risk mitigation expenditures are optimized to provide the greatest overall benefits per dollar spent. Each project should be evaluated in relation to all other projects using best asset management practices to maximize cost-effectiveness. This serves two purposes. First it informs the comprehensive system-wide evaluation of risk mitigation efforts. 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), the overall risk mitigation potential for every project within the GRC, and the cost of every risk mitigation 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. Both should be take into account along with project cost in evaluating the priority of each project within the utility's risk mitigation portfolio.

3. Portfolio segmentation & ranking graphic

In order to make an evaluation of the full portfolio of requests made by an IOU, all risk mitigation projects must be ranked to fully optimize expenditures using the best asset management practices. Since each project has already been identified and the impacts on safety and resiliency and the cost have been identified in the program summary phase, we can now optimally sequence all projects in the utility's risk mitigation portfolio.

Projects may initially be ranked as follows:



However, the cost of mitigating each risk must be taken into account in ranking and sequencing projects within a utility's risk mitigation portfolio.

The best asset management optimization techniques should be used to assure that the projects that are undertaken during the GRC period provide the greatest overall benefits per dollar spent. [Delete graph below.]

III. 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.

Currently, under D.89-01-040, energy utilities are required to submit GRC applications every three years.[4] GRCs are typically 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.

This proposal recommends retaining the three-year rate case cycle as proposed by the utilities and stakeholders at the Commission's Policy and Planning Division workshop on March 19-21, 2014, in this proceeding. The three-year cycle should be retained for multiple reasons. First, as the Commission correctly notes in its OIR, longer intervals between GRCs would increase the pressure for more Commission review and oversight for utility spending in the intervening years.[5]

Second, a longer period between GRCs would exacerbate the potential for rates to be based upon forecasts that are badly outdated. In a GRC, the utilities project a revenue requirement for a test year. Insofar as the Notice of Intent for a GRC application for a test year must be filed in August seventeen months prior to the test year (for example, in August, 2010, for a GRC for test year 2012), projections are based on recorded costs, as adjusted, for a base year that is three years prior to the test year (for example, 2009 for test year 2012).[6] If rates are approved in a GRC to cover the test year plus a two-year post-test-year period, rates in the second year of the post-test-year period (for example, 2014 if the test year were 2012) would be based upon actual recorded data, as adjusted, for a year that is five years prior to the year in which rates would be charged. (For example, rates approved for 2014 in a test year 2012 GRC would reflect recorded data, as adjusted, from 2009.)

Permitting GRC applications to be filed quadrennially or longer rather than triennially would result in GRC applications for post-test-year rates that could be based upon recorded data, as adjusted, from six or more years in the past. That is too long. Unforeseen events such as the tragic explosion in San Bruno in September, 2010, and the resulting consequences like the increase in emphasis on safety and reliability investments should be reflected in rates through a GRC in a more timely fashion.

Third, permitting the utilities to submit GRC applications outside of the three year sequence required by D. 89-01-040 could result in the Commission and parties having to address two major GRC applications at the same time. The major energy utilities in California are Pacific Gas & Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and the Sempra utilities, SoCalGas and San Diego Gas & Electric Company ("SDG&E"), which file GRC applications jointly. Having staggered GRC applications so that each utility files an application in the year in which the other two utilities are not filing an application levelizes the workload imposed by GRC applications on the Commission and interested parties.

Currently, the applications of the three major utilities are properly sequenced so that no utility files a GRC application in a year in which one of the other two utilities is also filing a GRC application. PG&E filed a test year 2014 GRC application in A.12-11-009 on November 15, 2012. SCE filed a test year 2015 GRC application in A.13-11-003 on November 12, 2013. The Sempra utilities, SoCalGas and SDG&E, are required by the decision in their last GRC to file a test year 2016 application in 2014 with their Notice of Intent being due in August, 2014.[7] Now that the Commission has the GRC applications of PG&E, SCE, and the Sempra utilities sequenced so that each utility files an application in a year in which the other two utilities are not filing a GRC application, the Commission should continue to apply the triennial filing rule for GRC applications so that the benefits of the current sequencing will be preserved.

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[4] OIR, p. 13.
[5] *Ibid*.
[6] See, e.g., Southern California Gas Company ("SoCalGas") Application 10-12-006 (December 15, 2010).
[7] D.13-05-010, pp. 1000, 1099 (Ordering Paragraph 69).

In order to maintain the three year cycle for GRCs, the RAPP should be an initial phase of the GRC rather than a separate proceeding that would conclude prior to the filing of a GRC application. Having a separate RAPP would be too time consuming.

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.
- PG&E's Gas Transmission and Storage (GT&S) = filed December 2013 for test year 2015. The next cycle begins with an application that will be filed in December 2016 for test year 2018.[8]
- 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.

Sempra GRC = the next filing is an application filed in Nov 2014 for test year 2016. ThTo 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 risk assessment phase into its GRC, we think the RAPP phase should be scheduled to conclude several months before the GRC application is filed.

With this in mind, we envision that the RAPP will be incorporated in the GRC first time beginning with the Edison and PG&E GT&S filings in 2016 for test year 2018. Working back from that date, the risk assessment phase will need to be concluded before November 2016. We envision that the risk assessment phase will take 6-8 months to process.. The risk assessment phase would conclude with a report from an independent consultant that is qualified in risk assessment and utility asset management. The utility should conduct one or more workshops on its risk assessment filing for the benefit of stakeholders and the independent consultant, and stakeholders should be permitted to file one or more rounds of comments on the risk assessment filing prior to the issuance of the independent consultant's report.

The independent consultant's report should become part of the record in the GRC. The independent consultant should be available for discovery and cross-examination, and stakeholders should be permitted to address the independent consultant's report in prepared testimony.

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.

IV. Verification

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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.

V. 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.