FILED
05-17-13
11:15 AM

Study of
Risk Assessment and
PG&E's GRC

Presented to:

The Safety and Enforcement Division
The California
Public Utilities Commission

Presented by:

The Liberty Consulting Group

May 6, 2013

65 Main Street, P.O. Box 1237
Quentin, Pennsylvania 17083
(717) 270-4500 (voice)
(717) 270-0555 (facsimile)

admin@libertyconsultinggroup.com

Overall Summary of Conclusions and Recommendations

Liberty conducted an independent review of capital and operations and maintenance expenditures proposed by Pacific Gas & Electric Company (PG&E) in its General Rate Case (GRC) filing, insofar as they address safety and security initiatives by its Power Generation and Electric Operations lines of business. We focused on PG&E's current and intended use of risk assessment to support such initiatives. Our scope excluded cyber security. Our review of Power Generation excluded nuclear operations, which meant that hydro operations comprised the primary focus of our work there. Our scope included the distribution portion of the work performed by PG&E's Electric Operations line of business.

Two principal documents formed the basis for our scope: (a) the March 5, 2012 letter to PG&E from the Commission's Executive Director, and (b) the contract under which we performed this review. We did not undertake a review intended to propose adjustments to or disallowances of PG&E's proposed safety and security initiatives. The principal areas we addressed were:

- The framework, methods, practices, and activities PG&E has used in assessing risk and relating it to proposed capital and operations and maintenance expenditures
- Whether PG&E has adequately assessed the physical condition of its power generation and electricity distribution systems
- Whether PG&E has explicitly founded proposed safety and security expenditures on explicit risk assessment processes
- Whether those processes demonstrate the appropriateness of proposed expenditures
- Whether and to what extent PG&E's proposals will reduce public and employee risks
- Whether the GRC filing supports safety initiatives with credible cost/benefit analyses
- Whether PG&E's proposed safety initiatives will reduce safety risks and whether one can determine the degree of such reduction
- Whether one can determine if additional expenditures would produce corresponding safety improvements.

The next sections of this chapter summarize the conclusions resulting from our study.

A. PG&E's GRC Filing versus CPUC Expectations

1. Conclusions

1. PG&E's 2014 GRC filing reflects the status of proposed programs and initiatives as of the first quarter of 2012. The timing of the March 5, 2012 letter meant that the structure and content of the 2014 GRC filing would not substantially exhibit the expected relationships and linkages between risk and proposed safety and security projects and initiatives.
2. The opportunities created by the March 5 letter can create a new regulatory paradigm. PG&E has not yet seized the opportunity in this new paradigm, but can do so in the future, if it can accelerate the implementation of planned incorporation of structured, robust consideration of risk as a front-end element of its integrated planning and budgeting processes.
3. The expectations created by the March 5 letter anticipate a use of risk assessment that is beyond what one finds currently in the industry. The expectations are appropriate to the circumstances, but should be accompanied by recognition that a development period will be necessary and that one can expect any "steady state" eventually achieved to fall short of producing a fully objective and completely quantified linkage between risk assessment and expenditure levels.
4. A strengthened and accelerated risk management implementation program by PG&E can bring it to a leading-edge position in the industry in terms of the comprehensiveness and use of risk analysis in driving plans, budgets, and, in turn, rate filings.
5. Risk assessments employing robust quantification of probabilities, consequences, and mitigation opportunities cannot happen at PG&E until 2014 at the earliest. Using such assessments to drive capital and O&M planning and budgeting will therefore not occur before that time.
6. It will require strong executive level structure and support, continued efforts at culture change, and an acceleration of the current rate of progress to achieve reasonably full implementation in time for the next anticipated GRC cycle.
7. Key senior leadership believes correctly that it will be several years and perhaps past the next GRC filing before the process reaches maturity. The opinions of less senior leadership are generally more optimistic.

8. The general nature of rate proceedings involving an individual company does not create an optimum environment for promoting and testing the effectiveness of the changes it will take to move PG&E toward the state anticipated by the March 5 letter. Consideration of a different context and of an approach allowing for thought of statewide consistency where appropriate will help reinforce to the state's utilities the Commission's continuing emphasis on enhanced consideration of risk assessment in connection with safety spending, promote the development of best practices, and establish useful levels of consistency.

2. Recommendations

1. PG&E should respond promptly to the March 5, 2012 letter with a proactive and specific plan and schedule for compliance with the expectations articulated in the letter.
2. PG&E should increase the organizational emphasis on risk management, recognizing and responding to the need for enhancing the pace and the "buy-in" of the business units to the new risk management program.
3. The stakeholders should consider the optimum means outside the GRC context for underscoring the long-term nature of the interest in enhanced use of risk assessment in considering safety matters and for addressing the merits of a comprehensive approach by the state's energy utilities.
4. There should be a structured, comprehensive process for providing to the Commission, regular reports of amounts actually spent versus GRC forecasts, supported by analysis and explanation of variances.

B. Proposed GRC Funding and Projects

1. General Conclusions

1. PG&E did not apply top-down spending limits that would serve to constrain development of the 2014 GRC capital and expense forecasts in the areas we examined.
2. PG&E planned for and spent well above its GRC- authorized capital and expenditure levels in 2011 and 2012, and planned to do so again in 2013, in significant part to improve safety.

3. The 2011 Electric Operations "Improvement Plan" and the "Asset Management Public Safety Acceleration Plan" applicable to Power Generation focused on safety, and drove incremental GRC electric capital expenditures and expenses for 2014-2016.
4. Narrative explanations and engineering judgment, rather than structured risk assessment processes or cost/benefit analyses generally drove GRC-proposed safety and security spending in the areas we examined. The filing generally did not provide rationales for why the chosen spending levels are appropriate and how they were determined.
5. The GRC has generally not documented how expenditures to address safety and security are in proportion to or otherwise aligned with identified risks identified. PG&E has generally not demonstrated analytically that the benefits of proposed safety and security risk mitigation measures justify their costs.

2. General Recommendations

1. PG&E should provide an improved justification and rationale for proposed GRC safety spending levels. Additional information that should be provided includes:
    - Compelling safety objectives and benchmarks that drive spending levels
    - A long term vision of what the future infrastructure looks like
    - A long term plan to achieve that vision
    - An analysis of associated rates to assure sustainability
    - Linkage of safety projects and initiatives to the achievement of long term objectives
    - Analysis / justification of the safety spending levels
        - The safety metrics that will be achieved due to the expenditures
        - Why that optimizes achieving objectives in an appropriate time frame
        - The benefits that will result
        - The benefits or consequences of more or less spending.

3. Generation Conclusions

1. The GRC projects and programs proposed do address important safety risks. Specifically, we determined that: (a) the elevation of priorities in Power Generation has been appropriate and successful, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably

justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how this can and should work in the future has emerged and the vision seems to be absolutely attainable.

2. The combination of GRC implementation (the GRC ultimately authorizes total spending, rather than spending at the project, program, or initiative level) and Power Generation's internal workings make it very unlikely that the unit's projects that actually get done in 2014 will match the GRC list very closely. Given the expectation that safety projects, programs, and initiatives will result from structured and focused risk analysis, a logical next question to examine is the degree to which it becomes appropriate to provide for some level of monitoring and accountability for expenditures and accompanying results at the same levels.

4. Generation Recommendations

1. Power Generation should modify the planning process in the future to: (a) provide allowances for new and carryover work and (b) provide the list of projects that are proposed to be deferred if less than requested funding is granted by the Commission.

5. Distribution Conclusions

1. The Electric Operations Improvement Plan, which is not founded on structured risk assessments, has nevertheless served as a driver of GRC initiatives to mitigate safety risks.
2. PG&E has undertaken strong and appropriate action to address wildfire and seismic risks for some time.
3. Addressing risks associated with electrical distribution components has been overshadowed by electric transmission and gas facilities.
4. Addressing aging infrastructure and adding SCADA to the system comprise the major focuses of safety initiatives for the distribution system.
5. Current employee/contractor serious injury and fatality levels require significantly greater mitigation. The addition of safety personnel is in line with other electric utilities and should contribute to improving field safety.

6. Distribution Recommendations

1. The two conductor replacement projects should be restructured to: (a) Complement rather than compete with each other, (b) establish program controls to contain and reduce the unit cost, and (c) develop a plan to fully assess the situation.

C. PG&E's Risk Program and Approach

1. Conclusions

1. PG&E's new integrated planning process represents a significant upgrade over its previous processes and would place the Company at the industry's leading edge. PG&E's new planning processes are innovative and well-designed to provide for better linkage of strategy and goals to resource allocation and execution.
2. PG&E lacks a defined and articulated philosophy of risk. This gap creates an impediment to reaching a common understanding between the utility and its stakeholders, particularly the Commission.
3. The lack of a mutually agreeable definition of "safety project" creates another impediment to the fulfillment of the CPUC expectations.
4. PG&E has made substantial progress in developing leading-edge corporate-wide risk assessment processes, but actual follow-through at the lines of business has lagged.
5. The 2014 GRC does not include structured and quantified risk assessments as a basis for developing capital and operating expense requests. Risk assessment processes that drive work plans and safety and security spending were researched in 2011, underwent initial development in 2012, and are just now undergoing testing as part of PG&E's planning cycle.
6. There remain corporate culture barriers that slow the process that the two business units we examined will need to fully embrace to make structured risk management an integrated part of planning and budgeting.
7. The defined governance provisions of the program are strong, but it is not clear that they are working as intended.

2. Recommendations

1. PG&E should define its proposed philosophy of risk and undertake an initiative to reach consensus on that philosophy with the Commission.
2. PG&E should develop a definition of "safety project" with concurrence by the Commission, such that the future of the program has a common basis for reporting.
3. Executive sponsorship of risk management within the responsibility of the current incumbent would be enhanced by changing his reporting from the CFO to the CEO.
4. The corporate risk organization would be significantly enhanced with the addition of a person with long and senior utility operating experience.
5. PG&E needs to recognize that the effective implementation of the program requires an inducement of culture change in how the Company assesses and uses risk considerations and a sense of greater urgency in moving toward its expected steady state.
6. PG&E should consider the addition of an "infrastructure sustainability risk" to its enterprise risks. For example: "The risk that infrastructure deteriorates (due to age and/or other factors) at a pace and to an extent that makes future recovery prohibitively expensive."
7. Corporate risk management should enhance its plans for assuring effective exercise of LOB risk functions, including efforts to ensure that risk considerations are being applied in accordance with program expectations, that appropriate risk scenarios are being examined, that monitoring of preparation and implementation of risk response plans is active, and that analysis and reporting on program status and effectiveness is meaningful and comprehensive.

D. Risk Methods and Techniques

1. General

1. The tools and techniques that PG&E is incorporating into its developing operations risk management program conform to current best practices, including:
    - A structured approach
    - Defined evaluation criteria and mechanics for scoring
    - An assessment tool linked to probability and consequences
    - The concept of inherent and residual risk
    - The conceptual approach to alternatives analysis

- A high level of effort
- A direct tie into the annual integrated planning process
- Resources and funding specifically tailored to mitigate risk gaps.

2. Generation Conclusions

1. Power Generation uses a strong Risk Evaluation Tool (RET), but the resulting risk rankings do not make the contribution one should expect. Expansion of probability and consequences rankings beyond the operation risk level to more detailed tasks would be helpful.
2. Risk scores produced through the use of the RET program lack meaning and limit the effectiveness of the tool as a means of analyzing degrees of risk and mitigation.
3. The alternatives analysis process does not appear to be meeting internal requirements, with the result that alternates do not undergo sufficient ventilation and consideration.
4. The inability to present a coherent story on the scope of the implementation work for the hydro risk, its eventual cost, its schedule, and what the hydro system looks like when it is done (*i.e.*, how the risk profile has changed), is a significant shortcoming.

3. Generation Recommendations

1. Power Generation should develop a consistent approach towards safety project/task prioritization using likelihood and consequences and applying priorities uniformly across all projects and tasks.
2. Power Generation should refine risk score methods to facilitate more effective analysis of risks and degrees of mitigation.
3. Power Generation should align the required approach with alternatives analysis in order to provide management a full range of options and suitable documentation of dismissed options is retained.
4. Power Generation should provide periodic reports that meet the standard of good project management, including credible analysis of cost, schedule, project issues, and other information needed for effective oversight.

4. Distribution Conclusions

1. The Risk and Compliance templates: (a) treat probabilities and consequences in only a partial and preliminary way, (b) base probabilities and consequences on a judgmental process, (c) encompass a small number of operational risks, and (d) include no layered approach that considers a range of potential mitigation measures.
2. The revised Electric Operations organizational structure is better positioned to address aging infrastructure and system safety issues.
3. The vegetation management program, the wood pole program, and the substation asset strategy program comprise base activities that PG&E operates effectively.
4. Since 2010, PG&E has substantially increased public outreach programs to reduce electrical contact incidents.

E. Technical Observations

1. Generation Conclusions

1. We found no concern with the effectiveness of dam safety management. It appears strong and growing stronger.
2. The issue of public safety has an appropriate place in the hierarchy of priorities.
3. Power Generation should place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.
4. The continued use of contractors as the primary production resources of the Asset Management group limits PG&E's development of internal capabilities and seems inconsistent with PG's technical objectives.

2. Generation Recommendations

1. Power Generation should in the future provide for a direct link between each identified safety project in a GRC and the risk that generated the project.
2. Power Generation should provide in Project Portfolio Management (PPM) for the preservation and use of the Risk Evaluation Tool scores throughout the life of a project. Also, these scores should have some impact, perhaps a dominant one, on the PPM ranking.

3. Power Generation should revise he PPM scoring methodology such that the resulting scores are over a manageable range and the relative values of the scores have some reasonable physical meaning.
4. Power Generation should modify PPM to facilitate the linkage of risks to projects.
5. Power Generation should review the composition of the Asset Management group with the intent of reducing reliance on contractors and strengthening internal technical expertise and capability.
6. Power Generation should adopt a more aggressive schedule for the preparation of risk response plans (RRPs). RRPs should be broken into smaller packages if the size of the package is too big to expeditiously complete.
7. Power Generation should change its approach to defining and structuring projects such that the work can be packaged in a manageable way, so management has a clear picture of the scope, cost, schedule, and intended results, and so project managers have the tools they need to effectively manage the work.

3. Distribution Conclusions

1. Several aspects of the PG&E distribution system present significant safety issues, including especially:
    - The unigrounded 12,470 volt three-wire system that serves as the predominant 12 kV configuration.
    - PG&E employs about 22 thousand miles (approximately 20 percent of primary voltage overhead distribution conductor) of obsolete #6 copper.
    - PG&E also has 47,542 miles of #4 Aluminum Conductor Steel Reinforced (ACSR) conductor on its distribution system. Corrosion issues make this conductor no longer recommended for use in coastal areas.
2. The wood pole and vegetation management initiatives, although not driven by structured risk assessment or cost/benefit analysis, nevertheless generally represent appropriate and effectively managed responses to underlying safety issues.

4. Distribution Recommendations

1. The absence of a formal distribution asset management program is a weakness that should be corrected.
2. The overhead conductor replacement program appears to suffer from higher than expected unit costs; more effective project controls should be implemented.
3. Improve the safety performance metrics by: (a) replacing the Electrical Incidents Resulting from Equipment Failure metric with the Third Party Contacts Incident metric, (b) adding $/ft conductor replacement metric, and (c) raising the bar on the 911 Emergency Response metric.

F. Response to the Commission's Seven Specific Risk Questions

1. *Will the projects reduce risk to ALARP levels?* No. ALARP is not a criterion for PG&E's risk and mitigation program, nor do we necessarily see suitable opportunities for its application. Further study of specific, limited applications would be as far as might be recommended at this time.

2. *Do projects have a credible cost/benefit analysis?* No. Costs and project justifications are included in the work papers, but a credible CBA is not. We emphasize that CBAs are problematic in areas such as safety – they are neither easy to perform, nor are they always fruitful. This does not mean they should not be addressed when practical.

3. *Was the physical condition of the system adequately considered?* It was, and exceptionally so in Power Generation. The asset management work was excellent and what started as a good effort was accelerated further on multiple occasions. The same was not so in electric distribution in the case of deteriorated conductors. PG&E has not yet fully assessed the extent of this condition.

4. *Were projects linked to a risk assessment?* Generally, no. Some projects do flow from the ERM hydro risk, but the path is not a straight line.

5. *Were a prudent set of alternatives considered for each project?* There is generally no record of such consideration.

6. *Will projects reduce risk and enhance safety?* Yes, without question.

7. *Can the degree of enhancement be quantified?* No. As with the cost/benefit issue, this is a difficult question to answer; although there is some potential here for use of the RET for this purpose.

Table of Contents

List of Acronyms

AAAC	Aluminum Alloy Conductors
ACHQ	Alternate Company Headquarters
ACSR	Aluminum Conductor Steel Reinforced (Conductor)
ADA	Americans With Disabilities Act
AEOC	Alternate Emergency Operations Center
ALARA	As Low as Reasonably Achievable
ALARP	As Low as Reasonably Practicable
ANSI	American National Standards Institute
BTL	Below The Line
CBA	Cost Benefit Analysis
CBM	Condition Based Maintenance
CIP	Critical Infrastructure Protection
CPUC	The California Public Utilities Commission
CRE	Corporate Real Estate
CRMC	Compliance and Risk Management Committee
DMS	Distribution Management System
DNV	Det Norske Veritas
DSOD	California Division of Safety of Dams
DTE	Detroit Edison
EAPs	Emergency Action Plans
EDO	Electric Distribution Operations
EMAs	Emergency Management Agencies
EP&PP	Emergency Preparedness & Public Partnership
ERM	Enterprise Risk Management
FRAP	Fire and Resource Assessment Program
FRM	Fire Risk Management
FLISR	Fault Location, Isolation and Service Restoration
GEMS	Gas and Electric Mapping System
GRC	General Rate Case

ICS	Incident Command System
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
Liberty	The Liberty Consulting Group
LOB	Line of Business
LWD	Lost Work Day
MWC	Major Work Category
NIMS	National Incident Management System
NOI	Notice of Intent
OPC	Operating Plan Committee
O&M	Operations and Maintenance
PC	Personal Computer
PG&E	Pacific Gas and Electric Company
PILC	Paper Insulation/Lead Cover
PPM	Project and Portfolio Management
QRB2	Quarterly Business Review #2
QRB3	Quarterly Business Review #3
RAT	Risk Assessment Tool
RIDM	Risk Informed Decision Making
RPC	Risk Policy Committee
RRP	Risk Response Plan
SCADA	Supervisory Control and Data Acquisition
STAR	System Tool for Asset Risk
S&S	Safety and Security
S-1	Operation Planning Session #1
S-2	Operation Planning Session #2
TGRAM	Transfer Ground Rocker Arm Main
TGRAL	Transfer Ground Rocker Arm Line
T&D	Transmission and Distribution
URD	Underground Residential Distribution
USFS	United States Forest Service

UWF	Urban Wildland Fire
VLF	Very Low Frequency
VM	Vegetation Management
#6Cu	Number 6 Copper (conductor)

List of Tables and Figures

I. Introduction

A. Structure of this Report

This report presents the results of a study that The Liberty Consulting Group (Liberty) performed for the Safety and Enforcement Division of the California Public Utilities Commission to address the risk assessment at Pacific Gas & Electric Company (PG&E) generally, and specifically with reference to its use in supporting certain safety and security projects, programs, and initiatives in the current PG&E General Rate Case filing. We prepared a description of the study's major conclusions and recommendations. It precedes this report, and provides an overall summary of study results. This detailed report begins with descriptions of the study's objectives and scope.

We then describe our study standards and criteria focused around the principal questions to which the Safety and Enforcement Division sought answers. The report focuses attention on a March 5, 2012 letter from the Commission's Executive Director to the Company. The report explains our belief that this letter creates certain expectations that, while, as PG&E concedes are appropriate, will nevertheless move not only PG&E forward, but also the U.S. energy utility industry generally. The report also explains how meeting these expectations will create a new regulatory paradigm that can benefit all stakeholders.

The report then explains our views about the connection between risk assessment and safety, the variety of ways that companies can structure consideration and analysis of that connection, how PG&E currently does so, and the direction it seeks for the future. We then summarize our overall conclusions in some detail, again focusing on the principal questions we sought to answer.

The detailed information and findings that support these conclusions lie principally in the next three chapters of this report. The first of these three chapters addresses the corporate approaches, programs, initiatives, and activities: (a) through which PG&E has used risk assessment and linked it to GRC spending requests, and (b) by which it seeks to enhance its use of risk assessment and its linkage to future plans, budgets, and eventually GRC cost forecasts. The second two address the risk assessment status and plans for the two sectors of PG&E that our work scope included: (a) the Power Generation sector of the Energy Supply unit (consisting predominantly of hydro generation), and (b) the groups responsible for the electricity distribution system, which lie within the Electric Operations unit. A final chapter addresses safety and security initiatives of other units that affect power generation and electricity distribution.

This report owes much to the efforts of PG&E, whose people fully supported our data gathering and interviewing efforts, which were substantial. This report owes equally much to the Safety and Enforcement Division, which was responsible to administer the contract. We emphasize that the opinions, conclusions, and recommendations of the report are solely the product of our team, which conducted a strictly independent study of the matters addressed herein.

B. Study Objectives

The San Bruno incident and the "lessons learned" that emerged have spurred growing support for a more aggressive approach to assuring public safety. We found this change evident at PG&E in corporate-wide programs aimed at better identification and mitigation of business risks, including those having safety implications. The Company's work took on particular momentum in mid-2011 following issuance of the report of the Independent Review Panel (IRP).

The resulting corrective activities underway as PG&E began preparations for its next rate filing made clear that public safety would have a major role in the rate case. Required spending on gas facilities was anticipated to be extremely high, and a growing interest in the public safety elements of the electric business also became apparent.

The California Public Utilities Commission (CPUC) was at the same time seeking to determine how better to fulfill its safety role. A "Straw Proposal" discussed various approaches to improving the ratemaking process to facilitate safety initiatives. This proposal served as a discussion focus for a stakeholders' workshop in January 2012. Then came a March 5, 2012 letter to PG&E from the CPUC's Executive Director (the March 5 letter). It defines a new focus on public safety for the ratemaking process, on defining system risks, and addressing the funding of risk mitigation. The CPUC decided that consultants should be retained to review the aspects of PG&E's coming GRC related to safety and security. Liberty was chosen to examine electric distribution and electric generation.

The major expectations expressed for Liberty's work included evaluating the:

- Quality of the safety and security proposals in the 2014 GRC filing.
- Degree to which safety and security proposals flow from effective risk assessments.
- Effectiveness of PG&E decision-making regarding related spending choices.

C. Study Scope

Liberty's study addressed employee and public safety and security risks that can affect safety. A definition of safety in this context has proven elusive. PG&E considers much of its expenditures related to safety and this is clearly true. The industry generally and PG&E as well tend liberally to designate expenditures as safety related. That tendency is not particularly helpful for this analysis, which seeks to focus on real initiatives directed at real risks to safety and security.

The scope of our examination included safety and security initiatives in non-nuclear (predominantly hydro) power generation and in electricity distribution (*i.e.,* excluding transmission). This scope made the Power Generation unit of PG&E's Energy Supply Line of Business (LOB or business unit) and the Electric Operations LOB the primary focuses of our work. We also looked at the initiatives of other PG&E LOBs to the extent they involved power generation or electricity distribution safety.

D. Standards and Criteria

Liberty undertook this study under the following general standards:

- *Industry best practices and standards*: much of the work associated with this project is breaking new ground; nevertheless, there is a level of existing industry practice and similar utility tasks that? also shed light on how others approach such challenges.
- *The March 5, 2012 letter*, which established a clear set of GRC expectations.
- The CPUC RFP and our resulting contract.

We focused our inquiries on the following questions, considering specific criteria, which Appendix A to this report summarizes.

BASELINE QUESTIONS ABOUT SAFETY AND SECURITY RISK

1. How have Commission expectations changed regarding analysis of safety and security risk?
2. What are the Commission's expectations with respect to connecting risk analysis with proposed revenue requirements in the filing?
3. How do those expectations compare with industry best practice?
4. How has PG&E constructed this filing differently from prior filings with respect to risk?
5. How does the PG&E GRC filing identify and quantify safety and security spending and justify the increased revenue requirements?

CORPORATE SAFEY AND SECURITY RISK MANAGEMENT

6. What changes has PG&E made with respect to risk analysis and its use since the San Bruno incident?
7. What is PG&E's expected end-state with respect to risk analyses and their use?
8. What are PG&E's plan and schedule for reaching that state?
9. What progress can one expect PG&E to have made to date, and how does that compare with what the Company has done so far?
10. Can one use PG&E's assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks?

LOB-LEVEL SAFETY & SECURITY RISK MANAGEMENT

11. Does PG&E use standard and consistent risk assessment processes?
12. Has PG&E adequately assessed the physical condition of its system (both physical assets and supporting systems)?
13. How do the LOBs identify and assess safety and security risks?
14. How have methods used and results obtained changed since San Bruno?
15. How do they compare with industry best practices?
16. How do those assessments affect budgeting for projects and programs?
17. Are changes in project and program emphases apparent?

SAFETY AND RISK IN OPERATIONS PLANNING

18. What is the overall process flow for determining operations plans and spending levels and allocations?

19. How has the operations planning process changed to reflect changes in how risks are identified and managed?
20. In what ways do corporate level activities specifically consider risks?
21. Did the process leading to the current rate filing incorporate material changes with respect to consideration of risk?
22. Are such changes clearly reflected in approved operating plans?
23. Does the planning process allow for robust consideration of risk before spending allocations and limits become resistant to change?

RISK/REVENUE REQUIREMENT NEXUS

24. What capital and O&M projects and programs in the GRC filing did the Company identify by applying safety and security considerations?
25. Are these projects founded on an explicit safety and security risk assessment?
26. Has the Company laid an adequate foundation for concluding that expenditures to address safety and security and security risks are in proportion to risks properly identified?
27. How and to what measurable extent will those projects and programs reduce identified risks?
28. Has the Company sufficiently demonstrated that the benefits of proposed safety and security risk mitigation measures justify their costs?
29. Does the degree of risk reduction reach a level that should be considered satisfactory from customer, public, and employee perspectives?
30. Can one apply PG&E's risk assessments to determine the appropriateness of related projects and programs and of the costs associated with them?

E. A New Regulatory Paradigm?

The March 5 letter creates expectations that would change the ways that we have seen utilities use risk assessment and justify safety spending in rate proceedings. We believe that centering safety and security programs on specific risks, and the degree that such risks can be mitigated, has great potential for benefitting all stakeholders. Meeting the letter's expectations will promote much greater transparency in how safety needs are identified and proposed to be met through specific initiatives. That transparency will allow stakeholders to engage in a much more robust process of valuing the benefits of expenditures, both relative to alternatives for addressing safety risks, and relative to the other risks and opportunities (*e.g.*, reliability, customer satisfaction, and environmental stewardship) that must be balanced if vital public services are to continue to remain economically sustainable.

In short, we see the March 5 letter as creating an excellent opportunity for the Company and other California utilities. PG&E has taken substantial actions in enhancing its focus on safety, but has not seized this new opportunity in the current GRC. The Company identified the specific responsive actions associated with the GRC:

- Adding risk policy testimony added to Exhibit 1 and elsewhere in the GRC testimony
- Instructing LOBs to review GRC forecasts and testimony to affirm that operating risk management was included and that the forecast closed identified risk gaps.

PG&E did not consider significantly revising the GRC forecast to address specifically the March 5 letter. Revising its GRC forecast was not consistent with meeting July 2012 target for Notice of Intent ("NOI") filing and other Rate Plan scheduling requirements. PG&E has stated that the letter did not come as a surprise; its contents were discussed at the January 2012 CPUC risk workshop. PG&E recognized that a fully mature, structured operating risk management program would only be able to occur well into the future, and only then could drive planning and budgeting of capital and operating expenditures.

The PG&E work related to safety generally exceeds the risk and public safety emphasis of utilities we have observed. It does not, however, yet meet the new regulatory expectations. The letter certainly constrained PG&E's options to respond in the GRC filing itself. Nevertheless, more than a year has passed since then, making what has been done in that period a material indicator of the quality of PG&E's response. Understanding this timing issue, we began our work focusing on measuring the trajectory of its plan for compliance as opposed to the actual level of performance achieved at that time. We became concerned, however, as our study progressed, with the lack of an apparent explanation of what PG&E viewed as that trajectory, in terms of both plans and schedules for supporting it. Moreover, we found that there was not a consensus within the Company on where it stood along that trajectory.

An overriding conclusion of our study is that PG&E needs more fully to seize the opportunities presented in the March 5 letter. The letter proposes a new paradigm – one seeking a shared objective of assuring adequate spending on public safety by advancing new risk-based techniques that will make the value of such investments more apparent to customers and other stakeholders. This approach surely will serve the Company's best interests as well. We therefore consider it of paramount importance that that PG&E respond to the March 5 letter in a structured manner, proposing a robust and energetic plan and schedule for making its future efforts in risk and safety consistent with the ideas it communicates.

F. The Nexus Between Risk and Safety

Our study focused on examining linkages between risk assessment and proposed safety and security projects and programs. We consider the requirement for a linkage to risk to present a new approach that will move not just PG&E, but the entire industry forward. That it is new certainly requires patience in developing it, and temperance in assessing how close to the ideal one can come in light of the novelty and the difficulty that applying that linkage entail. Among the benefits we see are:

- A stronger foundation for proposed work. There is no question as to why the work is being done; it is to produce specific mitigation of a specific risk.
- A better basis for prioritizing the work. If the work is linked to a specific risk with estimated consequences, it is relatively straightforward to prioritize various projects on a common scale of likelihood of the risk times the consequences.
- A measure of benefits in the form of degree of risk mitigation. Defining and quantifying cost benefits is probably the most difficult component of project evaluation. Using degree of mitigation as a quantified benefit cannot eliminate, but can ease the challenge.
- Elimination of uncertainty surrounding the definition of "safety-related." The stature and priority of real safety incentives are diluted by projects whose safety contribution is not central. Tying the definition to the risk from which the project originates makes the designation more significant.

G. An Approach to Risk

1. Framing a Risk Approach

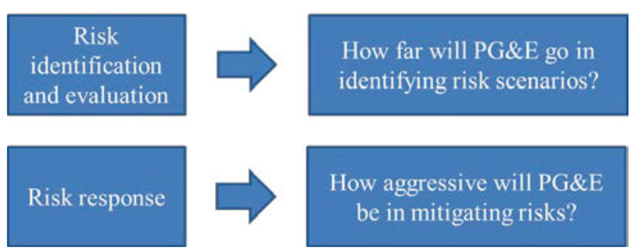
The development and use of risk management grew considerably in the industry in the 1990s, when deregulated wholesale markets demanded knowledge of how to manage commodity-related risks, such as price and credit. The concept broadened later in the industry, becoming known as enterprise risk management (ERM). PG&E has used this broadened concept since 2006. ERM looks at all business risks on an integrated basis. ERM integrates risk management with the normal utility business processes, such as planning, budgeting, engineering, and finance, for example. Risk management in this sense remains a relatively new approach for most utilities. It is common to find some attributes and methods in development. Conversations about risk often produce misunderstanding, differing levels of understanding, differing conceptual approaches, and even differing definitions of the risk management challenge.

The PG&E risk framework includes four main components.

Leadership and governance	*Risk monitoring and review*
Risk identification and evaluation	*Risk response*

PG&E has used this framework to construct a sound overall program upon that foundation. Management has devoted substantial resources and leadership in originating and sustaining the program. There exists a substantial system for evaluation of risks. It calls upon good tools and techniques. Requirements for response plans are strong, although the effort in actually producing them lags. Moreover, there are appropriate provisions for oversight, although that element of the program is also somewhat lagging.

PG&E is developing the details needed to make its program effective. The accompanying diagram shows two areas (each subject to a wide degree of choice) critical to effective implementation. These are not easy questions to answer and the notion that perhaps the answers will arrive with more experience and some degree of trial and error is reasonable.



The answers to them will define what we call a philosophy of risk. In PG&E's context it is difficult to see how all parties can be on the same page unless and until that philosophy becomes defined and generally accepted.

A consistent level of understanding must first arise within PG&E itself. Following that, establishing a common understanding with stakeholders becomes the next challenge. The questions that arise include:

- Are current LOB philosophies consistent with expectations of senior leadership?
- Are catastrophic risks being passed over or minimized in favor of less challenging ones?
- Are the mitigating actions being taken suitably aggressive?

In the absence of a clear definition of one's philosophical approach, it is difficult to respond to such questions in a structured and programmatic fashion.

2. The Role of Risk in Decision-making

All organizations consider risk in making decisions. We intuitively practice risk management in virtually every element of our lives, generally without much sophistication, or even awareness. The key variable is not whether we assess risk, but how formally and extensively we do. Focusing on these two attributes allows us to form workable definitions of approaches to risk.

Traditional

Risk influences the decision

- **Common sense**
- **May be sub-conscious**

A traditional approach, in the absence of a defined risk-management program

The absence of a formally defined risk program constitutes what we will term a "traditional approach" to management and decision-making. As it applies to public safety, this approach has served and can in many cases continue to serve the technical community well, even absent a formal program of risk management. Traditional risk consideration is informal, and usually based on common sense or judgment (typically engineering in the utility context). No specific risk standards apply; consideration of risk is embedded in the technical judgments one makes on a day-to-day basis. For example, design criteria are established, with risk becoming a function of the conservatism of those design assumptions.

Formal

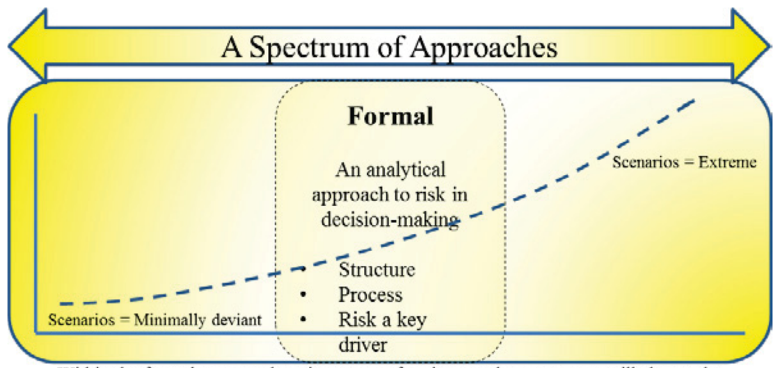
An analytical approach to risk in decision-making

- Structure
- Process
- Risk a key driver

A formal process elevates the role of risk significantly

Management that observes an increasing role for risk consideration brings greater structure, standards, and visibility to assessing and responding to it. Policies, guidelines, and expectations seek to elevate risk consideration as part of decision-making. Risk becomes a more central driver of decisions and explicit risk analysis becomes being a mandated component of management processes.

Formal programs elevate the role of risk, but can still exhibit a wide range of approaches. At the minimum end, management might simply use a fine-tuning approach, for example, stretching design criteria by some amount and then analyzing the impacts. Toward the extreme, management might require consideration of very low probability events with extreme consequences. Where one lies between the extremes begins to define a risk philosophy, measurable by the degree to which one stretches the scenarios to be considered.



Within the formal process, there is a range of options, and management will choose the approach that meets their needs and tastes.

3. ALARP

There also exists an additional philosophy that is appropriate under certain circumstances. That approach, which we will call "robust" for purposes of this discussion, gives risk even greater importance, making it the most influential business objective. The goal in such an environment is to reduce risks to a level that is considered "as low as reasonably practicable," or ALARP. In other words, the goal is always to lower risk further until it is simply no longer practical. This approach makes sense for certain business endeavors. For example, in the nuclear industry, there is continuing uncertainty on the part of many concerning the effects of low levels of radiation on nuclear plant workers. Initially, safe levels were thought to be in place, but thinking changed. Even low levels were thought to carry risk. The nuclear solution was to establish the

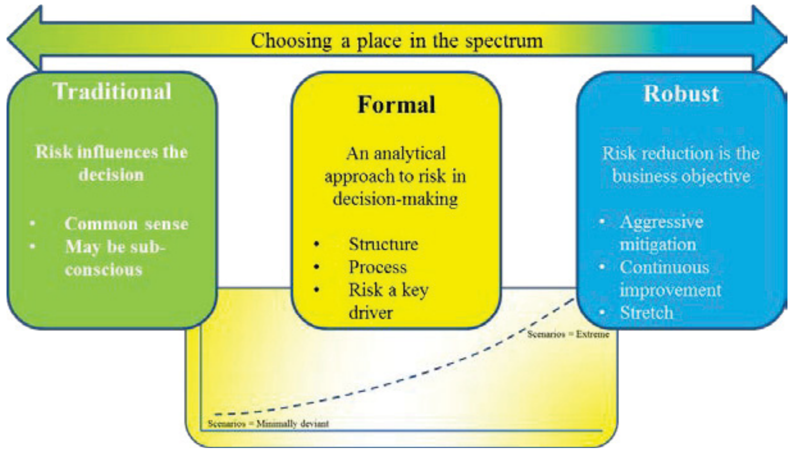
In the robust approach, risk is continuously mitigated until it is no longer practical.

principle of ALARA (as low as reasonably achievable). That approach continues to be validated in the industry.

ALARP, however, becomes problematic as one moves away from the unique circumstances for which it was originally established. The notion of never being safe enough, or risk-free enough, makes sense in certain specialized industries (like radiation protection), but surely does not apply universally. In addition, the approach is fraught with logistical problems. The "P" (Practicable), is difficult to define, and leaves openings that can undercut the purposes of the approach. In addition, the ability to balance cost and benefits is the lynchpin of ALARP, but such analyses can be extremely difficult to prepare, and are invariably open to substantive disagreement. Finally, it should be clear that such an approach can get very expensive, very fast. The desirability of substantially increasing customer rates in the name of maximizing safety raises its own set of issues. A commonly expressed ALARP notion is that added expenditures are warranted to the extent that the mitigation benefits are not "grossly disproportionate" to the associated costs. That standard would be very troubling for the electric industry. This context has long focused on a group of goals that also includes reliability, customer service, environmental stewardship, affordability and power quality (more recently), for example. Particularly important has been the strong value place on keeping a vital public commodity economically priced.

Nevertheless, there is some level of interest in ALARP in the industry. Of specific interest to Power Generation should be FERC's inclusion of ALARP in its training materials for its proposed new Risk Informed Decision Making (RIDM) initiative for dam safety, although there has been no indication of plans to implement an ALARP requirement in the future.

4. Choosing a place in the spectrum



Settling on a place in the spectrum becomes a matter of an organization's tolerance for risk and business needs. For regulated companies, however, the choice is more complicated. The preferences, tolerance, and needs of stakeholders must also be considered, and optimized through the regulatory process. Without consensus, how the utility and its stakeholders, especially its regulator, can come to a common understanding becomes unclear.

The further left one moves on the above diagram, the more one moves towards minimalist approaches, and tends to fall back into the traditional approach, thereby negating any benefits of the formal program. It serves no good end to operate an elaborate risk program, and then to constrict the nature and extent of the risks considered. This is dangerous for those choosing to operate towards the left side of the spectrum, which we believe includes PG&E, as it traditionally has in the electric utility industry. This assessment will be discussed further under "PG&E's (de Facto) Philosophy."

The matter of "philosophy of risk," or lack of such a defined philosophy, has been a focus of our study. Our discussions with the California Division of Safety of Dams (DSOD) underscore the importance of that focus. DSOD Leadership articulated the view of the risks and consequences the organization should and did confront. They centered on the possibility of a catastrophic dam failure and the potentially large resulting loss of life. There is no question of their "philosophy of risk." It demands focus down to the lowest probability risks. They further apply what might be called "portfolio thinking" to the challenge. This approach means that extremely low probability events must be considered by those responsible for a large portfolio of facilities, such as a DSOD or a PG&E. Such an approach would tend to push the organization to the events characteristic of the right side of our "formal" box.

H. Summary Responses to the Study's Key Questions

This section provides our overall answers to the questions set forth in the preceding Standards and Criteria of this report.

1. CPUC Expectations

The March 5, 2012 letter from the Commission's Executive Director to PG&E expresses substantially different expectations from those traditional in the industry with respect to the analysis of risk. That letter asked PG&E to include in its GRC Notice of Intent "the "risk assessment that underlies your rate requests." It creates the clear expectation that PG&E will perform a risk assessment, including the safety and security of its electric distribution and generation system, as part of its capital investment planning. The letter expects risk area identification and prioritization. It calls for testimony that "should encompass how safety and security are incorporated into corporate policies, goals, and culture, and the efforts being made to bolster system safety and security." The letter's expectations with reference specifically to testimony are not materially differ from what we have observed traditionally, except perhaps to the degree to which explanation is anticipated. The remainder of these expectations, however, represents a material change from how we have seen utilities explain and justify rate change requests.

Our scope of work for this study includes additional, changed expectations regarding the connection between risk analysis and proposed revenue requirements in the GRC filing. That work scope specifically includes:

- Analysis of the adequacy of PG&E's "use of risk assessment(s) in determining the appropriateness of the level of capital investment funding and Operations and Maintenance (O&M) expenditures"
- Evaluation of "whether the utility analysis includes a credible cost/benefit analysis as the basis for its recommended safety improvement options."

These two work scope elements also create expectations that reflect change in how utility rate change requests have typically addressed safety issues. These expectations require PG&E to move to a leading edge position for the utility industry. The expectations are reasonable, given the need for flexibility in the degree to which they can be accomplished fully, and in the amount of time required to reach a suitable level of accomplishment.

PG&E has been undergoing a notable increase in its management focus on safety. The GRC filing contains substantially greater narrative supporting what represent substantial increases in expenditures for safety. The filing, however, did not demonstrate fundamentally different uses of risk assessment and cost/benefit analysis, although, in the case of Power Generation, did result from a more substantial use of risk assessment in some, albeit not expansive, aspects.

The GRC filing does identify and quantify safety and security spending in reasonable detail, but we found it to overuse the "safety" label. Much of what the Company designates as safety falls under what others consider baseline and reliability work and under what we consider to be more appropriate classifications here as well.

2. Corporate Risk Management and Safety Risk in Operations Planning

PG&E has made substantial enhancements to its risk management program. The Company has expanded what was an industry-representative enterprise risk management program to include a leading edge operational risk management program. This program operates under the guidance of a new board of directors committee, whose charter and operations include regular examination of risk management activities at the corporate and LOB levels. Appropriate executive-level committees oversee risk and safety goals, programs, and results. Risk management falls under PG&E's chief audit executive. His organization includes risk management professionals who provide support for board and executive management oversight. This group also provides process support for the LOBs. These LOB executives must take direct responsibility for operations risk management activities and they have created and staffed organizations to support those activities.

This organization structure devotes significant resources and attention to risk management as a priority. Embedding responsibility in the LOBs, which have responsibility for the operations and activities that produce risk, creates a sound approach, particularly given the top-level commitment to developing its use and guiding its implementation through the use of a corporate level organization. Nevertheless, the goal of meeting the Commission's expectations more promptly would be enhanced by certain, specific changes. First, we believe that retaining executive sponsorship of risk management within the responsibility of the current incumbent would be enhanced by changing his reporting from the CFO to the CEO. The CFO demonstrates clear commitment to enhancing the use of risk management, but the need for advancing cultural acceptance of a fully robust risk management process at the LOB level suggests that its corporate "champion" operate at the highest corporate level. Inseparable from this conclusion is that we believe an independent and effective chief audit officer executive position calls for direct reporting to the CEO. Another beneficial change would be to bring to the corporate ERM organization a person with long and senior utility operations experience. This change would add credibility and therefore "clout" to what is now an ERM organization that (although staffed with capable personnel) is less senior and that is more process than operationally focused.

We believe that these changes will advance what has so far been a notable, but slower than necessary transition from a partial and "test" use of risk management to the robust use that both PG&E contemplates. Our observation is that there remain corporate cultural barriers that slow the process by which the two business units we examined are fully embracing the process. The steady state that PG&E anticipates will include a strongly analytical use of risk assessment. However, it is only now, quite some time from the San Bruno incident (and a year from the March 5 letter), testing a process that will make risk assessment at the enterprise and operational levels a strong contributor to the new integrated planning process that drives PG&E budgeting for capital and O&M expenditures. When fully operational, this process will incorporate leading edge risk assessment at the front end of planning; *i.e.*, before allocation of capital and expense spending. Equally important, this steady state is intended to produce direct and strong linkages at the back end; *i.e.*, risk assessment will be a material driver of integrated operations planning and budgeting, which will directly drive GRC funding requests. This linkage, as designed, has promise in getting PG&E as far as can be reasonably expected in meeting the regulatory expectations that have focused our work in this study.

While strong and sufficient in concept, much time remains for PG&E to reach its expected steady state. It is only now (April 2013) testing the new risk assessment module of its integrated planning process. Senior executive management's expectations (and we consider them reasonably accurate under current circumstances) are that it will be several years, and perhaps past the next GRC filing, before the process reaches maturity. Interestingly, and of concern, is the more optimistic belief we found among some personnel that the process may be close to fully shaken out by the time the April 2014 risk assessment sessions take place. That belief must reflect an understanding that what is being sought is much less aggressive than what we believe top management actually intends and what the regulatory expectations creates. We recommend that PG&E recognize its needs as including the inducement of both culture change in how the Company assesses and uses risk considerations and a sense of greater urgency in moving toward its expected steady state. These recommendations do not reflect strong criticisms of what PG&E has done so far, recognizing that it is charting new territory for the industry. Rather, they reflect what we believe is necessary to demonstrating a commitment to meeting what we would agree are reasonably aggressive expectations, albeit reasonable stakes to plant in the ground under the circumstances.

These expectations and markers will move the industry forward, raising two important questions:

- How will they play out in the cases of other California utilities
- How will the Commission remain engaged as new territory is charted, lessons are learned, and expectations become calibrated to growing experience?

If changes at issue for PG&E are beneficial, it would appear that others will gain advantage from at least some material part of those changes as well. In addition, sustaining momentum in this area of significant originality will also benefit from continuing stakeholder engagement at times other than GRCs. Moreover, we perceive that the traditional focuses and significant contest of rate proceedings make them a difficult venue for crafting new regulatory approaches or emphases. Thus we consider it likely that creating a formal structure for promoting industry-wide dialog and sharing of experiences (and experiments even) will go a long way to demonstrating to PG&E and others that risk assessment remains an important objective and that moving the state's entire utility industry forward on a reasonably common basis is significant.

Returning to where things lie now, we observe that, despite material progress by PG&E, it remains the case that one cannot now use PG&E's risk assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks.

3. LOB-Level Safety & Security Risk Management

PG&E has created a structure that will call for its LOBs to use standard and consistent overall risk assessment processes. Corporate and LOB-level organizations, which have created and emphasized common processes, support the development of such processes. There is uneven implementation of them at present, with Power Generation ahead of the Electric Operations distribution segment in developing them. This gap stands to reason, given the external and organizational environment in which Power Generation operates. That environment includes the very heavily safety-regulated nuclear power environment and the lesser, but still substantially safety-related hydro facility environment Liberty's study focused on hydro operations in PG&E's Power Generation LOB. Nevertheless, while progress has been made in both groups that we examined, April 2013 will begin an important test of a more robust use of risk assessment in planning, and top management appears keen to use that learning process to continue moving to the steady state it anticipates for linking risk assessment ultimately to GRC proposed funding levels.

PG&E has generally assessed the physical condition of its system (both physical assets and supporting systems) adequately, but exceptions in Electric Operations include the need for greater attention to cause assignment for system incidents and events and for the adoption of a more formal asset management approach. Assessment of safety and security risks is moving in both LOBS we examined toward a more structured, quantified risk assessment process that seeks to incorporate more quantitative assessments of probabilities and consequences, and to identify a more robust range of mitigation measures and their costs and benefits. Both have ground to cover, as the later, more specific discussions associated with each address.

In neither case did we find the efforts of these two units substantially deficient with respect to what we have observed in the industry. We did, however, find in the case of electricity distribution instances where the state of its infrastructure has not kept pace. On a related matter, we believe that aging infrastructure makes this issue an important risk even apart from strict safety concerns, although we do see a connection between the reliability issues such infrastructure imposes and potential safety consequences. PG&E's infrastructure is probably in some respects newer than that of other utilities, whose conditions make this issue one, in our view, of significant nationwide consequence. However, as PG&E's senior leadership observes in GRC testimony, the Company recognizes that historical levels of expenditure and current system conditions make this an issue here. Our scope did not include an examination of the reliability and quality issues that serve as a principal driver of the aging infrastructure issue. Nevertheless, our observations of and about the system from a safety perspective lead us to agree that addressing aging infrastructure through a long-term program appears to be an important priority. We particularly noted the issue in our work associated with the distribution system, but the age of PG&E's hydro assets makes the issue pertinent there as well.

We did observe an increased emphasis on safety expenditures as proposed both for Power Generation and electricity distribution. We observed a greater use of risk assessment by the former in advance of the GRC, but for neither of the two units could we observe clear and strong connections between risk assessment and GRC budgeting for projects and programs. We did find in both cases that project and program emphases do address clear safety issues, and that the expenditures appear designed to mitigate properly identified and material safety risks.

4. Risk/Revenue Requirement Nexus

We were able to identify what GRC capital and O&M projects and programs PG&E identified by applying safety and security considerations. We found that an overly liberal use of the "safety" tag applied -- no doubt influenced by the focus on safety created by the March 5 letter and other circumstances. We did what we could to isolate those programs that in our judgment were truly driven predominantly by safety and security concerns, as opposed to other factors, such as reliability, compliance with other public requirements, or simply consistency with sound baseline utility operations.

Having made this categorization, we could not identify any that PG&E had founded explicitly on structured, analytically founded risk assessments. Our conclusion in this regard was supported by the acknowledgement of senior LOB leadership that engineering and other professional judgment formed the basis for deciding what initiatives to pursue and at what levels of proposed expenditure. We queried PG&E about it's the adequacy of its foundation for concluding that expenditures to address safety and security and security risks are in proportion to risks properly identified. We could not find substantial documentation of this type of thinking or analysis, although we consider such support to be consistent with the expectations created by the March 5 letter and by the areas of inquiry included in our scope for this study. We, like PG&E, consider those expectations to be appropriate under the circumstances, and are cognizant of the fact that substantially satisfying them will "advance the ball" from an industry-wide perspective, will take time, and will likely require modulation based on experience gained as time moves forward.

We also did observe a measurable way of determining on a quantitative basis, from the work that PG&E has shared with us, the extent to which those projects and programs can be expected to reduce identified risks. Similarly, the Company has not demonstrated analytically that the benefits of proposed safety and security risk mitigation measures justify their costs. We asked PG&E specifically about such analyses. The response was that none had been prepared to support the GRC as filed. We learned that relevant documentation may now be under preparation. We trust this is so, but find it surprising that, a year after the March 5 letter, it remains incomplete. We, like others, will presumably have to await responsive PG&E evidence in the GRC to determine the relevance and address the substance of that documentation.

Given the circumstances, we could not assess whether the degree of risk reduction can be expected to reach a level considered satisfactory from customer, public, and employee perspectives. Nor could we apply any PG&E risk assessments to determine the appropriateness of related projects and programs and of the costs associated with them. As our report makes clear, however, we do generally believe (fairly narrow exceptions are noted in this report) that PG&E has tailored specific and responsive GRC projects and programs to known and reasonably identified safety and security risks. Moreover, those projects and programs are reasonably designed to mitigate those risks.

5. LOB-Specific Conclusions – Power Generation

The Energy Supply LOB has responsibility for internally-owned generating facilities and contracts for power. It includes Nuclear Generation, which operates the Diablo Canyon plant, but our study scope excludes that area of operations. We focused on Power Generation, which operates all of the non-nuclear, PG&E-owned generation. From a safety perspective hydro operations are the most significant of Power Generation's assets; they were our primary focus. Power Generation's GRC-proposed capital and expense spending levels are both more than 30 percent higher than the corresponding 2012 levels. One cannot accurately define which portion of the spending goes to safety and security projects because of the lack of a satisfactory definition. However, it is clear that a large share of the increase relate to projects categorizable as safety-related under any reasonable definition.

The Power Generation organizations have made significant strides in addressing safety in the past two years. Power Generation's development and implementation of a risk assessment process has led to: (a) an extensive review of infrastructure, leading in turn to (b) a large amount of physical work to mitigate safety risks associated with, among other things, aging facilities. Supporting this physical work have been technical analyses, particularly by the Power Generation Asset Management organization, as well as implementation of numerous risk assessment tools that have helped focus priorities.

Power Generation is relatively more advanced than Electric Operations (for electricity distribution) in the use of risk assessment processes. The tools and techniques of PG&E's program are sound, and, in principle, reflect best practices. It is not clear, however, that these tools (for example the Risk Evaluation Tool) are being used to their full potential. Risk scoring and ranking occur, but we did not observe substantial use for them in prioritization efforts. Power Generation uses a process of "alternatives analysis" in seeking mitigation options, presenting assessments of feasibility, implementation barriers, schedule for implementation, cost of implementation, and the degree of risk reduction expected. This process is sound, but appears to be used more to report on decisions already made, rather than to support decision-making itself.

Large dams do not lack for attention. Power Generation makes extensive use of consultants and outside panels. Regulators are active in meeting their oversight responsibilities. In addition, safety criteria and regulatory oversight tend to grow with time, producing an element of continuous improvement in terms of managing and lowering risks. We found no reason to question the effectiveness of dam safety management; it is strong and growing stronger.

As is true for electricity distribution, Power Generation should operate on the basis that aging infrastructure rises to an enterprise-level risk. Many components of the hydro system are at an advanced age. This feature presents real risks for things "wearing out," particularly recognizing that standards by which old facilities were built are often inferior to current standards. In addition, improving Risk Response Plans (RRPs) should be a priority for Power Generation. Energy Supply set a goal of issuing only one such plan in 2012, but did not meet it. The one RRP goal has been extended to April 2013, with the balance of operational risks due by the end of the third quarter 2013. Power Generation needs a more aggressive approach to completing these plans.

Liberty examined the question of how Power Generation conducted for the GRC the process of "drawing the line" on spending at some appropriate level. We sought to determine how it decided what aggregate level of spending makes the most sense and which proposals to delete or defer. We were unable to identify how that process was conducted or, more importantly, what rationale governed the final choices. In addition, the combination of the GRC process and Power Generation's internal workings make it unlikely that the projects that actually will get done in 2014 will match the GRC list very closely.

We identified the need for modifying the planning process in the future to: (a) provide allowances for new and carryover work, and (b) provide the list of projects that are proposed to be deferred if less than requested funding is granted by the CPUC. Such an approach will go a long way towards creating a much-improved understanding of the work that can be accomplished. It will also provide a more realistic base from which to monitor performance against plans. A similar need exists in the case of electricity distribution. On a related issue, we believe that there should also be a process for providing to the Commission, regular reports of amounts actually spent, supported by analysis and explanation of variances.

We did conclude, after reviewing projects and expenditures by Power Generation category that the GRC projects and programs proposed do address important safety risks. Specifically, we determined that: (a) the elevation of priorities in Power Generation has been appropriate, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how linkage can and should work in the future has emerged and the vision seems to be absolutely attainable. The one major question hanging over all of this is the aggregate level of spending, whose rationale and justification remain clouded.

In summary, we believe that the proposals will mitigate observable safety risks; however, we also concluded that Power Generation needs to provide improved justification and rationale for the proposed aggregate level of expenditures for safety initiatives. The proposed increase in spending is substantial, especially when viewed as increases in safety-related spending. The GRC, however, lacks a rationale for why the chosen aggregate spending levels are appropriate and how they were determined.

The issue of public safety has an appropriate place in Power Generation's hierarchy of priorities. There is a Public Safety Officer, whose staffing will be augmented by two additional people. A new comprehensive public safety program has been created. Public safety metrics and benchmarks are not in widespread use; many of the hazards posed by Power Generation's facilities are unusual. Nevertheless, Power Generation continues to work on development of such metrics. There has also been a substantial increase in safety emphasis at the corporate level. However, what once was an improving trend in incidents has turned more negative.

In the area of emergency management, Power Generation structures its approach around the National Incident Management System (NIMS). Power Generation people are trained and drilled in this approach and are well-versed in its requirements. Power Generation maintains close coordination with local emergency management responders. Power Generation has extensive experience and capabilities in emergency management and no issues are apparent.

6. LOB-Specific Conclusions - Electricity Distribution

The reorganization of responsibility for electricity distribution and the creation of a Distribution Asset Strategy and Reliability have increased focus on distribution infrastructure issues affecting safety. Electric Operations, however, does not yet operate a formal asset management program addressing its distribution system. We recommend the establishment of one. These types of programs force a detailed and thorough condition assessment survey of the major assets, and take failure modes into consideration. Long term sustainable plans can then be prepared to address the asset conditions. A sustainable asset management will mitigate system safety risks from aging infrastructure, which constituted a major portion of the safety items in this GRC.

We also recommend particularly for the electric distribution that PG&E treat aging infrastructure as an enterprise-level risk. Aging infrastructure is an issue for U.S. utilities and industry in general, in both the government and privately owned spheres. It is too easy and it has been too common for utilities to put off the replacement to reduce new investment. As replacements are delayed, the magnitude of the financial implications of getting behind becomes too severe to overcome. Safety risks can also develop. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets.

Several aspects of the PG&E distribution system present significant safety issues for the Company:

- The unigrounded 12,470 volt three-wire system that serves as the predominant 12 kV configuration. Very few utilities use similar three-wire systems. They cause downed lines often to remain energized until a dispatched PG&E Troubleman can respond on site.

- PG&E employs about 22 thousand miles (approximately 20 percent of primary voltage overhead distribution conductor) of obsolete #6 copper. The small size of this once popular conductor makes it comparatively more subject to breakage as it ages.
- PG&E also has 47,542 miles of #4 Aluminum Conductor Steel Reinforced (ACSR) conductor on its distribution system. Corrosion issues make this conductor no longer recommended for use in coastal areas.

Issues such as these also present significant reliability issues. There exists in electricity distribution a very significant overlap between reliability and safety issues. In many cases, reliability concerns should drive enhancements before safety concerns become critical. However, PG&E, like the rest of the industry, faces substantial aging infrastructure issues. We did not undertake an independent analysis of the system from this perspective. The evidence of PG&E's CEO, however, acknowledges the problem, and those observations we did make in performing our examination of system safety issues support a concern about this issue.

The use of risk analysis extends beyond safety. It is important that PG&E also use it to address reliability and safety (among other goals, such as customer service and environmental stewardship). The Company needs to do so in a manner that allows risks associated with all applicable goals to be analyzed, prioritized, and addressed through appropriate initiatives in a balanced manner. The longer a utility takes to address aging infrastructure, the more reliability and safety issues emerge, and the more difficult it becomes to support initiatives in a manner that maintains a sustainable rate trajectory. We believe it is important for the Commission to assure that, as focus on safety increases, the need for addressing infrastructure from the reliability and rate trajectory perspectives remains at the forefront as well.

Through 2011, formal consideration of electricity distribution risk took place under an overall ERM program that, like the programs of most utilities, focused primarily on top corporate risks, but did not apply structured, comprehensive analysis of operating risks. In 2011, following the San Bruno incident, Electric Operations changed its approach to considering risk along two tracks:

- Employing PG&E's expanded ERM program to incorporate more structured consideration of operational risks.
- Forming the Electric Operations Improvement Plan, which has not incorporated formal risk assessment, but which has generated a focus on immediate actions that could mitigate known risks.

Activities under the first part of the revised approach have been proceeding, but not at a rapid pace. The charter for the Electric Operations Risk & Compliance Committee came in November 2012, followed in December by the LOB's first register of key operational risks, with the items listed still under evaluation. Through the preparation of the GRC, the Electric Operations Improvement Plan, which is not founded on structured risk assessment, has served as a driver of initiatives to mitigate safety risks. The Improvement Plan, however, does explicitly address projects and programs designed to address public and employee safety.

Electric Operations is just now reaching a foundational milestone in the use of more structured operational risk assessment. It has just completed (for use in senior management Operations Planning sessions scheduled for this April) its draft Risk and Compliance (formerly called "Session D") templates. These templates do chart some risks on the basis of probabilities and consequences, but in a partial and preliminary way. Quantification of probabilities and consequences flowed from a judgmental process, only a fairly small number of operational risks have been included, and there is no layered approach that considers a range of potential mitigation measures and levels of effort (and accompanying costs and reductions in risk). The template does not support an analytical approach to identifying the costs and benefits of a range of mitigation measures.

Both senior executive and LOB management consider this April's Risk and Compliance sessions to represent a test case for implementing a more analytically based consideration of risk and including it as an integral part of Operations Planning, which drives budgets, and in turn future GRC filings.

We analyzed the distribution expenditures detailed in PG&E's GRC Exhibit 4. We did not agree with the Company's identification of those that can be considered "safety-related," as we would define the term. We asked PG&E to reclassify expenditures according to our structure. Many of the electric distribution initiatives in the GRC comprise fairly straightforward infrastructure replacement projects. For the vast majority of them, like-for-like replacement is the only feasible alternative, making replacement timing the predominant variable. Over 88 percent of the identified GRC system safety initiatives consist of replacing aging infrastructure and adding SCADA capability. This result conforms to the stated direction of the Electric Operations Improvement Plan. We also found that the electric distribution safety initiatives comprise main contributors to increased costs above 2011 levels. While identified safety initiatives constitute less than twenty percent of the electric distribution GRC items, they represent increases of over 300 percent from 2011 expenditure levels. By contrast, items associated with reliability, base operations, and support show an increase of about twenty percent over recorded 2011 expenditures.

GRC Exhibit 4, Chapters 2-4 addresses a number of technology safety initiatives. They were not derived from or supported by structured risk assessment or cost/benefit analysis. They will contribute to mitigating system safety risks by addressing gaps in asset records, information management systems, and emergency response. The degree to which they do so cannot be determined from the GRC or from other information made available by PG&E.

GRC Exhibit 4, Chapter 5 addresses distribution maintenance initiatives. They too were not supported by structured risk assessment or justified by analyses of their costs and benefits. However, with one exception, we found them to be sound programs that appear to be effective and properly managed programs that mitigate identified safety risks. Those that we found effective were those addressing:

Preventive maintenance patrol and inspection
Enhanced wildfire patrol
Infrared inspection
Underground oil switch replacement
Underground enclosure barcode
Network high-rise transformer replacement
Network CBM
Network SCADA
Swiveloc manhole replacement

The exception involves conductor replacement under the infrared program. Portions of that replacement program compete with rather than complement the conductor replacement in Exhibit 4, Chapter 15.

We did not find the initiatives of GRCV Exhibit 4, Chapters 6-8 to be driven by structured risk assessment or cost/benefit analysis, but they generally represent appropriate and effectively managed responses to underlying safety issues. These initiatives include the wood pole inspection and maintenance program and the vegetation management program. We also found that the fire risk reduction program could potentially reduce wildfire risk. The American National Standards Institute (ANSI) published a new standard for tree risk assessment in late 2011. PG&E has modeled its program after this voluntary, best-practices standard.

Again, we did not find underlying risk assessments or cost/benefit analyses for substation assets, and reliability initiatives addressed in GRC Exhibit 4 – Chapters 13 to 15. We did, however, find those programs to be contributors to mitigating safety risks, subject to several concerns.

We found the substation asset strategy programs to be effectively managed. We observed no unaddressed safety risks. We also found that the conductor replacement program addresses a serious safety issue. Its ultimate costs, however, are likely to extend well beyond the amounts reflected in the GRC. The impacts of conductor failures are magnified by the large percentage of downed conductors that remain energized. Electric Operations has yet to assess fully the magnitude of the deteriorated conductor situation. The forecast levels for the Chapter 15 replacement did not follow a sound assessment of system conditions.

We also found the unit costs of Chapter 15 replacement to be high. The main cost driver appears to be the lack of identification of a suitable replacement conductor. Rather than replace the conductors with equivalent ampacity wires, divisional engineers have often installed upgraded feeder conductors, such as 4/0 aluminum. More effective program controls are in order.

PG&E's two different conductor replacement programs appear to compete with, rather than complement each other. The Chapter 5 Maintenance conductor program looks for three splices in a span. These splices will generally only occur when the conductor has had past breaks. The Chapter 15 Reliability conductor replacement program targets conductors on the primary basis of outage history. This history also tends to identify conductors that have often been spliced. It would be more appropriate to make the infrared and associated splice registry strictly an identification program rather than replacing conductor one span at a time.

7. Response to Specific Engagement Questions

The scoping documentation for our study contains seven general questions relating to the overall technical adequacy of PG&E's work addressing safety matters in this GRC. They are discussed throughout this report, but we respond to them here in overall summary form.

Will the projects reduce risk to ALARP levels? No. ALARP is not a criteria for PG&E's risk and mitigation program, nor do we necessarily see suitable opportunities for its application. Further study of specific, limited applications would be as far as might be recommended at this time.

Do projects have a credible cost/benefit analysis? No. Costs and project justifications are included in the work papers, but a credible CBA is not. We emphasize that CBAs are problematic in areas such as safety – they are neither easy nor are they typically fruitful. This does not mean they should not be addressed when practical.

Was the physical condition of the system adequately considered? It was exceptionally so in Power Generation. The asset management work was excellent and what started as a good effort was accelerated further on multiple occasions. The same was not so in electric distribution in the case of deteriorated conductors. PG&E has not yet fully assessed the extent of this condition.

Were projects linked to a risk assessment? Generally, no. Some projects do flow from the ERM hydro risk, but the path is not a straight line.

Were a prudent set of alternatives considered for each project? There is generally no record of such consideration.

Will projects reduce risk and enhance safety? Yes, without question.

Can the degree of enhancement be quantified? No. As with the cost/benefit issue, this is a difficult question to answer; although there is some potential here for use of the Risk Evaluation Tool (RET) for this purpose.

II. Corporate-Level GRC and Risk Processes

A. The Operations Planning Process

PG&E's Operating Planning process underlies its GRC filing. This process embeds current and planned use of risk analysis to the extent relevant for GRC purposes. We examined the nature and degree to which safety risk assessment underlies PG&E's current GRC filing. The "Operating Planning" process has served as a primary driver of safety-related spending following the September 2010 San Bruno incident. The process has changed since that time and its operation this year is bringing an increased focus on the consideration of risk in plan development. The evolution of the process is important in understanding the risk-based underpinnings of the current GRC, and how those underpinnings may change in the future.

1. Operating Planning for 2011-2013

PG&E's Operating Planning processes have served as the principal source of budgeting. The operating plans have included a one-year budget and two additional plan years. This planning regime was in effect during 2011 and 2012; *i.e.*, the first two planning years following the San Bruno incident. Significant incremental safety expenditures occurred during these years. The rates in effect during these two years were the levels authorized in the Company's 2011 GRC, settled in May 2011.

PG&E recognizes the authorized levels of capital expenditures and operating expenses in place from the previous GRC case in its operating planning. The Company manages to these levels of expenditures in its annual operating plan or budgeting process. The operating plan is usually based upon capital and operating expenses near the indicative authorized levels from the GRC, with a general goal of earning the authorized return on equity for the relevant budget year. Operating plans build from the bottom-up for each LOB, based upon work plans developed in each area. An operating plan committee (OPC) consisting of the president and CEO, the CFO and the vice president finance and planning serves as the governing body that receives and authorizes the bottom-up budgets from each LOB. The operating plan process concludes with an approved final budget and "budget letters" to each LOB that officially authorize specific spending levels for each area. The proposed budgets are presented to and approved by the Company's Board of Directors at their December meeting.

a. 2011 Planning Cycle

The PG&E operating planning process for the 2011 budget year began shortly after the September 2010 San Bruno incident. Budgeting was to be performed using a new prioritization process and budgeting template. The Company had declared a deadline of 2014 for achieving the vision of becoming the "leading utility" in the United States. PG&E defined leading utility as first quartile performance for "energized employees" and for "rewarded shareholders," and first decile performance for "delighted customers" and environmental leadership. Twenty-five key drivers to reach these four goals served as 2011 focus areas. The planning focus was the 2011 budget year, with the following two years of the three-year operating plan to be constructed in early 2011.

The LOBs developed their 2011 requests based on the planning guidelines and templates and prioritization requirements. No CPUC decision on the 2011 GRC had yet occurred. The originally approved 2010 budget thus served as the original generalized target for capital and operating expense spending levels. Planning guidelines specifically instructed the operating LOBs (Electric and Gas Transmission and Distribution, Customer Care and Energy Supply) to prioritize projects and amounts above 97 percent of 2010 budget levels. All non-operating units were to prioritize above 93 percent of their 2010 budget level. Work and spending below these levels was not required to be prioritized. Safety was not then a "top 10 goal." The CEO had also yet to issue his 2011 request for "turnaround plans" related to safety from the operating LOBs.

PG&E's 2011 budget levels for expenses were about $37 million more than the regulatory authorized levels. Capital expenditures were budgeted at $2.355 billion, or about $115 million greater than regulatory authorized targets. PG&E spent significantly greater than both budgeted and authorized regulatory levels for both capital and operating expenses in 2011. According to the Company, the greatest amount of incremental capital expenditures occurred in gas transmission related to San Bruno and in gas distribution and customer care. The Company also cited higher storm activity as requiring more spending by Electric Operations. Some electric

2011 spending was reallocated following the establishment of an Energy Supply turnaround plan and an Electric Operations improvement plan during the second half of the year.

The next table shows that PG&E spent $21 million more in 2011 than the regulatory authorized level for expense, and $16 million less than budgeted. PG&E spent $264 million more capital dollars than the regulatory level and $148 million more than budgeted.

2011 Budgeted vs. Actual Expenditures

2011 BUDGET VS. ACTUAL EXPENSE BY LINE OF BUSINESS
2012 BUDGET BY LINE OF BUSINESS
(MILLIONS OF DOLLARS)

		Expense					Capital				
Line No.	Line of Business	2011 Imputed Regulatory Targets	2011 Budget	2011 Actual	Budget vs. Actual (%)	2012 Budget	2011 Imputed Regulatory Targets	2011 Budget	2011 Actual	Budget vs. Actual (%)	2012 Budget
1	Gas Distribution	$680.0	$144.7	$153.5	6.1%	$221.7	$1,435.1	$251.6	$302.7	20.3%	$380.2
2	Electric Distribution		535.0	553.6	3.5%	553.2		1,162.5	1,225.6	5.4%	1301.3
3	Customer Care	450.8	433.4	427.1	-1.5%	470.9	101.3	106.0	108.4	2.2%	136.3
4	Nuclear Generation	328.8	309.4	313.0	1.2%	336.6	133.9	211.9	233.5	10.2%	260.6
5	Power Generation	193.9	181.0	169.2	-6.5%	193.5	173.8	238.2	258.7	8.6%	268.6
6	Energy Procurement	60.5	54.0	50.4	-6.6%	52.0	–	–	–	–	–
7	Support Orgs and A&G	575.7	651.8	643.5	-1.3%	689.7	395.0	384.5	374.0	-2.7%	506.3
8	Subtotal	$2,289.6	$2,309.3	2,310.3	–	2,517.6	2,239.2	2,354.6	2,502.9	–	2,853.3
9	Reserve	–	17.1	–	–	52.4	–	–	–	–	–
10	Total	**$2,289.6**	**$2,326.4**	**$2,310.3**	**-0.7%**	**$2,570.0**	**$2,239.2**	**$2,354.6**	**$2,502.9**	**6.3%**	**$2,853.3**

Notes: 1. 2011 imputed regulatory targets for gas and electric distribution are combined to be consistent with previously reported information in the 2011 GRC.

The Electric Distribution organization overspent its 2011 expense budget by $18.6 million, or 3.5 percent. The largest drivers were increases in underground inspections and storm-related emergency service restoration work. Electric Distribution overspent its 2011 capital budget by $63.1 million or 5.4 percent. Increases were primarily driven by higher than planned WRO projects and higher-than-planned units of work for overhead conductor replacement, breaker replacement, and overhead maintenance.

The Power Generation organization underspent its expense budget by $11.7 million or 6.5 percent. Power Generation's capital expenditures were $20.5 million or 8.6 percent greater than budgeted, largely due to increases in safety-related and regulatory projects. These increases were partially offset by delays in FERC license issuance and related project work and a reduction in capital work at the Helms power plant.

b. 2012 Operating Planning Cycle

The 2012 planning cycle differed from that of the previous year. Planning and forecasting for the years 2014 through 2016 for the next GRC filing was to be initiated as part of this process. The processes commenced with the issuance of planning guidelines in August 2011 as part of Quarterly Business Review #2 (QBR2). This first set of guidelines and instructions focused on the 2012 budget year, but also requested from the LOBs plans for 2013 and 2014. The plan and forecast for the three years was to be established first; GRC planning was eventually separated from this initial effort and refined for the rate case period on its own path and separate process.

The QBR2 planning instructions took a general nature, especially when compared with planning instructions for the previous and following years. The bottom-up plans from the LOBs were to include "plan work, resources, and budget" sections. Each LOB had to define a business overview, its initiatives, their alignment with 2012 to 2014 goals, the major work initiatives and programs to be completed over the next three years, key performance indicators and LOB metrics, and an update on enterprise risks falling within each LOB. ERM risk analysis would not finish prior to the September 2011 due date for the work plans. The Company's formal operating risk management processes and techniques had not been developed or rolled out at this time. The reference in the planning instructions was to enterprise risks that each LOB "owns."

Each LOB's plans also had to include a resource section identifying the specific workforce strategy for each LOB. Proposed budgets were required to show significant changes from the 2011 original budget. LOBs presented requested funding for 2012 through 2014, along with the prioritization methods used and the risks associated with funding levels below the 2012 request. The utility strategic plan, "Road to 2014" goal drivers, the enterprise risk management template, and 2012 and 2013 preliminary capital and expense targets served as reference materials.

The resulting operating expense forecasts through 2014 and capital expenditure forecasts through 2016 came in September and October of 2011. For 2012 planning, Electric Operations and Energy Supply submitted multi-year financial outlook documents. These documents included 2008-2010 actuals, 2011 budgets, 2012-2016 initial requests, and various year-over-year comparisons at the program and major work category (MWC) level. October 19, 2011 budget letters set total GRC expenses of $2.306 billion and capital expenditures of $2.863 billion.

c. Conclusions

PG&E planned for and actually spent above its rate case authorized capital and expenditure levels in 2011 and 2012, partly to improve public and employee safety. PG&E used rate-authorized levels of capital and operating expenses for the years 2011 to 2013 as set in its 2011 GRC. However, the Company spent more than its rate-authorized levels during the past two years following the San Bruno incident.

PG&E's approved 2012 capital expenditures budget was $445 million above rate-authorized levels, and $800 million of capital spending above authorized levels is planned for 2013. PG&E's financial results in 2011 and 2012 have been poor, with 2013 projected to be even worse than the previous two years.

PG&E's normal practice with regard to budgeting is to target its annual spending levels near its GRC-authorized levels. Doing so allows a return on equity near authorized levels to be attained. However, the San Bruno incident and the following IRP and Blacksmith Group reports changed this dynamic for 2011-2013. Capital and operating expenditures driven by safety responses in the operating LOBs increased in 2011. The safety "turnaround plans" for the LOBs requested by the CEO in mid-year 2011 increased safety and security spending for 2012 and beyond.

2. 2014 GRC Planning Process

a. GRC Process and Guidance

PG&E's 2014 GRC sets revenues to fund electric and gas distribution, utility-owned generation and corporate service organizations' operating and capital costs for the years 2014 through 2016. PG&E files a GRC application every three years to apply to successive three-year rate periods, such as 2011-2013 and 2014-2016. The CPUC's rate case plan sets the requirements for the rate case processes of each of the state's major energy utilities.

PG&E's 2011 Quarterly Business Review #3 ("QBR3") provided the planning instructions and guidelines for the GRC. This information provided a starting point for developing the GRC forecast for 2014 through 2016. The QBR3 guidelines asked all units to "take a critical look at their expected activities and the cost of those activities," using the information to update the 2014 forecasts that had recently been completed through the QBR2 process.

The QBR3 forecast used the 2012 budgeted amounts that had been approved in October 2011 and the 2013 "preliminary targets" developed in the same process as foundations for developing the GRC forecasts. The instructions noted that, "Forecast amounts for 2014 should reflect each organization's best professional judgment and are not constrained based on previous forecast or target amounts." The guidelines anticipated that the first version of forecast submissions would be entered into PG&E's systems in December, and then undergo refinement and adjustment until April 2012. This timeline would allow GRC witnesses time to use final GRC forecasts to update their testimony and supporting work papers for a planned Notice of Intent (NOI) filing in July 2012 and a GRC application by December 2012.

Each organization received planning templates requiring the following information for use in the GRC forecast and filing:

- A multi-year financial outlook for expenses (2012-2014) and capital expenditures (2014-2016)
- Year-over-year "financial walks" (identifying sources of changes) from the 2011 original budget to the 2014 expense and 2016 capital forecasts
- Year-over-year financial walks by GRC exhibit and chapter
- Cost/benefit analysis for "new types of work"; a template and guidance were to be issued later in 2011
- A year-over-year headcount walk for corporate services organizations.

A cost benefit analysis requirement had arisen from the 2011 GRC Order. New types of GRC-proposed costs were to include in the revenue requirement estimated cost savings to be achieved or an explanation of why there would be no cost savings. LOBs received a project summary template addressing cost savings explanation. Project justifications included categories of "cost savings" and "cost avoidance." Another template section addressed non-cost benefits*, i.e.*, operational safety and reliability and environmental benefits a project would produce.

Responsibility to assure provision of the required analysis was left to management of each LOB, which received training, the templates discussed above, and a decision tree.

The next table shows the template for Electric Distribution capital. The other LOBs had to present a similar financial outlook for use in developing the GRC Forecast.

Electric Distribution GRC Template

(Amounts shown are pre-tax, millions of $)

	PROGRAM / MWC	HISTORICAL			2011		2012-2016						COMPARISONS						RATE CASE		
		2008 Actuals	2009 Actuals	2010 Actuals	2011 Budget	2011 YE Forecast	2012 Forecast/Request	2012 Prelim. Target	2013 Forecast/Request	2014 Forecast/Request	2015 Forecast/Request	2016 Forecast/Request	2012 Request vs 2011 Budget	2012 Request vs 2012 Prelim. Target	2013 Forecast vs 2012 Forecast	2014 Forecast vs 2013 Forecast	2015 Forecast vs 2014 Forecast	2016 Forecast vs 2015 Forecast	GRC	TO	GT&S
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N) = (H) - (F)	(O) = (H) - (I)	(P) = (J) - (H)	(Q) = (K) - (J)	(R) = (L) - (K)	(S) = (M) - (L)	(T)	(U)	(V)
1	Capacity & Reliability																				
2	6																		x		
3	46																		x		
4	8																		x		
5	49																		x		
6	56																		x		
7	Capacity & Reliability Total																				
8																					
9	Maintenance																				
10	7																		x		
11	57																		x		
12	2A																		x		
13	2B																		x		
14	2C																		x		
15	Maintenance Total																				
16																					
17	Automation & Protection																				
18	9																		x		
19	63																		x		
20	Automation & Protection Total																				
21																					
22	Emergency Response																				
23	17																		x		
24	95																		x		
25	Emergency Response Total																				
26																					
27	New Business & WRO																				
28	10																		x		
29	16																		x		
30	30																		x		
31	NB / WRO Total																				
32																					
33	Substation																				
34	48																		x		
35	54																		x		
36	58																		x		
37	59																		x		
38	Substation Total																				
39																					
40	Support																				
41	12 - Environmental																		x		
42	5 - Support																		x		
43	78 - Buildings																		x		
44	2F - IT Projects																		x		
45	Other MWCs																		x		
46	Support Total																				
47																					
48	**Total for Electric Distribution**																				

b. GRC Forecast Refinements

The first version of the GRC forecast came before the GRC steering committee in late January 2012. This committee includes the CEO, CFO, and all other senior PG&E officers. The first version of the GRC forecast presented an "opportunity for the LOBs" to propose what they considered to be required spending during the 2014-2016 rate period. This first version included total 2014 LOB expenses of about \$2.959 billion, or an increase of 25 percent from 2012 authorized levels. Electric Distribution expenses would increase by 11 percent and Energy Supply expenses by 27 percent from the 2012 levels. Proposed total capital expenditures for 2014 of \$4.055 billion would produce an increase of 72 percent from 2012 levels. Electric

Distribution capital expenditures would increase 32 percent and Energy Supply 104 percent. The increased capital and operating expense levels would result in an overall rate increase request of about $1.6 billion. After review with the GRC steering committee, the CEO requested that the GRC request be scaled back to result in smaller rate increases.

Subsequent versions of the GRC forecast (GRC updates) came before the GRC steering committee thereafter. The forecasts became "locked down" for all LOBs except Gas Distribution by March 29. The only changes made to the electric requests after the March 29 version involved moving IT projects from the IT LOB to the operating organizations. Gas distribution continued to update forecasts after March 29 until June. The final GRC request proposed a rate increase of $1.230 billion, or about 18 percent overall. During the GRC forecast revisions, Electric Distribution's requested expenses increased by an additional $17 million and capital expenditures an additional $44 million. Energy Supply's requested expenses decreased by $39 million and capital expenditures increased by $7 million.

The following GRC forecast information comes from the May 29 Update meeting. This information changed only slightly prior to the NOI filing, except for Gas Distribution.

May 29, 2012 GRC Forecast

LOB Expense ($ millions)	2013 Authorized	2014 Forecast	Increase from 2013 Authorized
Electric Distribution	$580	$631	9%
Gas Distribution	251	470	87%
Customer Care *	435	464	7%
Energy Supply **	626	723	15%
IT	215	262	22%
Shared Services	97	103	6%
Corporate Services ***	240	289	20%
LOB Expense Total	**$2,444**	**$2,942**	**20%**

Capital Expenditure ($ millions)	2013 Authorized	2014 Forecast	Increase from 2013 Authorized
Electric Distribution	$1,337	$1,716	28%
Gas Distribution	272	840	208%
Customer Care	112	189	69%
Energy Supply	317	636	101%
IT	119	212	78%
Shared Services	195	247	27%
Corporate Services	2	65	-
Capex Total	**$2,355**	**$3,906**	**66%**

The GRC included projects and spending from the Electric Operations "Improvement Plan" and the Energy Supply "Asset Management Public Safety Acceleration Plan." PG&E developed these plans following the June 2011 release of the CPUC's IRP report. During the GRC forecast refinements, PG&E focused on ensuring inclusion of safety investments from the Improvement Plan and the Energy Supply Plan. The Company announced a "Back to Basics" program in March 2012. This program included an increased emphasis on safety and safety investments. This program occurred too late to affect the GRC forecast. Nevertheless, PG&E maintains that the Improvement Plan and other turnaround efforts from 2011 were factored into the spending increase requests of these LOBs included in the GRC forecast.

c. GRC Forecast - Timing

The focused development of the GRC forecast kicked off with the QBR3 instructions and guidelines issued in mid-November 2011. A rough draft forecast that included the years 2014-2016 was first produced in December. This forecast was refined and presented to the GRC steering committee at least three times from January through the end of March 2012. The GRC forecast was "locked down" for the electric LOBs and the support LOBs as of March 29, 2012.

The chart below shows the timing for GRC Forecast development. The Electric Operations Improvement Plan and the Energy Supply asset management public safety acceleration plan would each have been completed in ample time to be included in the GRC forecast.

2014 GRC Forecast Development Timing

The building of the GRC forecast began in November and December 2011 and was completed and locked down for the electric and support functions at the end of March 2012. The CPUC Executive Director's letter addressing PG&E's use of risk assessments in identifying safety and security initiatives and spending for GRCs was dated March 5, 2012.

d. Conclusions

PG&E's 2014 GRC filing for electric and support services reflects the status of planning and safety and security programs as of the first quarter of 2012. The building of the 2014 GRC forecast began in November and December 2011 and was completed and locked down for the electric and support functions at the end of March 2012. Specific and focused development of the GRC forecast kicked off with instructions and guidelines issued to the LOBs in mid-November 2011. A rough draft forecast including the years 2014-2016 first came in December. Subsequent refinements, following input from the executive-level GRC steering committee, came from January through the end of March 2012. The GRC forecast was "locked down" for the electric LOBs and the support LOBs as of March 29, 2012.

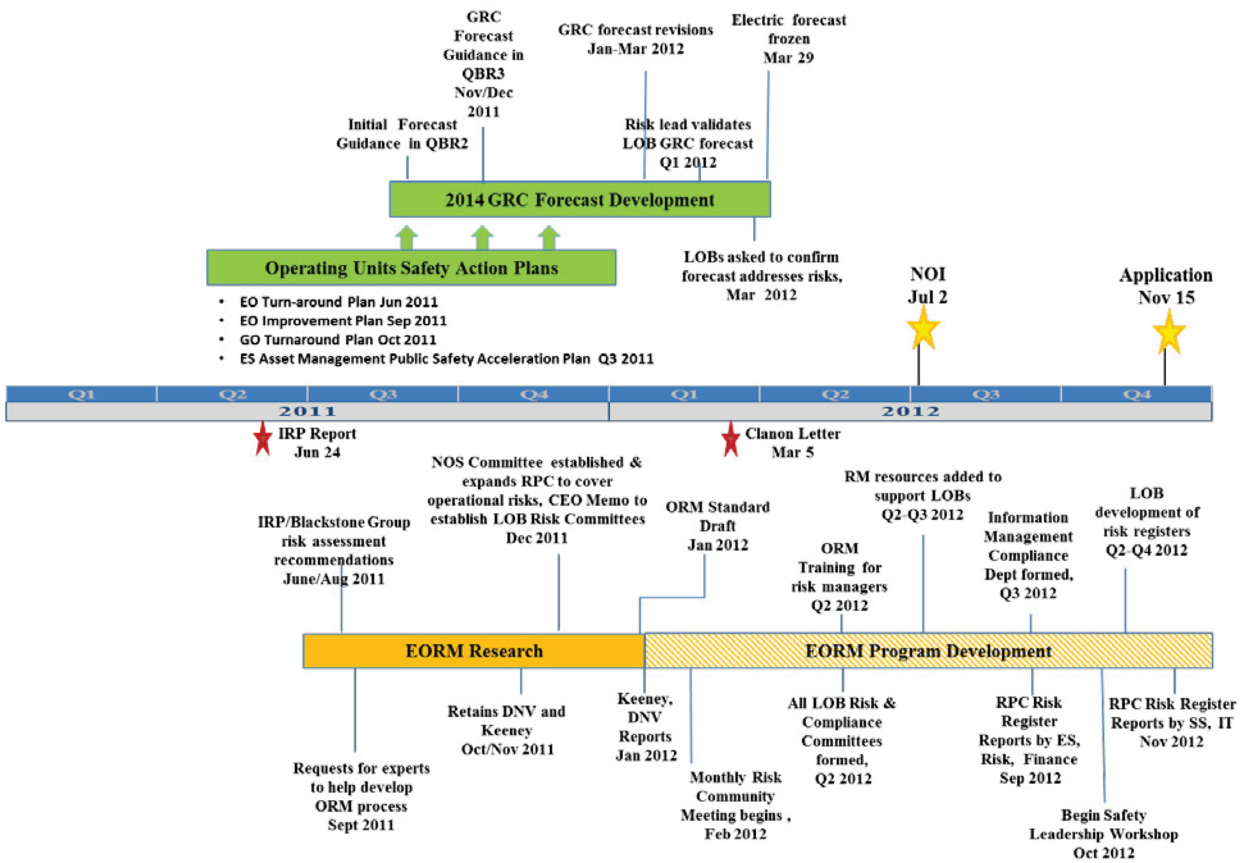
The previous chart shows the timing for GRC forecast development. The Electric Operations Improvement Plan, the Energy Supply asset management public safety acceleration plan and the GO Turnaround Plan, each of which has a safety focus, provided inputs to the GRC forecast. The March 5 letter came too near the end of GRC forecast development to permit it to be substantially considered on the NOI filing schedule.

The Company identified the specific actions it took in response to the March 5 letter in the immediate context of the GRC forecast. Those actions were limited to adding risk policy testimony and reviewing the existing forecast and testimony to ensure that it addressed operating risk management and identified risk gaps. As a result, the 2014 GRC does not include structured and quantified risk assessments as a basis for developing capital and operating expense requests. Risk assessment processes that drive work plans and safety and security spending were researched in 2011, developed in 2012 and are just being integrated on a test basis into the planning cycle taking place in 2013 (as discussed in the following section of this report).

PG&E developed its GRC forecast from November 2011 through the end of March 2012, as shown above. The development of the risk assessment of corporate processes began with research and "preliminary steps" following the IRP and Blacksmith Group reports in the summer of 2011. As of March 2012, PG&E had received operational risk management reports from consultants DNV and Dr. Keeney, formed Board, executive and LOB risk committees, and drafted an ORM standard. Training for risk managers in ORM and taking the first steps in risk assessment for the LOBs, such as identifying risks in a risk register, were to occur later in 2012. Risk assessment processes were early in their development processes in 2012. They had not advanced sufficiently to form a part of the planning processes, as acknowledged by Company executives. The risk and compliance session scheduled for early April 2013 will be the Company's first attempt at using risk as part of the integrated planning process.

The following chart compares the timing of the GRC process versus development of operating risk management at PG&E.

Development of GRC Forecast & Enterprise Operational Risk Management (EORM)



We also conclude that top-down spending limits did not constrain the development of the 2014 GRC capital and expense forecasts in general nor specifically those related to safety and security. The planning guidelines for this effort did not include any spending levels, limits or targets that might constrain the LOBs in the building of project and spending requests. When the results of the bottom-up forecast were reviewed by the CEO and the GRC Steering Committee, they asked for the total spending be scaled back somewhat, to lower rate increase percentages. On the second iteration of the forecast, the Electric Operations and Energy Supply "turnaround" plans were referenced, and the LOBs were asked to review any additional safety spending, to remove any unnecessary costs and to find operating efficiencies to a greater degree.

Total spending for electric capital expenditures and operating expenses showed little total change from the first GRC forecast iteration in January 2012 to the forecast included in the GRC request. During the GRC forecast revisions, Electric Distribution's requested expenses increased by an additional $17 million and capital expenditures by an additional $44 million. Energy

Supply's requested expenses decreased by $39 million and capital expenditures increased by $7 million. A portion of the revisions were due to reassigning IT capital and expenses from the IT LOB to the other LOBs.

The 2011 Electric Operations "Improvement Plan" and the Energy Supply "Asset Management Public Safety Acceleration Plan" focused on safety drove incremental GRC electric capital expenditures and expenses for 2014-2016. The GRC included safety and security projects and spending initially proposed in the Electric Operations and the Energy Supply "turnaround plans" that were developed following the release of the CPUC's IRP report in June 2011.

Liberty did not observe a substantial level of quantification of cost for safety and security related projects and programs initiatives proposed in the GRC. For the most part, cost savings for these initiatives were not quantified. PG&E instead focused primarily on narrative justifications of the projects; *e.g.*, defining reasons requiring the expenditures and addressing qualitatively the sort of consequences that could occur in their absence.

In Electric Operations, cost savings from project initiatives were quantified on a limited basis for a few of the major project categories. For instance, a major project category for infrared inspections totaled over $77 million of capital expenditures from 2014 to 2016, and about $13.5 million in annual operating expenses. PG&E quantified expenditures avoided from outages due to this significant investment in capital and expense dollars of about $1 million per year in operating expenses and about $1 million per year in capital. Another major investment in underground switch replacement of over $75 million from 2014 to 2016 included estimates of $200,000 per year in cost avoidance due to failed underground oil switches. The distribution network's SCADA safety monitoring new program included investment of approximately $38.5 million over a five-year period from 2012 to 2016. Estimates were made of about $3.5 million per year of reduced transformer maintenance costs and smaller amounts of other avoided costs due to the investment. This investment had significant quantified cost savings that could justify it on a cost/benefit basis. Overall, these examples from electric distribution show limited cost savings estimates on these major investments. For other areas such as large capital or investments in support services (such as the Alternative Emergency Operations Center for about $20 million), we did not observe cost savings calculations in the project justifications.

Liberty recognizes the cost savings benefits are difficult to quantify for many types of utility investments. Quantified cost savings for most utility investments that are not "discretionary" are very difficult, and often are not significant or comparable to the investment costs as performed in a traditional cost/ benefit or economic analysis. We recognize this limitation in performing such analysis. However, the quantification of as much cost savings or other benefits as possible is useful to utilities as information that may be used in the prioritization of projects. The more information that is provided regarding realistic and quantifiable cost savings or benefits, the higher relative priority that an investment should have due to its demonstrable benefits. While such cost-saving information is only a portion of the total picture in justifying projects, more information is useful in prioritizing the projects both within an LOB and between business units.

3. PG&E Operating Planning – Future State

a. Integrated Operating Plan Adoption

The IRP report provided PG&E an impetus to change its planning systems and processes. The report was critical of PG&E's strategic planning and its budgeting processes. The Company came to understand that its quarterly business review processes used to manage planning were overly finance-oriented, and based on inflexible templates. The overall intent was to change the planning dynamic to become more operationally oriented, and to spring from specific strategies and goals through work plans.

Company executives visited DTE (Detroit Edison) in November 2011 to observe planning processes that DTE based upon a General Electric planning model. PG&E's new CEO (formerly CEO at DTE) believed that the benchmarking and strategy that drove planning there was effective, and resulted in good financial discipline. Company representatives also visited General Electric to discuss the GE planning processes. PG&E decided near the end of February 2012 to adopt an "integrated planning process" based on the GE model. PG&E first used this new process in March 2012 to build plans for a 2013-2015 planning horizon. The effort to develop the new integrated planning process came shortly after construction of the 2014 GRC forecast.

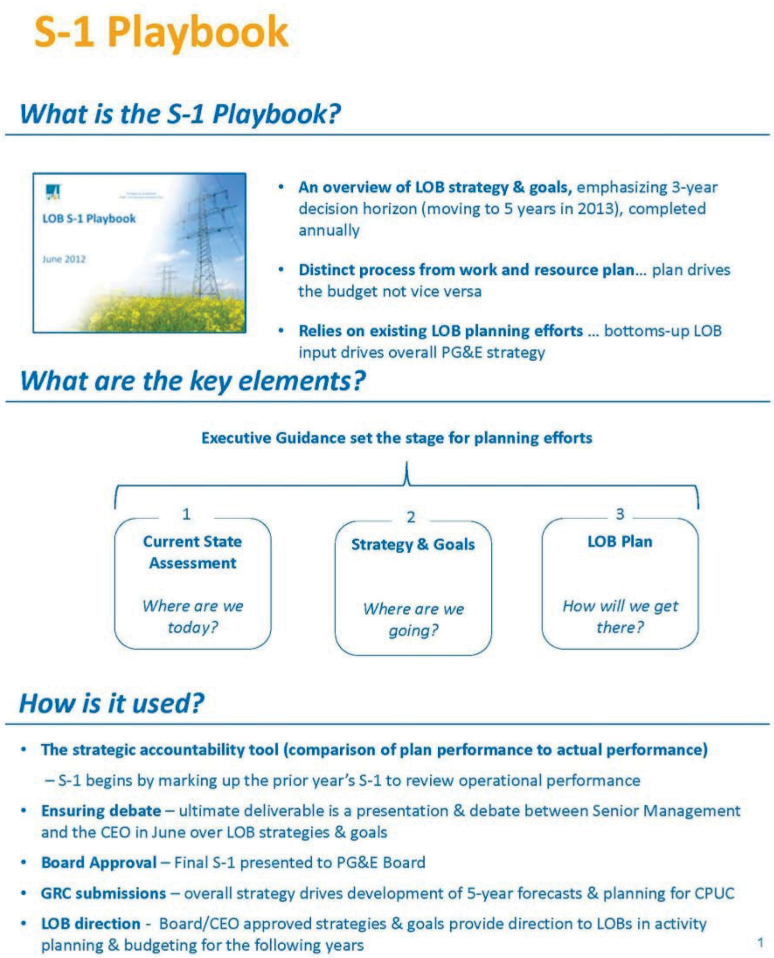
PG&E's introductory presentations and materials for the new integrated planning process described it as follows:

- CEO-led effort to implement a multi-year planning process modeled on GE best practices and utilized successfully at DTE
- Separated strategy from work and resource plan: rigorous strategic planning drives execution
- Bottoms up-planning and debate: incorporates input from officer direct reports and discussion between CEO and senior management in June regarding strategies and goals; September execution
- The ultimate deliverable is a single company plan for managing performance.

The Company highlights a number of differences between the new and previous planning process. One of the most important is to separate strategic from execution planning, and to allow strategy to drive the allocation of human and financial resources. Strategy and plan drive the budget, and not the reverse. Planning for strategy, work plan execution, and the allocation of resources previously had occurred concurrently, as part of the same process.

PG&E also sought under the new integrated planning approach to make the LOBs, rather than the finance team, the drivers of the process. Each LOB would develop its own bottom-up planning through a process engaging its officers and managers. LOB strategies and goals eventually approved by senior executive management and Board of Directors would provide direction to LOBs in activity planning and budgeting. The intent of the integrated planning process is to manage the Company to "one plan" with all other planning activities, including the GRC, integrated into this process.

The integrated planning process also extends the PG&E planning horizon from three to five years (starting in 2013), and makes GRC efforts a subset of the integrated planning. Budgeting takes a detailed one-year view that will also comprise a subset of the integrated plan. So-called "Session 1 (strategic playbook)" and "Session 2 (work and resource planning)" form key components of the integrated planning process. Session 1 consists of an overview of LOB strategies and goals emphasizing a five-year decision horizon. Each LOB assesses the external

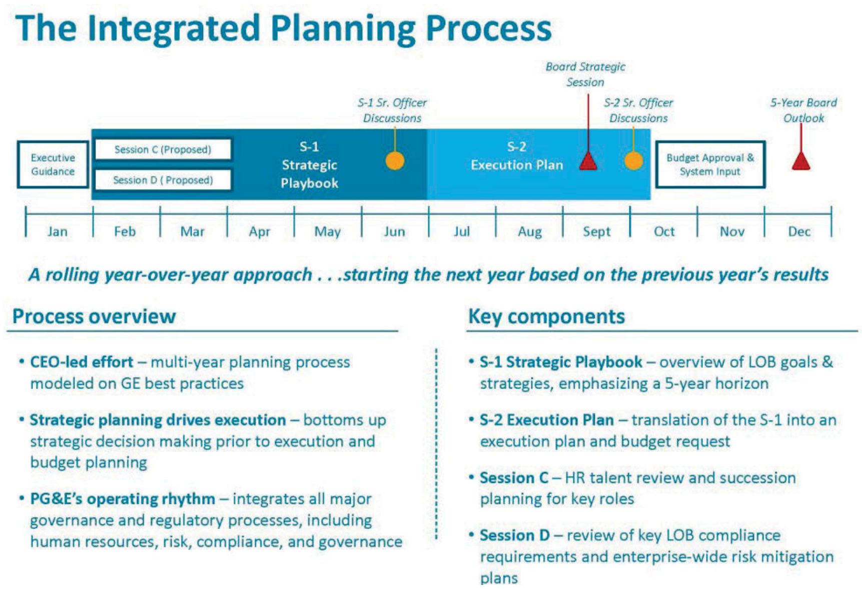


and internal factors that help or hinder its plan, examines current performance, and compares to unit benchmarks for top quartile performance. The business units then develop a strategy and goals for the next three to five years to address closing the gaps in their benchmark performance. An LOB strategic plan is then developed to reach each LOB goal, close the gaps in benchmarked performance, and determine the key metrics and milestones that will be tracked to measure performance.

Annually issued executive guidance kicks off the development of S-1 strategic playbooks. For 2012, targets for public and employee safety were provided for new electric metrics such as incidence of wires down, 911 emergency response, lost workday case rate, preventable motor vehicle incidents rate, and a SAIDI reliability target. Quartile performance targets for the year-end were also provided.

A key input to the development of S-1 strategic plans was originally termed "Session D," which addressed development and assessment of LOB compliance requirements and governance factors that influence strategy. PG&E's plans for "Session D" have evolved to include (beginning with planning work in 2013) risk assessments and mitigation as drivers of input to S-1 strategies for each LOB. Formalized risk assessment processes were being developed, structured and rolled out at PG&E during 2012, as we will discuss later.

The next chart graphically describes the annual integrated planning process and how the process should flow when fully developed. Note that initiation of the integrated planning process in March 2012 means that the Sessions C and D inputs were not in place to inform development of the S-1 and S-2 execution plan during 2012.

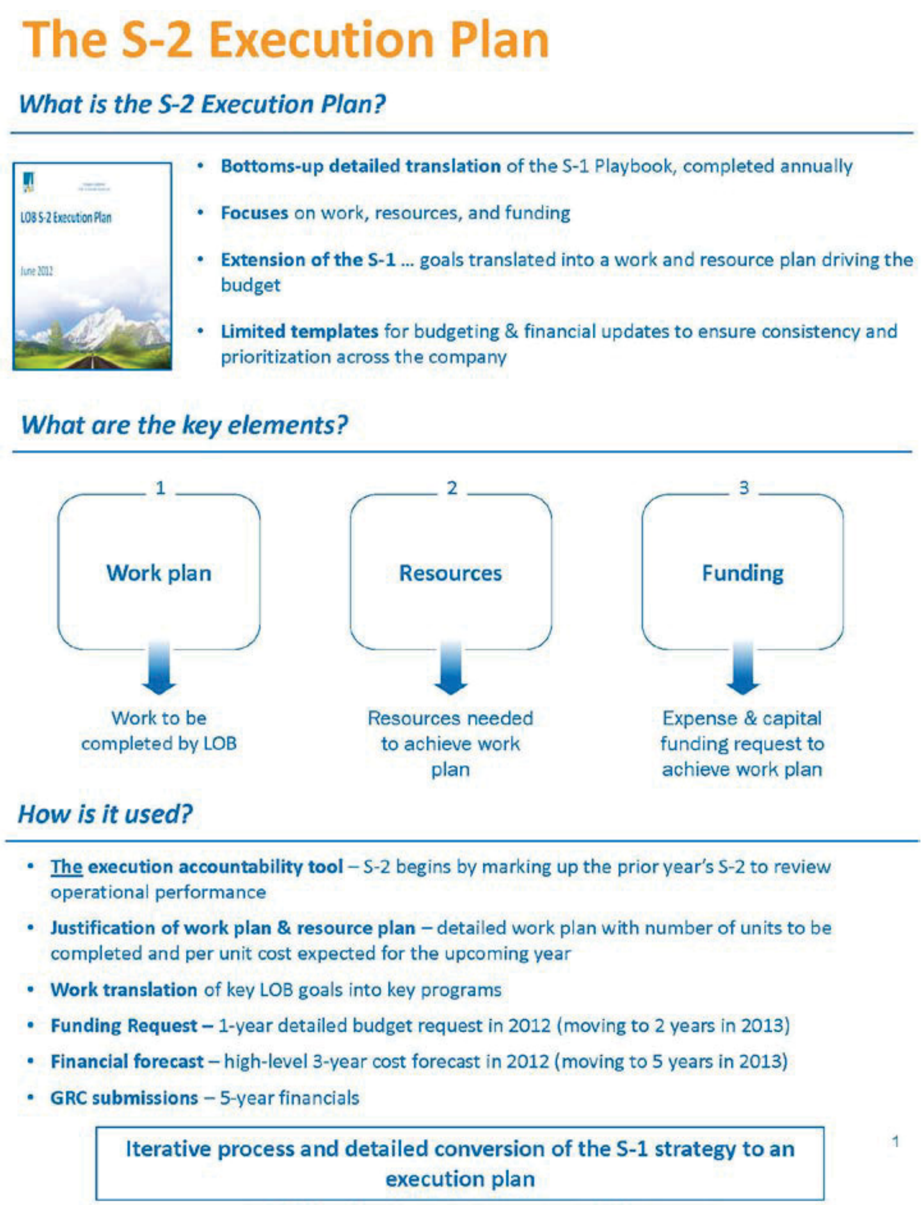


The S-1 strategic playbooks for each LOB are developed and presented to senior officers for discussion in June of each planning year, as shown above. The PG&E 2013 strategic playbook (corporate) was then presented to the Board of Directors in September 2012.

The S-2 process is a second primary component in developing the integrated plan that follows the S-1 process and utilizes its results as a starting point. The S-2 is termed an "execution plan." This plan translates the strategy and goals developed in the S-1 to key programs, focus areas and resources required. The LOB programs and focus areas are internally assessed to first determine work plans with key programs, expected performance versus the previous year and against benchmarks, and expected benefits over the planning horizon. The LOB work plan is to address the mitigation of potential risks or capitalize on opportunities identified in the S-1.

Each LOB also determines the funding required to support its work plan and resources. Drivers for significant year-over-year changes in funding required are to be identified. The key risks associated with deferring or eliminating work are also to be assessed. Methods for prioritizing work projects and programs used to determine a funding level request should be clearly defined and utilized. The LOBs are also required to compare the capital and operating expense requests in the planning process (in this case for 2013 through 2015) with the 2014 GRC forecasts for the same years, to confirm their alignment.

Unit work counts and unit cost targets are determined that result in a detailed work plan and the accompanying financial resource needs, including capital and expense estimates. Spending is then to be linked to operational gains and improvements prior to the development of specific capital and expense requests for each LOB. The Company's description of the S-2 execution plan is shown below.



LOB S-2 plans will undergo development in the July through September timeframe. The LOBs will then present them to senior executive management in early October, with budget approval anticipated by the end of November each year. Board of Directors presentations and approvals are scheduled for December Board meetings. A (highly confidential) five-year "Financial Outlook" covering the years 2012 or 2016 was also prepared and presented to the Board of Directors in December 2012. The financial outlook summarizes PG&Es financial performance and metrics through 2016, based on the three-year integrated plan for that year and views varying assumptions such as authorized and earn rates of return, timing of the resolution of the GRC and levels of incremental capital and expense spending. A five-year financial outlook of this type is common in the industry as a high-level financial overview and summary for the Board of Directors.

b. 2013 Integrated Planning Process

The integrated planning process is evolving in early 2013. What was formerly termed "Session D" is now termed the "Risk and Compliance Session." The LOBs completed in mid-March drafts of risk assessments intended to undergo discussion including senior executive management at early April sessions. These just-developed risk assessments will feed development of S-1 strategies for each LOB through early June. This will be the first time that risk assessment and compliance action plans will feed and drive the S-1 and S-2 processes. The initial 2012 integrated planning process did not benefit from structured risk assessment input.

The risk assessments developed for use in the April sessions are not complete. For example, the Electric Operations document considers a fairly small subset (albeit what the LOB considers a set emblematic of its most significant risks), and uses a judgmental process for identifying likelihood and consequence. Senior leadership considers these sessions to be more a test of the session process than a comprehensive set of structured risk analyses. Experience gained in the coming sessions may bring significant change in their use and in the risk information underlying them. In any event, senior leadership anticipates certainly one and likely several subsequent yearly cycles to conclude before the process reaches a mature stage. The uncertainties affecting this maturation process include both: (a) how the sessions consider and end up driving plans, and

(b) the ability to move the LOBs to full acceptance, understanding, and use of a more structured, analytical, and comprehensive risk assessment process.

In any event, the long-term goal is to link risk management to strategy development and resource prioritization through these processes on a formalized and structured basis. The 2013 cycle will be the first integrated planning process in which this process will be tested. PG&E recognizes that the 2013 integrated planning process is the "first time through" the entire process and that more developed risk assessments with more refined risk quantification will occur in future years.

In January 2013, the PG&E CEO issued his 2014 executive guidance to kick off the integrated planning process. The guidance included goals addressing regulatory commitments, customers, employees and investors. The executive guidance set forth:

- A safety performance goal of first quartile in the industry by 2014 and top decile safety performance by 2016
- First quartile operational performance by 2015 and top decile operational performance by 2017
- A goal to "ensure that the capabilities exist to continually monitor key operational risks and comply with regulatory directives"
- A goal to engage with regulators to achieve positive outcomes in rate cases
- Customer goals including achieving second quartile JD Power customer satisfaction results by 2014, first quartile by 2015 and top decile by 2017
- Goals for customer affordability, alignment of overall rate increases consistent with the GRC, and keeping future rate increases at or below inflation
- High-level employee goals including generating top quartile engagement results in the 2014 Premier Survey
- Investor goals of earning the authorized ROE by 2014 (excluding gas transmission), preserving balance sheet strength, and maintaining corporate credit ratings.

c. Conclusions

Risk assessments employing robust quantification of probabilities, consequences, and mitigation opportunities will happen in 2014 at the earliest. Using such assessments to drive capital and

O&M planning and budgeting will not occur before that time. The LOBs will first document and present their individual Risk and Compliance processes and results to senior executives in early April 2013. The current process is the first of its kind at PG&E. How far this year's process will go in establishing a "baseline" that may be built upon in future years is an open question in the minds of senior executive management. Management hopes that next year's risk and compliance session will "use risk and compliance information to allocate resources" in its process overview, but there is not a strong level of optimism regarding attainment of this goal that early. The linking of quantified risk assessments to strategy development in the S-1 planning process and to resource prioritization in the S-2 planning process does, however, represent an ultimate goal and "end state" of the overall risk assessment structure, as viewed by senior executive management.

Company executives recognize that the risk and compliance sessions are a "work in progress," and that the current process will be a key test in measuring progress. Executives express uncertainty about when the risk assessment process will reach its steady, expected state. They point to the large amounts of data and the analytic rigor that must develop to permit risk assessment to take a comprehensive and significantly more quantified form. It is reasonable to conclude from what executive management believes and what we have seen that it will take at least three years to arrive at this point. In other words, while the 2014 risk assessments will be further refined, they will not be a finished product. It is fair to conclude that significant PG&E concern exists with respect to setting expectations too high regarding the "vision" to quantify risk and use it to allocate resources.

B. PG&E Risk Assessment Development

1. Risk Assessment Drivers

The IRP report concluded that PG&E should acquire and develop a staff of professionals with the skills necessary to do state-of-the-art practical analysis of risk management decisions that concern public health and safety, employee health and safety, environmental consequences, socioeconomic consequences, and financial and reputation implications for the Company.

PG&E began an effort in 2011 to research and develop risk assessments for use in planning and resource allocation. This process did not produce major, evident changes in the use of such assessments in the current GRC filing. Nor has the Company completed since that filing any structured analysis of risk in relation to its GRC proposals. The subject of risk clearly received substantially increased discussion in the GRC. Moreover, the Company has continued to advance its consideration of risk, but has not made specific changes to the 2014 GRC forecast to incorporate the structure and the connection between risk assessment and proposed GRC expenditures.

The Executive Director of the CPUC advised PG&E in the March 5, 2012 letter that:

> … "*PG&E should include as part of your upcoming Notice of Intent to file a GRC the risk assessment that underlies your rate requests."… and "PG&E should provide testimony to identify and prioritize areas of risk and include the underlying rationale for your assessments."*

Our engagement, foreseen by the March 5, 2012 letter from the Executive Director, addressed this expectation, setting as part of our scope an evaluation of:

> *the adequacy of PG&E's use of risk assessment(s) in determining the appropriateness of the level of capital investment funding and Operations and Maintenance (O&M) expenditures*

Our scope in performing this review included an evaluation of "whether the utility analysis includes a credible cost/benefit analysis as the basis for its recommended safety improvement options." We similarly found in response to our inquiries that the GRC filing did not provide substantial cost/benefit justification for the particular levels of expenditure that its GRC proposes for safety-related projects, programs, and initiatives. We understand that the Company is preparing additional information of this type, but it was not available for our review before completing this report.

2. Risk Assessment Research

PG&E established an enterprise risk management process in 2006, at a time and in a manner that comports with our experience. Its ERM program had elements common in major utility companies:

- The program identified 10 to 12 major or catastrophic risk items (generally these are not safety-related risks)
- A general examination of consequences and mitigation efforts identified
- Assignment of each major risk was to a corporate officer "responsible" for managing it
- Refreshment of the ERM assessments on a two-year cycle.

PG&E assigned two employees to manage the ERM program.

The IRP, along with a Blacksmith Group report commissioned by the Company, stimulated the development of more thorough and wide-ranging corporate risk assessment processes. It moved ERM well beyond the initial level typical of the industry. As relevant to our review, this new approach sought to make operational risks an integral part of ERM. It did so by seeking to embed the primary processes in operational risk identification and response in each LOB, operating under the direction of top LOB leadership, and carried out through dedicated resources. PG&E also strengthened its corporate level ERM resources through providing process-based encouragement, guidance, and support. This enhancement reflected a sound effort to move risk management from its traditional, ERM base, which focused predominantly on a fairly small set of top-level risks, among which financial and reputational risks tended to dominate over operational ones.

However, and this is important from the perspective of the March 5 letter and our scope, the research and development of a structured, Company-wide risk assessment program, as recommended by the two reports, was only beginning at this time. It would not keep pace with the development and filing of the current GRC.

In October and November 2011, PG&E retained the services of Det Norske Veritas ("DNV") to develop a framework for an enterprise and operational risk management program. The Company also hired Dr. Ralph Keeney to provide input to this framework. By the end of January 2012, both DNV and Dr. Keeney had provided reports on a "system safety risk framework." In December 2011, a PG&E board created a Nuclear, Operations, and Safety Committee and expanded the charter of the Risk Policy Committee (RPC) to cover operational risks. Shortly thereafter, the PG&E CEO, before the two consulting reports, instructed executive and senior vice presidents to form LOB risk and compliance committees and to hire risk managers to review all operations and processes and associated risks. The PG&E Chief Risk Officer took responsibility for developing corporate risk assessment processes and providing guidance and support to LOB efforts, from within his Risk and Audit organization. These actions represented the kick-off of PG&E's development of a corporate-wide, structured, operational risk analysis processes.

3. Risk Assessment Development

The development of risk assessment corporate processes continued throughout 2012, but their development lagged the schedule for NOI and GRC filings. The Risk and Audit organization drafted an Operational Risk Management Standard in early 2012. The PG&E RPC approved it in late March. The standard has set the following direction, which embeds the basic risk management structure:

Effective risk management includes five key elements:

1. Leadership – the overall approach to governance; effective risk management performance indicators; and accountabilities, responsibilities and authorities for risk management.

2. Risk identification and evaluation – the process for identifying and analyzing issues that could threaten strategic objectives, company goals, business processes, and/or company assets, determining the level of risk, and prioritizing risks.

3. Risk response – the process of developing an appropriate response strategy to address a risk.

4. Risk monitoring and review – independent verification of control effectiveness; and analyzing and learning lessons from events, near misses, changes, and trends.

5. Change management – plans to insure risk management activities are changed in a controlled manner.

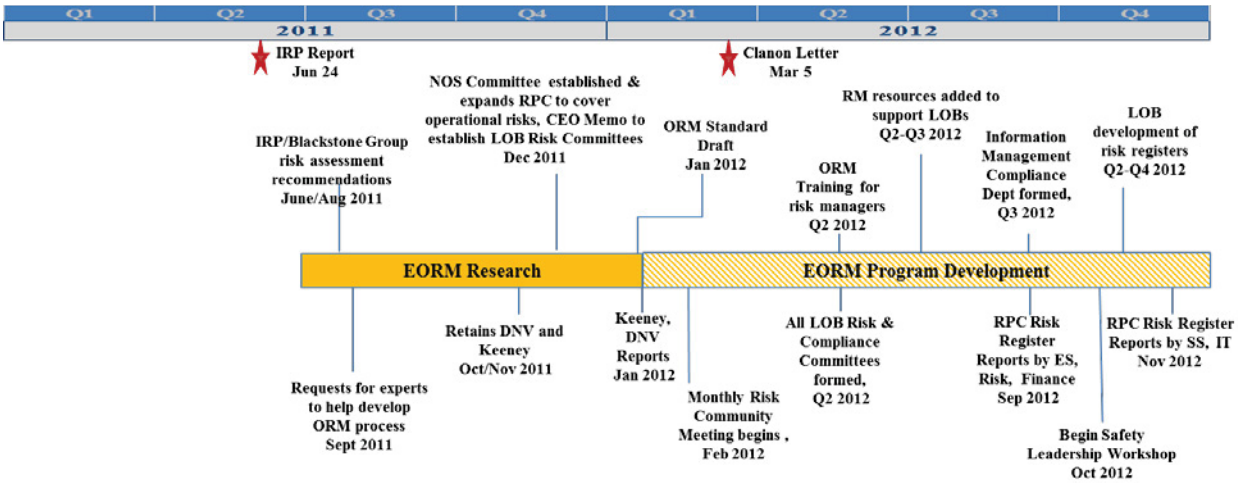
The ORM standard assigned to the Chief Risk Officer responsibility for developing corporate risk management standards, providing oversight of risk management activities, and reporting to the Board of Directors and its committees. The Chief Risk Officer also has responsibility for facilitating a risk management process that covers all LOBs, provides risk assessment and mitigation support to LOBs, and for managing the corporate RPC agenda to ensure adequate executive review. The executive vice presidents and senior vice presidents of each LOB have been given the responsibility and the obligation to perform the detailed work necessary for identifying and managing the risks within their organizations. They must define responsibilities and authorities for risk management, identify a risk manager and perform the structured risk-management activities that the corporate standard imposes. Separate LOB risk managers have responsibility for coordinating all risk management activities analysis and risk mitigation within their organizations and are expected to work with Risk and Audit to ensure corporate consistency of approach and conformance with the standard.

The Risk and Audit group developed criteria for evaluating risk and a generic risk assessment evaluation tool for use by the LOBs as a guide to assess and score risks. A risk register template was also developed to sort the risks and report them to the RPC. Guidance documents prepared for the LOBs included a "starter charter" for risk management, a risk register template, information flow graphs, risk identification criteria, a risk assessment and evaluation tool (spreadsheet), risk register templates, guidance regarding analysis of alternatives, and resources for assistance. The goal of the risk assessment team is to blend subject matter expertise in the LOBs with outside risk expertise hired by the Company through a teambuilding effort.

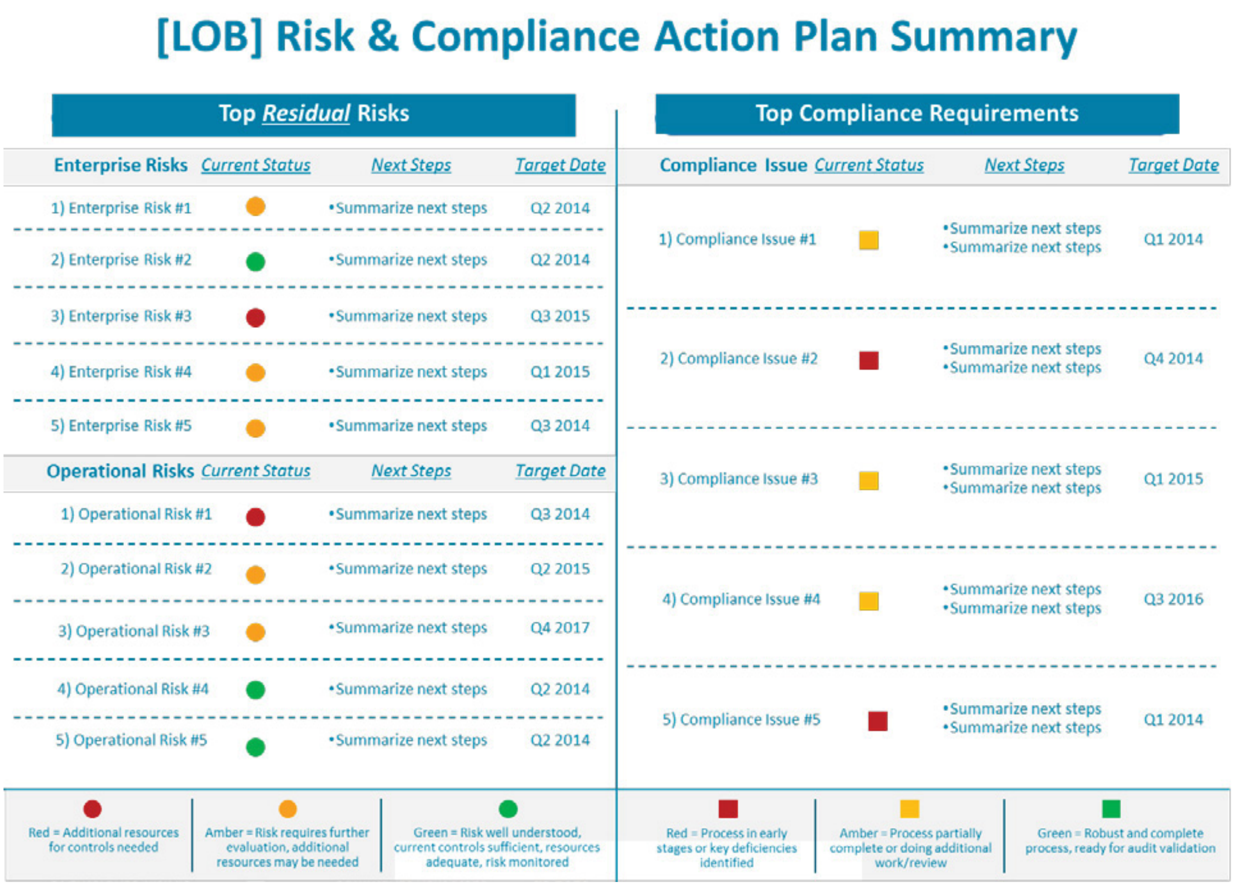
The Risk and Audit group has sought to stimulate LOB engagement in robust risk assessment and management processes. This year, the goal (which PG&E will test at the April 2013 planning sessions described earlier) will be to provide format and structure that can be used to identify, rank, and present alternatives for mitigating risks both within the LOBs and across them on a consistent basis, as part of the Integrated Planning Process. This process feeds the development of strategies, execution plans, forecasts and budgets, which PG&E intends in the future to drive GRC planning and preparation as well. The risk assessment structure is intended to be a medium to move toward a long-term vision of risk that will be attained over time, but is not expected to reach a steady state until after what senior leadership sees as a multi-year process.

A target date of the end of the first quarter of 2012 was set for hiring risk managers and holding initial LOB risk and compliance committee meetings. A two-day operational risk management training class for LOB risk managers was held in April 2012, with a half-day follow-up in May. A goal of identifying top operational risks for each LOB and presenting them to the RPC was targeted for June 30, 2012. This goal was not met, with some LOB risk identification occurring in the September through November timeframe. Electric Operations' identification process slipped to a later date. Company managers and executives have later recognized that the developing risk assessment processes in 2012 "did not take well," with the first step of the LOBs identifying their operational risks not being realized during the calendar year. The following chart shows the timing of research and development of the operating risk management program during 2011 and 2012.

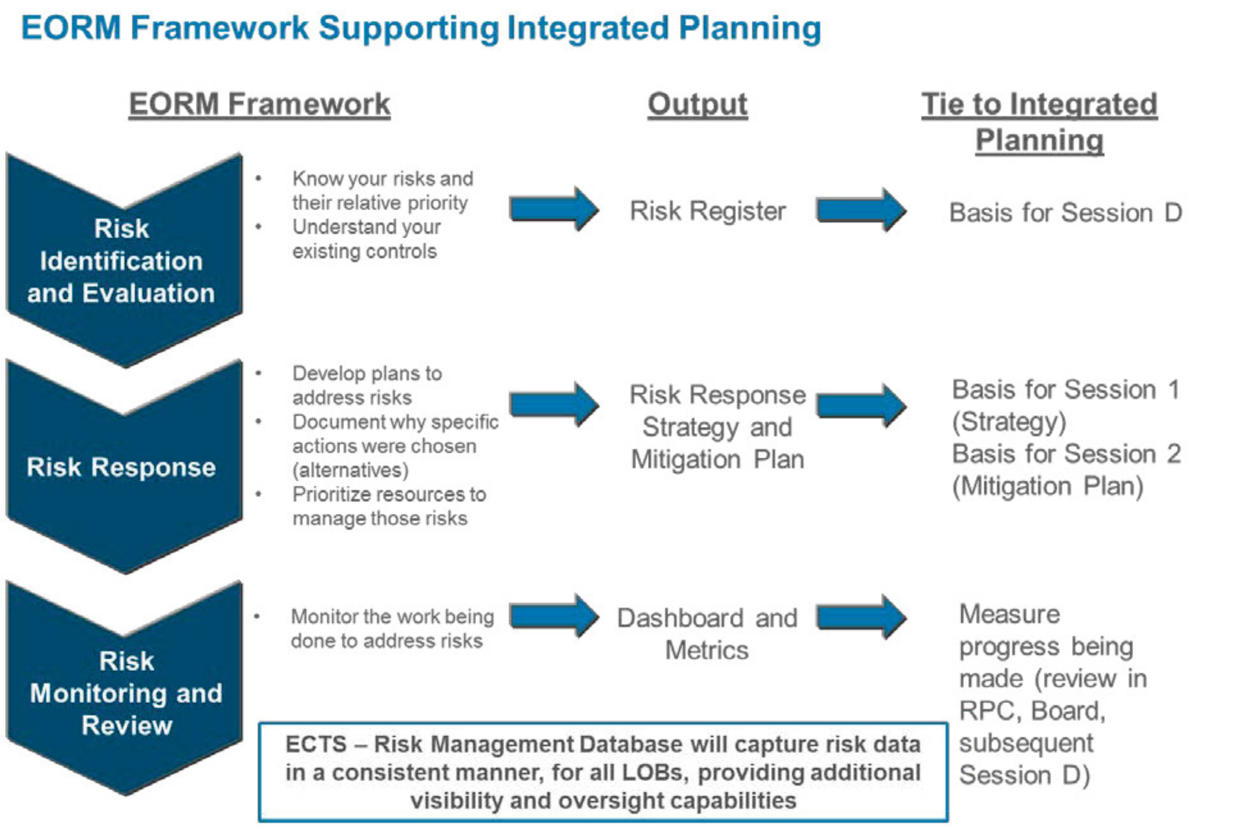
The Company then turned its focus to the Risk and Compliance (formerly called Session D) process scheduled to occur during the first quarter of 2013. The risk and compliance session is expected to identify and evaluate top LOB and enterprise risks and compliance issues that, if left unmitigated, could prevent the Company from achieving its strategic objectives. The output of this session is to inform the development of the S-1 strategy process for each LOB, and to drive the work and resource requirements of the S-2 process. The Company considers the early 2013 exercise within each LOB to be a preliminary and only partial test in the evolution of the risk assessment processes, which, if it develops as hoped will eventually drive the identification and assessment of risk mitigation measures, which will then flow into the corporate planning steps



that eventually produce projects, programs, and initiatives, which then will produce capital and O&M forecasts, which then will drive GRC filings. That result, we emphasize, is not what exists now, nor is likely to exist until the next GRC filing, if then. The next depiction provides an overview of the risk and compliance sessions.



This year's cycle is expected to establish a basis for learning how best to link risks and compliance requirements with strategic objectives and an action plan. The Company hopes that the 2014 planning process (for the horizon beginning with 2015) will allow the 2014 risk and compliance session to permit PG&E to "use risk and compliance information to allocate resources." The following chart shows the "end-state vision" that PG&E is planning to attain with regard to risk assessments that will be a driver of integrated planning and GRC forecast development.



4. Work Remaining to Reach a Mature State

PG&E has made substantial progress in developing corporate-wide risk assessment processes, but actual follow-through at the LOBs has lagged, as the next chapters of this report address. PG&E's integrated operating planning has introduced a new process that we consider to be leading-edge for the industry. Proceeding rigorously and aggressively with its development and implementation should drive better consideration of LOB safety and security goals, and make them usable as a primary driver of planning/budgeting and eventually GRC development.

PG&E's new integrated planning process represents a significant upgrade over its previous processes and would place the Company at the industry's leading edge. Liberty believes that that PG&E's new planning processes are innovative and well-designed to provide for better linkage of strategy and goals to resource allocation and execution. The new planning processes should be effective and industry-leading when fully implemented. The integrated planning process includes risk assessments as a primary input that is designed to drive annual strategy, goals and resource allocation in the future.

Starting in 2013, the annual integrated planning process will include the leading risk and compliance session that will drive the development of S-1 strategies for each LOB. This specific feature of the new integrated planning makes its design suitable for incorporating risk assessments and considerations into strategies that drive resource allocation and execution plans.

The 2012 integrated planning process did not include LOB risk assessment processes that fed into the S-1 and S-2 planning, because the risk processes had not yet been developed early in the year. In 2013, the Session D has evolved into the Risk and Compliance Session that is being developed by the LOBs in the first quarter. This will be the first risk assessment and compliance action plans that will feed into subsequent S-1 and S-2 processes. PG&E recognizes that the 2013 integrated planning process is the "first time through" the entire process and that more developed risk assessments with more refined risk assessments and quantification will occur in future years.

III. Power Generation

A. Background

Energy Supply has responsibility for internally-owned generating facilities and contracts for power. This LOB's major segments consist of Nuclear Generation, which operates the Diablo Canyon plant, Energy Procurement, which executes and administers generation contracts with third parties, and Power Generation, which operates all of the non-nuclear, PG&E-owned generation. The scope established for our study excludes Nuclear and Energy Procurement is not applicable. The analysis of Energy Supply therefore focuses on the hydro, fossil and solar facilities. From a public safety perspective, the primary focus will be on the hydro units and associated property, although consideration of fossil and solar facilities has been included.

B. Power Generation's Risk Program

1. Relationship to Corporate-Level Risk Management

Unlike other utility facilities, where the objective is to keep people safe by keeping them out, utilities are required to maintain recreational facilities in connection with hydro projects. As a result, there is a wealth of experience in dealing with public safety issues, including how to maintain effective communications with the public and how to design and implement effective emergency plans. The addition of a risk-based approach, however, does present a new approach and set of methods.

Guidance from the corporate risk group has been more mechanical and procedural than operational. A large number of guides, policies, procedures, templates, forms, and other instructional-type material has been shared with the LOBs, and support from risk experts has been available. This level of support can be bolstered in three areas. First, we have already discussed the need for a definition of philosophy. The corporate group can work with management and stakeholders to arrive at a suitable approach.

Second, oversight functions have been lagging and it would be helpful for the program if they could be accelerated. In this context, we mean oversight of LOB implementation of the program, assurance that risk considerations are applied in accordance with program expectations, assurance that appropriate risk scenarios are being examined, monitoring of preparation and implementation of risk response plans, and analysis and reporting on program status and effectiveness.

We recommend that corporate group accelerate its plans for providing effective oversight of LOB risk functions including risk considerations being applied in accordance with program expectations, appropriate risk scenarios are being examined, monitoring of preparation and implementation of risk response plans, and analysis and reporting on program status and effectiveness.

The defined governance provisions of the program are strong, but it is not clear that they are working as intended. It is difficult to see how the material formally emanating from Power Generation is sufficient to fully permit effective oversight by anyone. In addition, organizations like the RPC seem overextended such that there is limited time for safety issues. This seems to be confirmed by the published agendas. We recommend that ERM should evaluate the effectiveness of governance plans for the program versus the original intent and make recommendations to make the program more effective.

2. Power Generation's Risk Assessment Process

The tools and techniques of PG&E's program are noteworthy. In principle, they certainly rise to best practices. Some of the stronger program elements evidenced by Power Generation are:

- The existence of a structured approach to risk assessment with defined evaluation criteria and mechanics for scoring. Terms are well defined, scoring parameters are logically structured, and the instructions for rating various risks and consequences are consistent.
- An assessment tool based on the important principle of the product of likelihood and consequences is in place. Power Generation employs the RET, which measures likelihood and consequences. This brings an important tool to the table.
- The concept of inherent and residual risk is used. There are a number of benefits from using this technique, which is not as widely used elsewhere as some of Power Generation's other tools. This technique essentially provides a before and after scoring, which represents a clear measure of the degree and effectiveness of mitigation. Although

not used as such, it has potential for being especially valuable in cost-benefit analysis and in determining where one can get the most "bang for the buck."

- The level of effort devoted to assessments is generous. The way the program is structured, there is little opportunity for shortcuts or a less-than-detailed response. Power Generation has devoted the necessary resources and is making an effort consistent with a successful program.
- The conceptual approach to "alternative analysis" is good. The system provides the opportunity for a full ventilation of options and a good methodology for evaluation, although its implementation can be improved.

a. The RET and Operational Risk Priorities

The makings of a strong set of tools are already in place. Liberty believes that there is an opportunity for improvement in how Power Generation uses such tools. The RET, for example, contains the fundamentals critical to a risk program, but it is not clear that it is being used to its full potential. The tool is used by Energy Supply for the ranking of operational risks. Thus we can see in the Risk Register the operational risks identified by Energy Supply and the four which apply to Power Generation. Each risk is accompanied by its measure of risk from the RET tool, both on an inherent and residual basis. Residual risk is the measure after mitigation / controls are put in place.

It is not clear, however, what meaning those risk scores or rankings have going forward. They seem at this point not to be used again for any further purpose, including prioritization. One can ask whether their value was primarily in the construction of the Risk Register in the first place. The operational risks were filtered from a list of about 100 down to 21. It is understandable that the list of risks is regularly in a state of flux, both in terms of the nature of certain risks and the number of risks included. But we saw no evidence of this intent. Rather, it appears that the filtering process was more related to elimination of duplicates, combining risks, and eliminating choices perceived as weak. It does not appear that any RET or risk scores played a significant part in this process. The subsequent filtering down to nine exhibited some loose correlation to risk scores, but differed enough to show that other significant considerations were in play.

Our conclusion is that the risk rankings are not making the contribution one would expect, although, the process itself forces thinking and analysis that otherwise might not take place. That is a real benefit.

b. Risk Scores and Project/Task Priorities

The scores do not seem to be used to their full potential, but we do not necessarily see this as a major issue regarding the determination of operational risks. The real benefits of a ranking system come at the next level. Ranking and prioritization of a list of nine items is neither difficult nor useful. All nine are likely to be approved and scheduled to at least start in the near-term. Those nine may each spawn several projects or more, and each project will contain many tasks or sub-projects. The result can be hundreds of sub-projects or tasks, each contributing to mitigation of an important operational risk. The issue becomes how one determines from a risk and safety perspective what to do first when completing all the work might take years.

This question is important for PG&E. Hydro assets involve a large volume of risk-driven safety-related work. The large number of tasks that must of necessity be spread over several years makes the product of likelihood and consequences the most useful tool in selecting the work to be done first. A real value results in this environment where perhaps hundreds of tasks are planned to be done, as opposed to evaluation of a dozen operational risks.

This concept is not foreign to Power Generation and there is evidence of its use beyond the summary level operating risks. We did observe that the concept is in some use, but its effectiveness, uniformity of application, visibility to management, scope of use in the planning process, and application outside single projects is not clear. This appears to be a work in progress, and we recommend that the effort be formalized and plans for its future development and use laid out now. Power Generation and Energy Operations develop a consistent approach towards safety project/task prioritization using likelihood and consequences and applying priorities uniformly across all projects and tasks.

c. Relevance of Scores

We have expressed a positive view on the methods available to Power Generation, specifically the risk score calculation (likelihood times consequences) and its application on an inherent and residual basis. Such data offer the opportunity to describe risks and mitigation on a quantified basis. We have also expressed the view that such powerful tools deserve better use.

In evaluating the Power Generation data, the various risk scores seem to lack substantial meaning. Consider that many of the risk scores for the nine operational risks fall into a logical range (180–354). Two, however, have scores of 9 and 49, leaving one to wonder how they relate to the others. In addition, the degree of mitigation, as measured by the percent reduction in risk scores, ranges from 4 percent to 94 percent, again leaving one with questions. An example is whether a top operational risk mitigated by only 4 percent, is satisfactory.

We thus have concerns with the scoring system. A valid approach will produce logical results. On a scale of 1,000, a score of 800 should be roughly, perhaps very roughly, twice as important as a score of 400. A score of 80 should be considered not too far different from a score of 40, with both being of minimal stature. If such relationships do not exist, then the value of the system must be questioned. The choice by management of very low scoring risks is ample testimony to the lack of confidence in the scoring approach.

The theoretical contribution of a valid scoring system is too great to ignore. The further opportunities for use of the mitigation percentages are extremely enticing, perhaps even offering hope of meaningful quantification of safety risks. Accordingly, it is recommended that Power Generation work on refining the risk rankings such that they facilitate more effective analysis and comparisons of risk and degrees of mitigation.

We recommend that Power Generation refine the risk score methods in order to facilitate more effective analysis of risks and degrees of mitigation.

d. Alternatives Analysis

In seeking mitigation options, Power Generation uses "alternatives analysis." Mitigation options are presented with an assessment of feasibility, implementation barriers, schedule for implementation, cost of implementation, and the degree of risk reduction expected. This decision-making tool is good, but it is not clear it is used for that purpose. Rather, the context in which we saw alternatives analysis was in reporting decisions apparently already made.

The Operational Risk Management Standard provides the following guidance:

> *The Risk Manager explores the range of mitigation possibilities, including an alternatives trade-off analysis and calculation of the relative costs and benefits of different options and documents the rationale for the recommended mitigation activities.*

We did not, however, observe any such analysis or rationale. Providing management with a range of mitigating options is critical. If that feature is missing, it presents an issue with the effectiveness of the technique. We recommend that Power Generation adopt the required approach to alternatives analysis to inform management of a full range of options, and not simply the one or two preferred by staff. In addition, the dismissed options should be preserved in subsequent reporting.

The treatment of alternatives brings to mind certain language by the IRP:

> *We saw no evidence of any in-depth strategic discussions about the alternates, level of investment, trade-offs, or other factors that would relate to mitigating the risk.*

Liberty has made several similar observations regarding strategic discussions, alternates, and level of investment, suggesting that limited progress has been made on this particular IRP conclusion. The perception exists, at least on the part of the IRP and Liberty, that issues and options are perhaps not being fully ventilated, and this of course raises questions about how funding levels have been determined and validated.

3. Assessment Results

PG&E's top-level risks, of which there have been nine, are Board-level, or enterprise, risks. One of these is hydro risk, and it is assigned to Power Generation. At the LOB level, there were about 100 potential items initially identified in the Energy Supply. That number was reduced to nine, four of which fall under the direct management responsibility of Power Generation.

a. Hydro Risk

The risk of a dam or other structural failure was identified as an enterprise risk in 2007. It does not appear that much was done as a result until such risks moved up in priority after the San Bruno incident. After that, there were at least three significant step escalations in the program, as well as a continuing growth in momentum. After the San Bruno incident in late 2010, Power Generation performed new baseline inspections for all canals and penstocks. After the issuance of the IRP report, safety-related asset management programs were substantially accelerated and funding expanded. In late 2011, the program was expanded once again.

The definition of the enterprise hydro risk has stayed the same:

> *Failure of a dam or other hydro facility resulting in significant damage to third parties, the environment, and/or the Company.*

The degree of time and effort applied to this risk in recent years is considerable. In addition to the many inspections and facility assessments, detailed risk considerations were applied and weaknesses or gaps identified. The relatively simple list of gaps that remains is misleading, because the analysis and work to get to that list were extensive. In structuring the hydro risk, Power Generation concluded it was essential to look beyond large dams to other hydro facilities. Accordingly, the scope is listed in three categories: (a) dams, (b) conveyances, and (c) penstocks.

i. Dams

The possibility of a large dam failure must be considered paramount in any consideration of hydro risk. Power Generation has examined this risk from the perspective of three risk drivers: dam failure due to large flood, large earthquake, and normal operations. Before proceeding with a discussion of risk, it is first important to understand the processes by which dam safety are managed and assured. In this regard, PG&E is double-regulated for the most significant dams:

- 171 PG&E dams
- 81 of which are under DSOD jurisdiction
- 54 of which are also under FERC's five-year Part 12D safety inspection

The underlying processes are extensive and large dams do not lack for attention. Power Generation makes extensive use of consultants and outside panels to review its facilities and processes. Regulators have been active in meeting their oversight responsibilities. In addition, safety criteria and regulatory oversight tend to grow with time. This factor brings an element of continuous improvement in terms of managing and lowering risks.

There is no question as to the effectiveness of dam safety management in Power Generation. The processes in place are extensive, and have grown more rigorous and testing with time. For our analysis, however, we considered how, if at all, approaches and activities have changed with the advent of Power Generation's risk management initiatives. We found that the risk program has substantially elevated the priority of Power Generation safety programs, along with added funding and resources. Overall dam safety has increased as a result; it is strong and growing stronger.

Power Generation's analysis relating to dams identified seven "gaps" for which mitigation measures have been identified and are in progress of being implemented:

- Large dams – failure due to flood
- Large dams – failure due to earthquake
- Large dams – failure due to normal operations
- Small dams
- Aging infrastructure
- Records management
- Knowledge management

ii. <u>Conveyances</u>

PG&E's 368 miles of conveyances include canals, ditches, flumes, siphons and low head pipes, tunnels, and natural waterways. All high and medium public risk canals have been inspected for structural and geohazard conditions and most (27 of 33) low public risk canals have also been inspected. FERC regulates those conveyances that are associated with a FERC-regulated project.

iii. Penstocks

PG&E's 86 penstocks stretch over 48 miles. All have been inspected and inspection packages finalized for about half. The assessments address wall thickness, venting, geohazards, and adequacy of penstock protection.

b. Operational Risks

The four top operational risks falling under Power Generation comprise:

- Fuel cell risk: Power Generation is responsible for two fuel cell facilities located at local colleges. With hydrogen and natural gas present in a populated public area, the risk of leaks and/or explosion is important to consider.
- Failure of conveyance risk: There is obvious overlap here with the hydro enterprise risk.
- Public access to conveyance risk: Given that PG&E cannot have full control over access to its facilities, there is a risk that persons can access the facilities and that could lead to injury.
- Ammonia release risk: The delivery, storage, and use of anhydrous ammonia could lead to injury or environmental issues.

4. Infrastructure and Safety

Aging infrastructure is a growing issue in the electric industry. It is well accepted that investment has been constrained in the past for a number of reasons, including over-capacity, pressure on rates, and the preparation for deregulation. PG&E's hydro investment may also have been limited for a time due to financial condition and when it appeared that the hydro facilities would be divested. The industry now employs many facilities beyond their planned lives and high replacement costs make it difficult and unlikely that an aggressive catch-up effort can be supported. We term this the "infrastructure sustainability risk," which we define as the risk that infrastructure deteriorates due to age and other factors at a pace and to an extent that makes future recovery prohibitively expensive.

However, whether this forms an appropriate area of inquiry for this study, which is restricted to safety-related risks is a pertinent question. We think so for three reasons:

- Many components of the hydro system are at an advanced age. This feature has real ramifications in terms of equipment's wearing and in light of the fact that standards under which old facilities were built are often inferior to current standards.
- It is reasonable to think that today's infrastructure problems will contribute to tomorrow's safety problems.
- Age is not a significant factor in Power Generation's assessments, and this could lead to future age-related issues. The belief that age alone should not disqualify an otherwise healthy facility or piece of equipment is common in the industry, and when taken in a one-by-one analysis it is indeed valid. However, when taken collectively, such that the overall age of the collective system grows too fast, the danger grows that the volume of eventual replacement demands is too great.

We see the infrastructure sustainability issue more as a business risk than a safety one, but it is suitably important in both categories. In any event, PG&E might be well served in adding infrastructure sustainability to its important risks. In addition, we suggest that Power Generation place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.

We recommend that PG&E consider adding a new enterprise-level risk on aging infrastructure. We also recommend that PG&E place greater weight on age when evaluating risk and replacement decisions such that the system as a whole does not age too quickly.

We recognize that one of the hydro risk gaps (Gap 5) is aging infrastructure; therefore, our concerns are partially addressed in Power Generation's approach. There are two features, however, which would make a more focused approach preferable:

- The infrastructure approach we recommend would require a strategy founded on a vision for future infrastructure, as opposed to a focus on fixing problems. Power Generation's entire program would benefit from that shift in focus.
- If business risks were included, a different strategy than that selected for Gap 5 might have been chosen.

C. Risk Response Strategy

1. Risk Response Plans

The last output of the risk program is a Risk Response Plan (RRP), which lays out the mitigation scheme. The RRP has flexible requirements, but must at least present:

- Risk response actions
- Schedule
- Funding needs and other resource requirements
- Reporting and monitoring requirements.

A large amount of effort and analysis precedes the RRPs, but no tangible benefits or program results can emerge until after the RRP is approved, and there is a time delay after that approval. One can argue that it is only with the issuance of the RRP that "points are put on the board."

The IRP was critical of much of PG&E's enterprise risk management process, but was most critical of implementation.

> *Simply put, 'the rubber did not meet the road' when it came to PG&E's implementation of the recommendations of its enterprise risk management process.*

It was clear that the IRP found the promise of more "program improvements" or "ERM recommendations" to be unfulfilling in the continuing absence of a stronger implementation program. An aggressive approach to RRPs, aimed at demonstrating program effectiveness from the start and putting at least some points on the board early in the game, would seem to have been a logical strategy. To the contrary, however, Energy Supply set a goal of only one RRP in 2012, and that was not met. At the present time, the one RRP goal is April 2013, with the balance of operational risks due by the end of the third quarter 2013. We believe that a more aggressive approach to RRP completion would be beneficial.

We recommend that Power Generation adopt a more aggressive schedule to the preparation of RRPs. RRPs should be broken into smaller packages if the size of the package is too big to expeditiously complete.

2. GRC Links

We expect the RRP to become the needed vehicle for directly linking mitigation of specific safety and security threats to the proposals in the GRC. The challenge, however, becomes more straightforward if Power Generation's own RRP policies are expeditiously implemented. A process whereby each RRP is directly integrated into Power Generation's work planning and management systems, and directly feeds one or more lines in the GRC, seems a reasonable and powerful approach to fulfilling the March 5th letter's expectations.

It is not necessarily too late to address the current GRC. Many of the safety or security projects proposed for 2014 and beyond do indeed flow from risk assessments and subsequent mitigation planning. These are discussed further below under "Level of Funding." In response to Liberty questions, Power Generation has packaged some of these projects by their linkage to the hydro risk, conveyance improvements, and other categories. We will explain the limitations of the current data later, but the data is nevertheless helpful in understanding relative spending and the potential for future improvements in the direct linkage of risk assessment and resulting safety projects.

3. Hydro RRP

In addition to creating the major risk in Power Generation, hydro risk is also the forerunner for implementation plans. This process has been far from straightforward. Important components of this enterprise risk have emerged over time and been implemented. This includes, especially, the necessary field inspections and facility analyses necessary to frame the issues in the first place, as well as specific physical work that became apparent.

The lack of a final, complete, approved RRP for the hydro risk is therefore not surprising. This evolution, however, illustrates the need for a better approach. Hydro risk capital projects proposed so far in the 2014-16 window already exceed $100 million. One should question what PG&E's management requirements are for a project of this magnitude. We suggest that the levels of commitment here require at a minimum a well-thought-out project design, a rigorous scoping and approval process, a detailed budget and schedule, and a project management scheme to track the execution of the project from cradle to grave. To the extent such structure is not possible for whatever reason, the work can be divided into smaller packages, in order to assure the meeting of management objectives.

To call the presentation of the hydro risk confusing unfair, because there is a substantial amount of good work behind the projects. However, management and others charged with governance and oversight need a picture of the work that makes sense. In this regard, the inability to present a coherent story on the scope of the implementation work for the hydro risk, its eventual cost, its schedule, and what the hydro system looks like when it is done (*i.e.*, how the risk profile has changed), is a shortcoming at this point.

We recommend that Power Generation consider changing its approach to defining and structuring projects such that the work can be packaged in a manageable way, in order to give management a clear picture of the scope, cost, schedule, and intended results. Project managers will then have an important tool for managing work effectively.

4. Project Management

It took us some time to understand how the hydro risk project was being managed. We learned that a great deal was being done in virtually every aspect of project management; however, the visibility of the work beyond the implementing teams seems lacking. For example, we sought reports that would presumably have been required by executive management, or the RPC. The only document was a tabular listing of perhaps 130 detailed milestones planned for the project with an update of their current status. This listing may have some use to some managers, but it is not adequate to provide visibility for what is to be a more than $100 million project. There is no cost data, no overview of how the project is going, and no indication of deviations or items of interest to management.

On the other hand, many of the tools for effective project management seem to be in place at the working level. Detailed implementation plans, project work lists, budgets, detailed schedules, and action lists exist. There are weekly coordination meetings, a bi-weekly status review, a new system for tracking of open items, and internal cost reports.

We observed earlier (under "Power Generation's Risk Program") that oversight seemed to be a potential problem. With the reports currently available for upper management, this is likely to continue to be a concern. Recognizing that the hydro risk is the first and most important risk moving ahead with implementation plans, this need for more effective management reporting should be considered an important priority.

We recommend that Power Generation provide periodic reports that meet the standard of good project management, including credible analysis of cost, schedule, project issues, and other information needed for effective oversight.

D. Planning of Safety/Risk Projects

The process by which a company manages the identification, development, funding, approval, and subsequent implementation of projects is critical to the objectives of linking risks to tangible improvements. To the extent a robust system exists, it should not be difficult to overlay the requirement to track risk-driven safety projects from the cradle to grave. The PG&E system meets this criterion.

Power Generation employs a sound process for the planning of its work. Centered around the Project and Portfolio Management (PPM) module of SAP, the procedure provides for an orderly flow of new projects through three phases. Projects enter the system from many sources under the principle that "everybody is a planner." In the first phase, project classification, a triage process is employed to filter emergency work and other clarifying characteristics. Non-routine projects then move into a project definition phase while others move directly to Phase 3 for project evaluation and concurrence.

PPM is a highly mechanical system with an elaborate scoring process. Nevertheless, Power Generation notes that decision-making is far from mechanistic, with team reviews responsible for final project priorities and decisions. The detailed list of projects included in the GRC work papers are direct outputs from PPM. The tool is extensive and flexible such that it should easily be able to adapt to the new challenge of linking risks to projects and maintaining that identity throughout the life of a project.

The scoring system employs seven attributes as listed on the accompanying table. The final score is the product of these parameters. Multiplying so many numbers together can produce a huge range of values and Power Generation uses a normalizing divisor (10,000) to place the final score in a more manageable range. This does not change the fact that the eventual span of the final scores is nonetheless dramatic – orders of magnitude.

Attribute	Range of Values
Justification	20 for base 0 - 10 for other
Asset criticality	0 - 17
Vulnerability	0 - 10
Health	1 - 10
Prioity	0.2 - 10
Urgency	0.2 - 10
Other	1 - 10

A key observation here is that this score defines the priority of a project, but it is divorced from the prioritization schemes of the risk process. Although Power Generation emphasizes that "safety work always gets done," it is not clear by what mechanism this occurs, or even how safety is defined in this context. In addition, we have assumed that the safety tasks will number in the hundreds; hence it is a question of when and in what order safety works gets done, more so than if the work gets done.

We observed earlier that the RET risk score seemed to die at that point. It would seem appropriate that the risk rating stay with a project for life and that it somehow be factored into, or perhaps in some cases even dominate, the PPM score.

Liberty also believes that some adjustment in the scoring formula should be considered in order to provide more meaning to the scores and their relative positioning. It is difficult to understand the relative importance of projects with scores around 1,000 compared to many projects with scores less than 1. Intuitively one would expect that such relatively low scores would mean the projects would be dropped from consideration. However, that is not what the Power Generation process appears to do. We therefore have here the same issue faced in the RET scoring; *i.e.*, how to give meaning to the scores.

In this case, the solution may be easier than the RET challenge. For example, using a sum of the attributes, perhaps with weighting if desired, rather than a product will reduce the range to a reasonable number. If the product is deemed important, then a square or other root of the score will have the same effect of creating a manageable range and relationships. We recommend that Power Generation revise the PPM scoring method such that the resulting scores are over a manageable range and the relative values of the scores have some reasonable physical meaning.

In summary, PPM is sure to be the key tool in making a meaningful linkage between risk assessments and physical improvements. Projects can be fed from RRPs into PPM and managed cradle-to-grave. The modifications to the planning process and to the PPM tool to accommodate the risk/GRC linkage should be minimal and hence are recommended. We recommend that Power Generation modify PPM to facilitate the linkage of risks to projects.

E. Other Power Generation Safety and Security Initiatives

1. Public Safety

Public safety, although obviously important in utilities and other businesses, has not had the stature or level of attention of other programs, including employee safety. This was an observation of the IRP. PG&E's response has not been particularly aggressive, with a manager being appointed for public safety programs only in late 2012. Nevertheless, public safety is taking its appropriate place in the hierarchy of priorities. However, this is not new for Power Generation, where public safety issues have long been an important part of its programs. Power Generation facilities are in many cases open to the public, and include recreation areas specifically designed for the public. Other Power Generation facilities range over extended areas with many neighbors and physical limitations that limit Power Generation's control of access.

Power Generation presently has a Public Safety Officer and is adding two additional people to her staff. A new comprehensive public safety program has been created and is detailed in the GRC filing. Key features include:

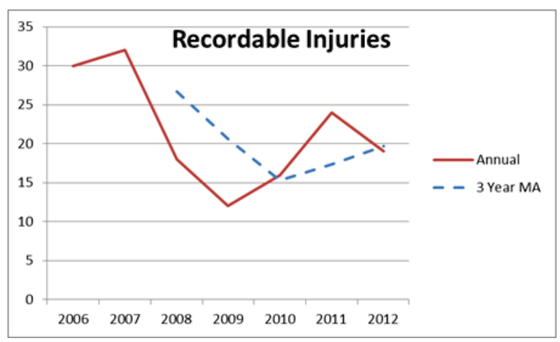
- Expanded efforts at public education
- Added warning and hazard signage
- Expanded initiatives in emergency preparedness
- Improvements to assure safer access to facilities and lands.

Large dollar initiatives do not necessarily flow from sophisticated analyses of risks. In some ways they are nevertheless as or more important than the major risk-driven physical improvements. We anticipate that their payback, (*e.g.*, in terms of public injuries or fatalities, is likely to be higher than the more massive investments. Accordingly, there needs to be a place in the risk/safety equation as well as visibility and priority for such initiatives. Given the low dollar requirements, there can be a tendency for such important work to get lost in the bigger picture.

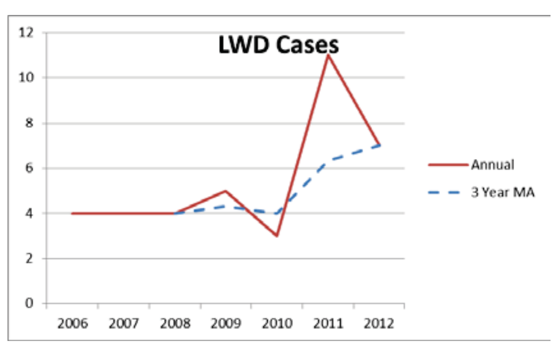
A major challenge in the public safety area of Power Generation is the lack of metrics. Public safety metrics and benchmarks are not in widespread use, and many of the hazards posed by Power Generation's facilities are unusual. Nevertheless, Power Generation sees this as an important challenge and is continuing to work on development of such metrics.

2. Employee Safety

From a Power Generation perspective, we have no reason to question management's commitment. Safety statistics, as they do throughout the Company, beg the question of just how much Power Generation has improved, and what is likely to evolve in the future as the Company continues its "safest utility" quest. We do note that this is a particularly aggressive goal given PG&E's recent performance.



Consider the trend in Power Generation recordable injuries, as shown on the adjacent chart. After a substantial improvement of nearly a factor of 3 between 2006 and 2009, the trend is again moving upwards in 2009 through 2012. This is highly unusual and, we suspect, well out of line with what one might expect. The data would have us believe that the heavy emphasis on safety in the last few years had no effect.



The results in terms of serious incidents add even more questions, because the pattern has been quite different. Consider the trend in lost work day incidents, which was level during the years that less serious incidents declined by nearly a factor of three. Results have deteriorated significantly. We caution that in the case of serious incidents, we are dealing with small numbers. Year-to-year fluctuations can therefore be suspect. We think this data is representative, however, since it is generally consistent with the far more numerous statistics at the corporate level.

There is some concern that PG&E's previously punitive approach to accidents may have artificially depressed the recordable injury statistics, because of individuals being hesitant to report accidents. Of course serious incidents cannot be hidden; therefore, that could explain the opposite trends in the data. If this is true, Power Generation's actual performance in past years can only be judged by the LWD data. In addition, future improvement trends in less serious incidents will be difficult to discern because we will be measuring against a flawed base.

3. Security

There is a significant enterprise risk (terrorism) related to security, but that is managed under Corporate Security and Power Generation's role is limited. In addition, the local security risks in Power Generation are also supported by Corporate Security. Security as a utility issue has grown in importance in recent years. NERC requirements for Critical Infrastructure Protection (CIP) continue to grow. Cyber security is a major focus now, although it is excluded from the scope of our study. Power Generation's facilities are affected on a limited basis by CIP requirements. A small number of facilities are deemed critical and these qualify because of their switching or black start capabilities. Related projects are included in the GRC. At the present time, there are no significant security issues as they relate to Power Generation.

4. Emergency Management

The science of emergency planning and management has grown considerably in utilities over the last decade. There has been a wide range of interests, from storm restoration to business continuity. Accordingly, most utilities have added skills and capabilities in this area and are growing increasingly sophisticated. For Power Generation, emergency planning has long been a required component of dam safety. FERC requires emergency action plans (EAPs) for all high hazard dams. Power Generation is responsible for 54 of them. The term "high hazard" refers to the potential consequences of a failure, not the possibility.

Power Generation's emergency management approach is structured around the National Incident Management System (NIMS). This approach uses an Incident Command System (ICS) in establishing an emergency response organization. Power Generation people are trained and drilled in this approach and are well-versed in its requirements.

Power Generation's hydro approach relies heavily on local emergency management agencies (EMAs). Power Generation maintains close coordination with these responders, including monthly communications, periodic open house, annual orientations, and periodic drills. A "typical" emergency would be managed by a Power Generation incident commander and the EMAs. Escalated emergencies, which are less likely because of the regional nature of the facilities, could be managed by the state emergency function and could also include escalation to Power Generation's corporate level emergency response plan.

Power Generation has extensive experience and capabilities in emergency management and no issues are apparent.

F. Level of Funding

From a GRC perspective, all of our discussions funnel eventually to the question of "how much." In our case, the question relates to safety and security proposals included in the filing. Our assignment is, in part, to determine the cost-effectiveness of GRC proposed safety and security projects, and there is a wealth of data on that topic, which will be addressed later under "Technical Evaluation." The more interesting question for stakeholders is how those various proposals add up to impact the ratepayer, so the questions of how that eventual level of spending for safety was determined and its appropriateness are paramount.

1. Drawing the Spending Line

The total planned Power Generation spending provided for in the GRC for 2014 is:

Capital

Approximate number of projects	725
2014 spending	$345 million

Expense

Approximate number of tasks	800
2014 spending	$191 million

Both the capital and expense spending levels are more than 30 percent higher than the corresponding 2012 levels. As we discuss below, it is not possible at present to define precisely which portion of the spending goes to safety and security projects because of the lack of a satisfactory definition. The data do show that a disproportionate share of the increase can be ascribed to projects categorized as safety under whatever definition is finally chosen.

The GRC includes volumes of details on individual projects. In fact, the Power Generation data as noted above has more than 1,500 line items and accompanying details. At the other end of the spectrum, the GRC includes general descriptions of the programs that drive the individual projects. So we have high level conceptual commitments on the one hand, and thousands of pages of supporting details on the other. Neither is particularly helpful or appropriate for the evaluation of the aggregate spending levels.

A major element of our study was to examine how PG&E links risk analysis and mitigation to the level of funding sought for safety and security in a GRC. If that initiative is to prove successful, all parts of the process must culminate in a credible end result. That bottom line result must be supported by a clear rationale, to permit stakeholders to fully understand it, regardless of their ultimate level of support for it. This is especially critical when the bottom line represents a major departure from past practices, as does the safety and security spending in this GRC.

Any linkage between risk and safety-related spending strikes us as irrelevant if one cannot understand the resulting rationale for the level of spending. An infinite number of projects can be conceived; most organizations do indeed generate a lengthy wish list. Management therefore needs the ability to "draw the line" at some appropriate level; *i.e.*, to determine what aggregate level of spending makes the most sense, and to decide which proposals to delete or defer.

Power Generation management, and their PG&E managers, did indeed go through such a process, and did draw the line; specifically at $345 million and $191 million for capital and expense respectively in 2014. Projects with a lower score than those aggregating to these totals were deferred to 2015 and beyond. Liberty was unable to determine how that process was conducted or, more importantly, what the rationale for the final choices was once the process was completed. The closest we were able to obtain to a rationale was the following, in response to the direct question of how the cutoff levels were established in the GRC:

> *The targets were proposed based on an assessment of the risks of rescheduling work to future years vs. the ability of Power Generation and its contractors to successfully execute the work. The forecasts presented in the GRC represent a ramp-up of expenditures over the 2014-16 period. This is the level of investment that PG&E believes is necessary to continue to provide safe, reliable, and affordable energy while meeting all federal, state, and local regulatory requirements, and public safety, recreation and environmental commitments.*

Such an explanation does not present a convincing rationale and justification for a spending level substantially beyond previous levels. It raises the question of how the regulator and other stakeholders can judge the appropriateness of the chosen spending plan. It begs the same question for management. We believe that management and the board of directors relied on a better explanation in approving the 2014 plans.

Our attempts to understand the aggregated spending level, encountered three major barriers:

- Lack of a suitable analysis, rational, and justification
- Lack of a workable definition of safety and security
- Lack of confidence in the 2014 work lists.

These impediments are discussed in more detail below.

a. Lack of a Suitable Analysis, Rational, and Justification

We questioned what should be required to justify increasing the investment in safety and security by a substantial amount, by a factor of 2 or 3 in some cases. We used the following check list:

- A compelling policy that drives the need
- A long term vision of what the future infrastructure looks like
- A long term plan to achieve that vision
- An analysis of associated rates to assure sustainability

- Defined near term projects that are justified in the context of the long term plan (and not just on their own merits)
- Analysis / justification of the bottom line
  - Why that number is optimum
  - The benefits that will result
  - The benefits or consequences of more or less spending.

With the exception of the first item, the policy definition, the other features are not present. We have alerted Power Generation to this gap, which we consider significant.

b. Producing a Workable Definition of Safety and Security

In seeking to parse the safety and security data in a workable format, we considered a number of definitions, none of which we found particularly satisfying or especially helpful. The chart below illustrates the wide disparity among four specific options.

Various Definitions of Safety and Security Projects

	All GRC Line Items	Safety and Security Line Items	ERM Hydro Risk Line Items	MWC 2L Safety and Regulatory	"Safety - Other" Line Items
Approximate number of capital projects	725	425	180	41	23
Forecast 2014 capital expenditures	344,644	133,337	126,363	49,614	18,893
Approximate number of expense tasks	800	150	65		17
Forecast 2014 expense	191,144	40,996	31,322		6,650

It is clear that we cannot have a rational discussion of the degree of safety and security efforts without a mutually agreeable definition. In the case of our four options above, the definitions are as follows:

- Safety and Security: This was a judgment by Power Generation after reviewing all of the GRC projects and deciding which had some relationship to, or impact on, safety.
- ERM Hydro Risk: Under this definition, only safety and security projects related directly to the hydro enterprise risk were considered.
- MWC 2L: The major work category of "Safety and Regulatory."

- Safety – Other: Liberty extracted the projects in PPM for which the justification was given as "Safety – Other."

We will use some of these definitions in our discussion but do not believe any are sufficient for the long-term. For the CPUC direction to be implemented effectively, and for a positive dialog on safety and security to be conducted, we need a better definition, one whose criteria might include:

- Facilitates linkage of spending to risks and mitigation
- Allows measurement of the commitment to safety and security and the trend of that commitment
- Provides a clear picture to stakeholders of where and why the money is needed.

With this in mind, we recommend that, for purposes of evaluating spending on mitigation of safety and security risks, only projects with the following attributes will be considered:

- The project is listed specifically in a Risk Response Plan associated with an enterprise, RPC-level, or operational risk
- The mitigation sought is for risks associated with (a) public safety, (b) employee safety, or (c) security matters that could jeopardize public or employee safety
- Where multiple mitigation objectives exist, the project qualifies only if it would have been done anyhow had safety or security been the only mitigation objective.

It sets a reasonable standard for the future and will allow a strong foundation from which the CPUC proposed program can grow.

As a high priority, we recommend that Power Generation provide an improved analysis and rationale for the proposed spending levels. Typical information that should be provided includes:

- A compelling policy that drives the need
- A long term vision of what the future infrastructure looks like
- A long term plan to achieve that vision
- An analysis of associated rates to assure sustainability
- Defined near term projects that are justified in the context of the long term plan (and not just on their own merits)

- Analysis / justification of the bottom line
  - Why that number is optimum
  - The benefits that will result
  - The benefits or consequences of more or less spending.

c. Lack of Confidence in the 2014 Work Lists

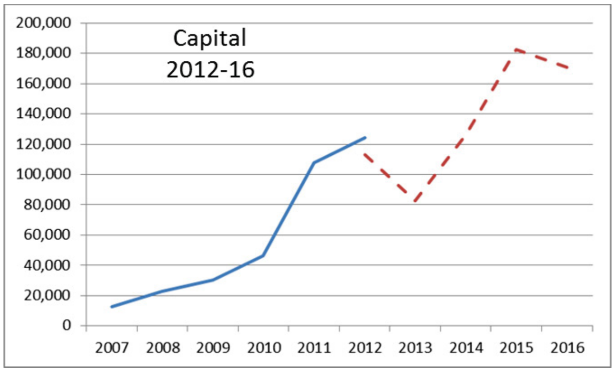
The planning and budgeting for any company, particularly in later years, carries a degree of uncertainty. The combination of the GRC process (which approves total spending levels, rather than specific projects) and Power Generation's internal workings makes it very unlikely that the projects that actually get done in 2014 will match the GRC list very closely. This is a problem, in that we really do not know what projects are being approved for 2014. We are left with a funding level whose rationale is not clear and a list of projects that is invalid. The uncertainty in the project list flows from several factors:

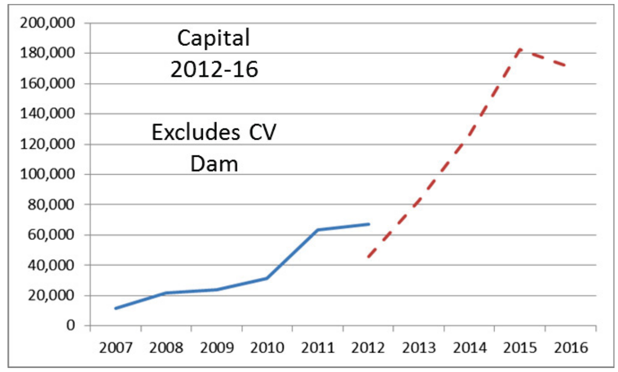
- It is predicated on the amount requested by Power Generation, which is not likely to be granted in full.
- It does not account for carryover work from prior years, which inevitable will displace some of the projects now proposed for 2014.
- It does not account for new work, which is sure to materialize before 2014, especially as the generation of RRPs picks up.

It would seem prudent to modify the planning process in the future to: (a) provide allowances for new and carryover work, and (b) provide the list of projects that are proposed to be deferred if less than requested funding is granted by the CPUC. Such an approach will go a long way towards creating a much-improved understanding of the work that can be accomplished. It will also provide a more realistic base from which to monitor performance against plans.

2. Spending Trends and Allocations

In analyzing trends, we used the most liberal definition of safety and security projects which, as a reminder, is Power Generation's judgment after reviewing all of the GRC projects and deciding which had some relationship to, or impact on, safety.

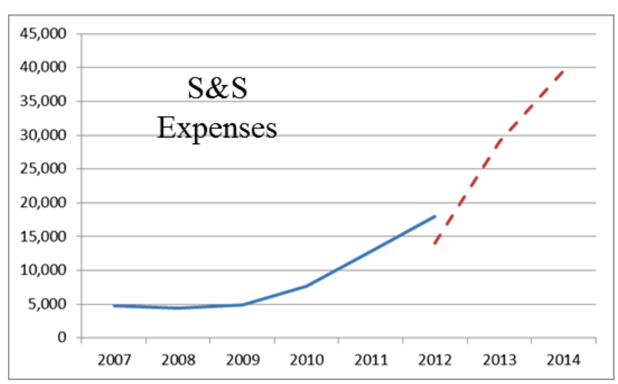




Power Generation has recently completed a major seismic upgrade project at the Crane Valley Dam and that significantly distorts the trend curves. Accordingly, we have presented curves with and without Crane Valley. Note that spending proposed for 2014 and after is sharply higher. In the case where CV is excluded, spending approximately triples. This is the basis for our earlier remark about safety spending increasing by a factor of two or three.

The major (>$5 million) 2014 projects are:

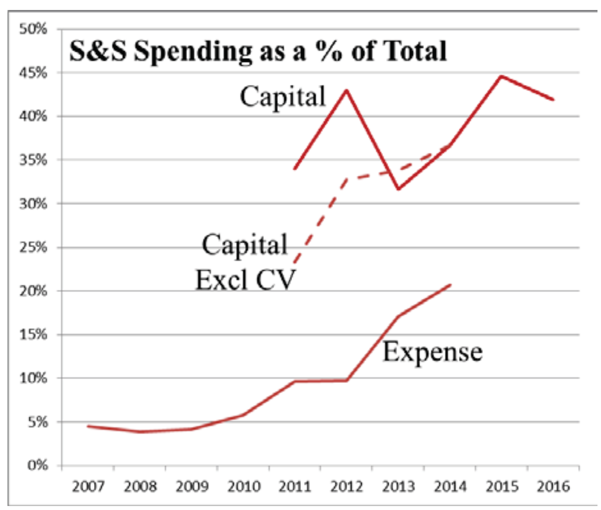
- Drum Canal/Gunite Work
- Bear River Canal Gunite
- Penstock Program (Asset Management)
- Fordyce Dam Leakage Reduction
- Wishon Dam Repl Slabs/Joints
- Dam Remediation (Asset Management)
- Potter Valley Repl Low Wood/Metal Penstock
- Dam Safety Instrumentation Automation (Asset Management)
- Water Conveyance (Asset Management)
- NERC-Required Security



The trend in expense work is also significant, although not to the extremes of capital. Nevertheless, the 120% increase in only two years (2012-24) is substantial by any measure. Note the relatively low amount of pre-San Bruno spending. The major (>$1 million) line items in the expense plan are:

- ERM activities
- Records management initiative
- Water conveyance assessments program
- Penstock program
- Dam safety instrumentation
- Dam repair program
- Facility safety programs
- Shasta required facility safety program
- Kerckhoff dam repair LL outlet valve #3
- Pit 5 OC low level outlet abandonment

It is useful to examine the portion of the capital and expense budgets devoted to safety and security over time. Safety and security is taking a sharply higher share of the budgets, although capital is somewhat constant if CV is included.



Although we obviously face analytical challenges as a result of definitional problems, the message of growth in safety and security is nonetheless very clear. In addition, we might expect to see a significant further escalation as the risk assessment process matures and more RRPs are issued, generating more projects. We are therefore unable to judge the appropriateness of that final level of spending, but we can indeed conclude that Power Generation is aggressively attacking safety issues in its infrastructure. Unfortunately, the magnitude of the increases makes the lack of better justification of the bottom line an even more serious omission.

G. Technical Evaluation

Our study included an evaluation of the proposed projects with the intent of commenting on their quality and cost effectiveness as justified by PG&E. The number of relevant GRC line items is about 575; therefore, a project-by-project analysis is not practicable. It is therefore more appropriate to conduct the technical analysis by testing attributes that characterize the overall process as well as other elements thought to influence the technical quality of Power Generation's work. These include:

- The quality of the engineering and decision-making processes
- The skills and capabilities of the people and organizations
- The effectiveness of oversight and management direction
- Analysis by major category, the nature of the projects, how they flow from risk assessments, and meet safety and security objectives, and trends in spending in these categories.

1. Project Processes

We have discussed the processes by which risks are assessed and projects defined. The risk process is very well advanced, although it is still fair to characterize it as a work in progress, particularly as applicable to the direct linkage of risks and projects. With respect to work planning, Power Generation has a strong system centered around PPM. And finally, the engineering analyses that have driven infrastructure examinations and improvement proposals, particularly in Asset Management, are impressive.

Accordingly, we would conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of engineering, risk, and decision-making processes, such measures are likely to be on balance cost-effective and of high quality.

2. Skills and Capabilities

While there are many Power Generation organizations upon which the success of these programs relies, the technical excellence question will be dominated by Dam Safety and Asset Management. The dam safety organization is led by a Chief and four direct reports, all of whom are experienced professional engineers. The group is expanding with a deputy and three additional engineers. The group is active and seems well-regarded in the industry. They are particularly active in benchmarking and lessons learned. Dam safety requires a significant use of consultants both for production work and oversight by consulting panels.

The Asset Management organization was formed in 2010 and has been the leading function in identifying Power Generation's infrastructure risks and developing programs in response. The level of production and the quality of the group's output in the last few years appears to be extraordinary. It is difficult to imagine what the state of the risk program would be today without the products of this organization.

The group consists of a manager, two lead engineers, three analysts, and 12 contract engineers. We have concern about the long-term presence of contractors. It would seem that after three years, the group should have started to wean itself from such a large consulting staff, and begin the transition to greater internal capabilities. The IRP noted PG&E's need to rebuild the core of technical expertise. Extended reliance on outsiders in what has become one of the most important and effective core business functions is not the way to "rebuild technical expertise." We have discussed this issue with Power Generation management and there seems to be a consensus that the transition to a primarily internal set of skills and capabilities is overdue. Management is likely already starting down this path.

In terms of supporting organizations, we were exposed to a broad cross section of Energy Supply personnel over a period of several months. Their level of participation in this process allowed us insights that would otherwise not be possible. During all of these interchanges, we never saw any reason to question the skills and capabilities of the Power Generation people and organizations.

In summary, we would conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of the technical and support organizations and the skills and capabilities of the people, such measures are likely to be on balance cost-effective and of high quality.

3. Management and Oversight

We begin by noting the high degree of regulatory oversight applied to the Power Generation organization. Such an environment as has existed for a long time establishes a strong sense of the need for compliance. With the number of people looking over Power Generation's shoulder, we are confident that suitable external oversight is present and reasonably effective. FERC oversight includes new risk-based decision-making initiatives including the potential for ALARP concepts, a five year mandated review of all high hazard dams, and FERC mandated emergency plans. At the state level, California, via DSOD, is thought to be the most thorough state in the regulation of dam safety. Finally, with the escalated oversight of the CPUC in safety projects, as will be recommended later in this report, the effectiveness of regulation is likely to increase even further.

Regarding internal management and oversight, we earlier expressed concerns about the risk program. Oversight efforts seem to be lagging, and the RPC seems overextended and tasked with too much. The apparent inadequacy of the quality of reporting to management is a consistent theme; it is difficult to fulfill one's oversight responsibility in the absence of information.

We saw no evidence that this issue should influence risk assessments and evaluations of projects. We conclude that, to the extent that the technical adequacy of Power Generation's proposed safety measures are a function of regulatory and management oversight, such measures are likely to be on balance cost-effective and of high quality.

4. Project Categories

In this analysis, we will again use the GRC subset defined by Power Generation as "safety and security" (S&S).

a. Type of Facility or Work - Capital

Growth in Annual Spending		
	2012	2014-16 Average
Hydro Dams	12,011	49,102
Canals	12,109	43,198
Penstocks	712	41,119
Flumes	3,597	11,310
Tunnels	1,019	4,087
	29,449	148,816

Dams, canals and penstocks represent the bulk of the proposed 2014 spending with 76 percent of the 2014 work. This grows to 82 percent by 2016. Major spending on flumes and tunnels does not occur until 2015, but then adds $42 million in 2015-16. These projects, which flow from a variety of sources including the ERM program, represent a massive escalation of effort from past spending levels. Consider the adjacent table which illustrates that average annual spending levels are increasing by a factor of 5 over 2012 spending. This aptly demonstrates the degree of "catch-up" spending that Power Generation feels is required for these facilities.

Safety and Security Capital Projects		
	2014 ($1,000)	% of Total
Hydro Dams	38,710	29.0%
Canals	38,545	28.9%
Penstocks	24,070	18.1%
Powerhouse equipment & facilities	5,979	4.5%
Security	5,100	3.8%
Other waterways	4,200	3.1%
Public Safety	4,125	3.1%
Arc Flash Mitigation	3,189	2.4%
Flumes	3,026	2.3%
Dam Gates	2,535	1.9%
Roads, Bridges, walkways	1,888	1.4%
Tunnels	762	0.6%
Ergonomic projects	683	0.5%
Electrical Safety	250	0.2%
Reservoir Log Booms	175	0.1%
Dam Low Level Outlet	50	0.0%
Fall Protection	50	0.0%
Total	133,337	100.0%

While all other categories are dwarfed compared to dams and the conveyances, many are still important and of interest, with the full list for 2014 shown in the accompanying table.

- There are multi-million dollar security initiatives in 2013-14 but very little otherwise.
- The public safety category increases significantly for 2014 and then doubles again to $8.8 million in 2016.
- Spending for arc flash mitigation continues at a level of several million dollars per year after spending of three times that much in 2012.

- Capital for electrical safety drops to token levels after multi-million dollar spending for many years. This seems to be more than offset by increased spending for facility safety that is charged to expense.

b. Project Initiation - Capital

The capital projects that comprise the GRC originate from six basic sources, with the bulk of the work falling into only three. These are broken down in the uppermost table on the below illustration.

The major category is dam and facility safety initiated projects, which are planned for $209 million over the five-year period. The second major category captures the projects initiated through the various Asset Management studies and programs. They amount to $200 million in the five year period.

All S&S Projects

Capital	2012-16 Total	% of S&S Funding
Dam Safety / Facility Safety Program Initiated Projects	208,553	31%
Asset Management Initiated Projects	199,759	30%
ERM Initiated Projects	173,162	26%
Related Specific Dam, Water Conv. and Pens. Projects	63,570	9%
Public Safety	20,227	3%
NERC Security	9,950	1%

ERM Initiated Projects

	2012	2013	2014	2015	2016	Total
Drum Canal/Gunite Work (Cap)	2,000	1,800	13,500	13,500	13,500	44,300
AM: Penstock Program CAP	0	50	8,000	18,000	38,000	64,050
Bear River Canal Gunite	3,996	3,000	5,000	5,000	6,000	22,996
Drum - South Canal Shotcrete	2,000	2,000	3,500	3,500	3,500	14,500
Drum - Wise Canal Shotcrete	2,000	500	3,500	3,500	3,500	13,000
Bear River Canal - Berm Stabilization	200	750	750	750	750	3,200
South Yuba Canal Gunite	500	500	500	500	500	2,500
Towle Canal Shotcrete	387	400	400	600	600	2,387
TigerCr Canal-Instl PillasterJointsLiner	310	681	323	330	0	1,644
Lime Saddle Patch U. Miocene Canal	0	0	250	0	250	500
Camp 2 Flume Replace Liner	150	550	0	0	0	700
Bear River Canal Repair	300	0	0	0	0	300
Phoenix Flume Sheet Liner	275	300	0	0	0	575
Coleman Gunite Canal	0	0	0	160	0	160
South Yuba Box Flume Replacement	0	0	0	450	1,900	2,350
Total	**12,118**	**10,531**	**35,723**	**46,290**	**68,500**	**173,162**

92%

The third category is of particular interest to us since it flows from ERM initiated projects. These items amount to 26 percent of all safety and security funding, or $173 million. Ideally, if the wishes of the CPUC can be achieved, virtually all major S&S expenditures should flow from the risk program. Of course with the narrower definition of safety and security we propose, the total list of projects is likely to be less as well.

The ERM projects are listed in the lower table above. The projects are sorted by 2014 spending. Note that the list is dominated by the top five projects which amount to 92 percent of the requested funding. Four of those top five projects are canal projects, as are most of the projects on the list. All of these projects are associated with only one of the seven gaps defined in the hydro implementation plan, and that is Gap 5 – aging infrastructure.

There are a number of important risk program messages embedded in this data. It illustrates that the direct physical work flowing from the risk program is limited at this point. This is not a surprise as we have already noted the limited progress of RRPs. Also, while the dollar volume of projects is considerable, the number of projects is limited – only five can be considered sizable efforts. Finally, the fraction of safety and security projects whose genesis lies in the risk program is small, and this is a function of a small numerator (limited ERM projects) and large denominator (inflated definition of safety and security projects).

The data starts to paint a picture of what future GRCs could look like, with a rigorous definition of safety and security initiatives and a strong linkage between those initiatives and the system risk assessment.

c. Project Justification

PPM includes a designation of the primary justification category for each project. It will be desirable to include eventually a field for linkage to an RRP and the designation as a safety or security project by whatever mutually agreeable definition is approved. In the meantime, the justification contained in PPM provides a good understanding of what has motivated most projects. The accompanying table shows that the vast majority of

Justification	Number of Projects	2012-16 Funding
Reliability	79	432,269
Safety - Mandated	6	126,305
Safety - Other	30	54,367
Regulatory Required - Mandated	6	13,501
Infrastructure	1	95

projects are justified on the basis of reliability. The definition used by Power Generation allows such reliability-driven projects to be categorized as safety-related if there appears to be a contribution to employee or public safety.

d. Type of Work - Expense

The largest expense category is facility safety, with a substantial proposed spending increase over current levels. Dam and conveyance work approaches half of the spending on safety and security and this is nearly all new money, having only token amounts in these accounts in 2012. The public safety line is also noteworthy. Again, funding was minimal in 2012 but has changed by factor of 10 in 2014.

Safety and Security Expense Items

	2014 ($1,000)	% of Total	Change 2012-14
Facility Safety Program	8,700	21.2%	2,493
Hydro Dams	7,616	18.6%	6,723
Dam Low Level Outlet	4,725	11.5%	4,286
Penstocks	3,665	8.9%	-177
Public Safety	3,594	8.8%	3,212
Documentation and Data Accessibility	2,612	6.4%	2,612
Training and Qualifications	2,554	6.2%	219
Other waterways	2,109	5.1%	681
Security	2,064	5.0%	2,064
Dam Gates	717	1.7%	708
Powerhouse equipment & facilities	674	1.6%	653
Fall Protection	640	1.6%	392
Ground Grids	548	1.3%	282
Roads, Bridges, walkways	398	1.0%	391
Arch Flash Mitigation	210	0.5%	95
Tunnels	90	0.2%	92
Miscellaneous Safety	80	0.2%	-87
Total	40,996	100.0%	24,640

Documentation and data accessibility, a fallout from the ERM hydro risk, represents a major new program in the multi-million dollar category.

Security costs, which were previously zero in the expense budget, now consume more than $2 million.

e. Non-Hydro Projects

We have not discussed in detail to the balance of the Power Generation fleet, which consists of three fossil units and a number of solar and fuel cell projects. This does not mean, of course, that these other units are ignored in the risk assessment process. To the contrary, two of the four operational risks discussed above are in non-hydro facilities (ammonia at a fossil plant and hydrogen and gas risks at the fuel cells). But the risk levels and appropriate spending levels for the non-hydro facilities are considerably less, probably by two orders of magnitude. Power Generation is applying a focus on these facilities that can be considered substantial and adequate.

f. Summary of Safety Projects

A key objective of this GRC was to create a new priority for safety and security. That objective has surely been met. We have seen that proposed spending in 2014 and beyond has expanded by more than 30 percent over 2012 levels, but that does not tell the story. When spending increases are confined to safety categories, the increases are greater, by a factor of 2 or 3 or more in some cases. The definition of safety and security, which overstates the number of projects classified as safety, at the same time causes an understatement of the magnitude of the percent increase.

Therefore, it is clear that Power Generation has elevated the consideration of safety, and seeks corresponding funding. There is an element of catch-up, particularly as applied to infrastructure. Spending in recent years has been relatively small and, prior to that, spending was constrained by first the financial condition of PG&E and then the belief that hydro facilities would be divested. Critics might characterize this as neglect of the facilities, but our experience suggests otherwise. These were real limitations for utilities caused by changing circumstances at individual utilities and the industry in general. Catch-up at this time is indeed an appropriate and prudent strategy.

Our evaluation concludes that: (a) the elevation of priorities in Power Generation has been appropriate and successful, (b) the nature of the projects is consistent with the needs of the system and the new priorities, (c) the technical development of projects is strong and they are suitably justified and of adequate quality, and (d) while linkage to risk assessments remains limited, a picture of how this can and should work in the future has emerged and the vision seems to be absolutely attainable. The one major question hanging over all of this is the aggregate level of spending, whose rationale and justification remain clouded.

IV. Electricity Distribution

A. Background

PG&E's Electric Operations LOB operates one of the largest single-company, single-state electric distribution system in the United States. The PG&E service area covers 70,000 square miles, and ranges from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada mountain range in the east. PG&E operates and maintains the following electric distribution facilities to serve approximately 5.1 million electric customer accounts:

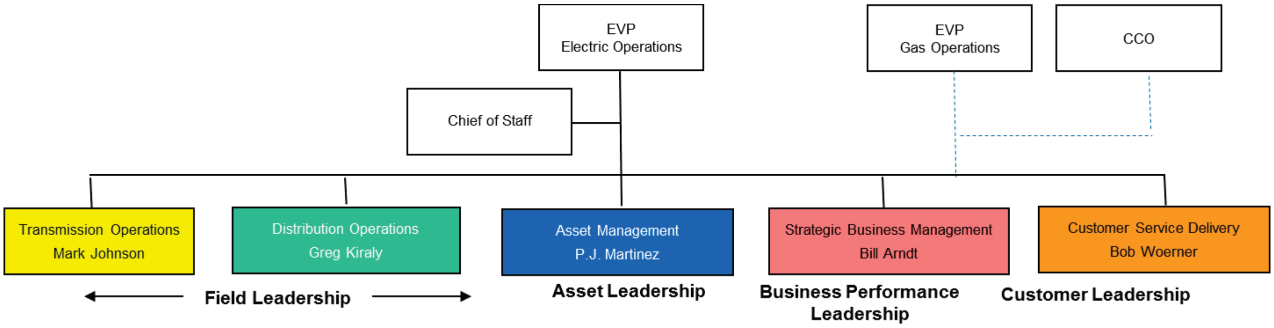
- 113,500 miles of overhead primary distribution circuit
- 2.4 million wood poles
- 27,000 miles of underground distribution circuit
- 8,000 underground manholes
- 3,200 feeders & 6,000 reclosers.

PG&E's diverse electric distribution system contains large numbers of rural and suburban underground residential distribution (URD) circuits, along with an extensive underground network system in San Francisco and Oakland.

B. Organization Changes

Following the September 9, 2010 San Bruno gas pipeline explosion, PG&E initiated a major focus on infrastructure and operations improvement. PG&E split the electric and gas organizations into two separate organizations in May 2011. Electric Operations also decided to reorganize. The organization structure prior to May 2011 used nine separate functional departments. Issues under this organization included gaps in matching planning effectively with operating needs, fragmented responsibilities producing diffusion in accountability and suboptimal spans of control, and inefficient work execution. PG&E implemented the new organizational structure shown below in January 2012. This structure's five departments streamline the LOB's operations.

Revised Electric Operations Organization



PG&E expected this reorganization to improve visibility and accountability for system safety, to enhance compliance focus and results, to improve work execution, and to increase efficiency. Some of the key design features of this reorganizational structure included:

- Distinct groups for transmission and distribution
- Strategic layers for asset strategy, compliance, and business management
- Centers of excellence for engineering, design, and project management
- Accountability by distinct work types to ensure ownership of results
- Central resource planning with selectively local scheduling
- Distinct customer group focused on meeting customer needs for both gas and electric businesses.

One of the new work units formed is Electric Distribution Asset Strategy and Reliability. It forms part of the Asset Management group. This unit exists to address strategic asset management plans for aging assets. This role represents a major element of plans to improve system safety by reducing equipment failures. PG&E does not have a formal asset management program in place. The Company is currently assessing the PAS 55 asset management system for implementation. PAS 55 provides an asset management process with systematic and coordinated activities and practices through which an organization can manage its assets optimally and sustainably, considering performance, risks, and expenditures over their life cycles.

We found that the revised Electric Operations organizational structure is better positioned to address aging infrastructure and system safety issues. A number of features of the new organization provide more focus on aging distribution infrastructure and system safety issues.

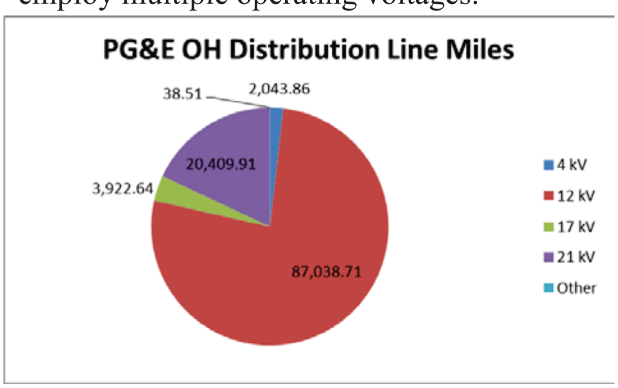
The separation of responsibility for managing gas and electric assets provides more focus on electric issues affecting safety, reliability, and other goals. The separation of transmission operations from distribution operations further increases the focus on electric distribution assets. The Asset Management group brings a more strategic approach to asset management.

C. Infrastructure Issues

Legacy infrastructure issues present challenges to varying degrees. It is a rare occurrence to find a major utility without any of these types of issues. The development of these issues might arise from a number of possible causes. A good example of a legacy issue is the distribution primary line voltage the utility uses to operate its system. Prior to WW II, 4 kV (4160kV Grounded wye/2400 volts) represented a common operating voltage for many small utilities. It is still in use today, both as a small system delivery voltage and also a usage voltage for large customers. These typically four-wire systems operate with three-phase conductors and a neutral. They could also take the form of a delta three-wire system without a neutral.

Over the years utilities have commonly found 4 kV systems too limiting in their ability to handle increasing amounts of power. Generally, 4 kV is considered today an obsolete operating voltage for a major utility. Many utilities have converted their 4 kV systems to a higher voltage, although some may still operate small 4 kV portions. The 12 kV level became the next higher common distribution voltage commonly chosen by utilities. However, in the past, standard voltages had yet to evolve. As a result many different, but similar operating voltages were selected.

Operating with voltages that are not optimum is a challenge for the industry. Overall replacement would be extremely difficult and costly. Many utilities, such as PG&E, therefore typically employ multiple operating voltages.



Two legacy PG&E issues raise system safety concerns. PG&E employs several distribution primary voltages. The first such concern arises from its unigrounded 12,470 volt three-wire system. A unigrounded system is only grounded at one primary voltage level point, which in PG&E's case is at the substation transformer. The circuits extend from the substation as part of a three-wire system (three phase conductors). A neutral conductor is not installed. This 12 kV system serves as the predominate voltage on the PG&E system (see the accompanying chart). Very few utilities use similar three-wire systems. The vast majority of the distribution systems put in place in the past forty years comprise four-wire, multi-grounded systems.

Clearing ground faults on the three-wire unigrounded system can be more problematic, when compared with multi-grounded, four-wire systems. On PG&E's 12,470 three-wire system, a wires-down situation (a broken wire contacting an object or the ground) will often remain energized until a Troubleman arrives and disconnects the power line source of feed. The resulting time lag until de-energization can create hazardous situations. PG&E's wires-down investigations show that, on average, multiple times daily, and thirty six percent of lines presently remain energized until the Troubleman arrives. Any downed power line is a hazard to the public until it has been grounded, even if the ground fault is cleared by an upstream protective device. The hazard arises from back feed from motors and generators. Hazards become much more pronounced when lines remain energized on the ground. This phenomenon on PG&E's extensive 12,470 volt three-wire system has contributed to a number of fatalities and injuries.

The second legacy issue of particular safety concern arises from the large amount of small size obsolete conductor remaining on PG&E's system. PG&E has 113,000 circuit miles of primary voltage overhead distribution conductor. A large portion (22,206 miles, or 19.6 percent) takes the form of #6 copper (Cu) conductor. This conductor was once popular, but is now recognized as obsolete, due to its small size. Such a small conductor becomes more subject to breakage as it ages. Three factors contribute to breakage risk. First, over many years of service, conductors will experience numerous situations of arcing together. High winds or lightning strikes are principal causes of arcing. These occurrences cause small pits in the conductor. Larger conductors can withstand this type of pitting without losing as material an amount of strength. Second, small copper wire anneals at lower fault current levels than does a larger conductor. Annealed copper becomes brittle and loses its strength. Third, a small conductor has a relatively low rated breaking strength. PG&E presently only purchases this conductor for replacement applications. PG&E also has 47,542 miles (41.9 percent of 113,000 circuit miles of primary voltage overhead distribution conductor) of #4 ACSR conductors (Aluminum Conductor Steel Reinforced) on its system. This type of conductor also raises safety concerns. ACSR conductor used a steel reinforcement core, usually with a zinc coating. Bimetallic corrosion between the aluminum and the zinc on the steel core in salt air makes ACSR conductor a suboptimum choice along coastal areas, where its use is no longer recommended.

Aging infrastructure represents a common utility industry issue. Equipment is not designed to last forever. Assets do not have unlimited lives. Utilities should address asset maintenance through continuous processes that address sustainability in a strategic manner. Unfortunately, such practices have not been commonly found in the industry. It has proven easy to put off replacements to save funding. Delays in replacements build the need for major response efforts to critical levels, as response can no longer be deferred. Asset replacement gaps can become too large to bridge without cost and often sacrifice to other goals. Drastic increase in repair, replacement, and maintenance funding has often been the result.

For electric distribution utilities, the aging infrastructure gap is a pitfall that has been difficult to avoid. This is due to several factors.

- Long service lives: A large portion of electric distribution assets are designed to provide safe, reliable service for extremely long periods. Distribution poles and conductors can last up to or over 100 years. Transformers can last over 50 years. Underground cable has a 40 to 50 year operating life. Stretching out the operating life of these assets produces a large amount of old assets operating ever closer to the brink of failure.
- Expansion has slowed: The 1950s to 1970s were a period of strong economic expansion. Much of the older infrastructure was replaced during this period. Utilities no longer face this type of growth. Assets must be replaced under maintenance planning programs rather than being forced into retirement due to load growth. In addition, the infrastructure added in the 1950s is now entering old age, and must be replaced.

- Funding priorities changed: With the advent of computers and lifestyle changes, the reliability levels of the past decades (30 or 40 years ago) have become no longer acceptable. Funding priorities were directed to reliability improvement projects and new technology. Aging infrastructure was not a priority.
- Replacement costs are high: The replacement costs of many electric distribution assets are much higher than their original cost. Inflation is one factor driving this increase, and is by itself, a major factor. Another factor increasing costs is that replacements must now often be replaced under energized conditions. Most of the original wood pole and conductor infrastructure was installed before lines were energized. Pole and conductor replacement must now be performed while the lines are energized at thousands of volts. This is a delicate and skilled job process that must be conducted under a number of safeguards in order to avoid injury. It is common for the cost of an energized pole replacement to be more than double the cost of a non-energized installation.

The combination of these factors makes it difficult to reverse an aging infrastructure trend. If allowed to develop, the financial gap becomes an obstacle requiring significant funding levels to overcome. Safety risks can also grow. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets. An asset management approach will ensure that adequate provision is made for future requirements and obligations.

We recommend the establishment of a formal asset management program in Electric Operations. Aging infrastructure is best addressed by having a strategic asset management program in place. These types of programs, such as the PAS 55 program, force a detailed and thorough condition assessment survey of the major assets. These types of formal programs also take failure modes into consideration. Long term sustainable plans can then be prepared to address the asset conditions. A sustainable asset management will mitigate system safety risks from aging infrastructure, which constituted a major portion of the safety items in this GRC.

We also recommend that PG&E treat aging infrastructure as an enterprise-level risk. Maintenance of the assets should be a continuous process conducted in a sustainable strategic manner. It is far too easy to put off the replacement to save maintenance funding. As the replacements are delayed, the magnitude of the financial implications of getting behind becomes too severe to overcome. Safety risks can also develop. The primary tool for avoiding this pitfall is a strategic infrastructure plan that addresses all major assets. An asset management approach will ensure that adequate provision is made for future requirements and obligations.

D. Electric Operations Risk Program

1. Enterprise Risk Management from 2006 to 2011

PG&E started an ERM Program in 2006, with the goal of identifying and managing top Enterprise-level risks. A dedicated ERM principal managed the program, drawing support from a team (in part-time roles) from across the enterprise. The program used a two-year cycle of risk identification and mitigation. PG&E identified potential risks through brainstorming sessions, which led to development of a list of enterprise-level risks.

The resulting list of risks was presented to the officer team, which voted on the final list. PG&E classified risks as enterprise or as operating level. Enterprise-level risks underwent formal reviews by upper management. Significant operating risks not classified as enterprise-level were managed by the appropriate officer owner, but did not undergo formal review. Each enterprise-level risk and operating risk was assigned to an Officer as the owner. For each risk, an individual within the applicable Officer's line-of-business was assigned responsibility managing that risk as part of the individual's overall responsibilities.

This process produced the identification of three Electric Operations enterprise-level risks associated with system safety. These risks appeared on every risk list from 2006 to 2011. The names changed from year to year, but the risks remained in essence the same.

Electric Operations Enterprise-Level Risks

2006	2008	2010
Gas and Electric Distribution Safety Conditions	System Safety	System Safety
Seismic	Seismic	Seismic and Tsunami
Urban Fire	Urban Wildland Fire	Wild Fire

PG&E has occasionally revised the wording of the risk definitions. The current definitions are:

- *Seismic & Tsunami:* The occurrence of a large-magnitude earthquake that would threaten worker and system safety, cause unacceptable damage, and hinder timely response to emergency conditions or timely restoration of gas and electric utility service.
- *Wildfire:* Risk from wildfires resulting from PG&E's activities or asset contact with vegetative fuels.
- *System Safety:* A system condition that PG&E knows, or should reasonably know, could cause a hazardous event, but does not take expeditious or sufficient action to mitigate.

In response to the identified enterprise-level risks, Electric Operations assessed the risk drivers and developed mitigation plans. Electric Operations prepared and presented a wildfire mitigation plan to the Board of Directors on December 19, 2006. The conclusion of the mitigation plan was as follows:

> *While the probability may be low that a major urban wildland fire could be caused by PG&E, the consequences are potentially very high. In addition to the risk management activities already in place, PG&E has identified additional actions to potentially reduce the probability of a fire caused by PG&E, and improve PG&E's emergency response capability. A plan has been initiated to evaluate and implement these actions and to identify additional risk reduction opportunities.*

The additional planned actions included:

- Performing additional patrols and inspections in the highest risk areas prior to the 2007 fire season
- Employment of eight arborists
- Modifying training programs in 2007 to enhance wildland fire content.

Electric Operations updated the wildfire mitigation plan in February 16, 2010. The conclusion of this mitigation plan was as follows:

> *Events in Southern California have served to highlight the risk of an urban wildland fire to utilities operating in California. PG&E continues to learn from*

the Southern California utilities' experiences, and continues to make progress to mitigate this risk.

In 2007 PG&E prepared a Seismic Risk Management Plan. Since its 1985 inception, the PG&E Geosciences Department has provided guidance for the Company's seismic risk management program. This program's six major elements included dedicated staff, budget, and accountability. This program allowed PG&E effectively to manage earthquake risks and comply with the intent of the California Earthquake Hazards Reduction Act. The conclusion of the mitigation plan was:

> *PG&E recognizes that seismic risk is a fundamental element of our operations. Risk management activities have been implemented to reduce the risk to our physical facilities, and to support our ability to respond effectively to, and recover from, seismic events.*

On September 18, 2007, ERM presented a Gas & Electric System Safety Risk Management Plan to the Board of Directors. The mitigation plan's conclusion was:

> *As a result of the ERM review, the Utility has identified additional steps to be taken in order to enhance the safety of our gas and electric T&D systems. These steps are expected to address deficiencies that have been raised by employees or that have been highlighted by recent system safety events. Information obtained through evaluations of system safety events will continue to be fed back into the ERM process for additional analysis.*

The additional steps included the following key activities:

- Implementing an Effective Asset Registry Program
- Improving Tracking of Program Implementation
- Emergency Response
- Analysis of Key Information Sources:
- Implementing a Gas Distribution System Integrity Program.

In alignment with ERM guidance, Electric Operations historically used a spreadsheet risk assessment tool for the documentation and analysis of enterprise risks prior to 2012. ERM labeled this spreadsheet as a "Template 3." ERM did not actively edit or maintain the historic Template 3 spreadsheets, but did review them during Electric Operations' regular recurring analyses of enterprise risks. Electric Operations completed the last active Template 3 for System Safety risk in May 2011. Liberty's review of this template noted that the risk assessment included an analysis of specific threats, high consequence event risk drivers, inherent risk impact ratings, residual risk ratings and evaluations of all existing and proposed mitigation efforts. However, the analysis was for an explosion or fire risk caused by electrical transmission components only. Distribution components were not considered.

2. Changes Following San Bruno

On September 14, 2010, just five days after San Bruno, ERM presented a System Safety Risk update to the Board of Directors. This presentation's treatment of System Safety risk defined a system safety event is defined as:

- A single significant event occurring in a defined high population density area associated with gas or electric transmission and distribution (T&D) facilities; or
- Multiple significant events, independent of geography, resulting in fatalities or severe injuries and occurring within a short to medium time period.

For electrical facilities, ERM gave an example of such events. Explosions or fires could be caused by:

> *Underground electric T&D equipment (in vaults and under manholes), energized oil-filled equipment in substations, aged equipment that has not been replaced, or known defective equipment that has not been taken out of service.*

ERM cited as an additional planned action regarding electrical facilities the establishment of an inventory of aging high-risk electric system assets and an associated work plan for replacement.

Early 2011 witnessed much change in the Electric Operations organization. Risk assessment activities at that time occurred on two tracks. In 2011 PG&E decided to overhaul its Enterprise Risk Management program to focus on operational risks. This track created a formal approach to risk assessment. A second track revolved around the Electric Operations Improvement Plan. This track was associated with the operational reorganization and improvement within Electric Operations, and involved a less formal risk assessment and a more immediate focus on actions to mitigate known risks. We discuss these two tracks separately below.

In 2011 PG&E decided to overhaul its ERM program as discussed in Chapter II of this report, in order to focus better on operational risks. Electric Operations followed this new program. In September 8, 2011 Electric Operations developed an Improvement Plan. The next section of this report discusses that plan in some detail. With respect to system safety and risk assessment planning, the plan contained an action identified as "Implement risk-based framework." This item called for the LOP to develop and implement methods to identify and prioritize system safety risk, and to formulate strategies to mitigate the occurrence and impact of safety events. The action also called for allocation of resources based on probability of occurrence and severity of impact, informed by asset characteristics, geography, and population density. The timeframe for developing and implementing this risk-based framework was 2012. Throughout the 2012 period Electric Operations started on its journey to develop and implement this framework.

In December, 2011, PG&E management instructed the LOBs to form their own Compliance and Risk Management Committees (CRMC). The first meeting of the Electric Operations CRMC occurred on February 17, 2012. At that time Electric Operations also started developing a Risk Register of the business unit's operational risks.

Additional meetings of the Electric Operations CRMC occurred throughout 2012; *i.e.*, in March, April, May, July, and September. Electric Operations adopted a working definition of System Safety risk, which the unit used throughout the conduct of its risk management activities in 2012. This definition is reflected in the RPC updates and Electric Operations Compliance and Risk Committee updates on System Safety risk. This definition includes the Board definition; however, it provides additional clarity around the potential areas of concern; *e.g.*, personal injury or fatality (public or employee). It is as follows:

> *A system condition associated with electric transmission, substation, or distribution facilities that could directly lead to personal injury or fatality of either the public and/or employees. The risk is that the Utility knows, or should*

reasonably know, about such a condition but does not take expeditious or sufficient action to mitigate it.

In March 2012 management directed the LOBs to prepare a three-year improvement plan as part of their ERM activities (S1 playbook). Electric Operations already had a three year improvement plan in place titled the Electric Operations Improvement Plan.

On November 1, 2012, the Electric Operations officially published the unit's Risk & Compliance Committee Charter. In December the Electric Operations RCC released its first register of key operational and operational risks. At that time the items on this register were still under evaluation and review. This risk register is shown below.

Initial Electric Operations Risk Register Items

Enterprise Risks	Key Operational Risks	Operational Risks
Seismic	Electric substation physical reliability and security[1]	OH Conductor –Wires Down
Wildfire	Disaster recovery[1]	Structural Failures (*e.g.*, Poles)
System Safety	Business continuity[1]	Oil-filled switches (*e.g.*, TGRAM/TGRAL)
	Encroachments (transmission and distribution easements) [1]	Network transformers/protectors
	Qualified workforce[1]	Work procedure errors
	Co-located electric substations and gas transmission	Car-pole accidents
	Catastrophic substation equipment failure	T/D cable termination failures
	Fire in indoor urban substation	Third party access to facilities
	Dig-in to underground transmission	Joint poles or joint trenches

1. These items were identified as risks prior to the advent of the Operational Risk Management framework.

The Electric Operations Improvement Plan has focused Electric Operations' recent actions to mitigate safety risks, particularly with respect to system and public safety and employee safety. PG&E did not begin that plan with a formal assessment and analysis of risk and no risk-based plan existed within Electric Operations through the time of GRC forecast preparation.

The Improvement Plan arose from a June 21, 2011, Electric Operations presentation of a sixty-day turnaround plan to top management. This plan included the development of a three-year improvement plan, calling for development of a risk-based framework and an organizational redesign. In developing this turnaround plan, Electric Operations defined what was working well and which areas needed improvement. The unit identified five focus areas: Reliability, Safety, Compliance, Customer Satisfaction, and Work Efficiency. The Electric Operations Improvement Plan's treatment of system safety contained the following high level categories:

- *Implement risk-based framework:* Develop and implement methods and approaches for identifying and prioritizing system safety risk; formulate strategies to mitigate occurrence and impact of safety events; allocate resources based on probability of occurrence and severity of impact, informed by asset characteristics, geography, and population density; actively seek and incorporate field concerns in allocating resources.
- *Benchmark to know what success looks like*: Benchmark in and outside the utility industry to better inform risk-based methods and approaches.
- *Continue "no regrets" actions:* Mitigate known issues including San Francisco network deficiencies and wildfires.
- *Improve data quality:* Use technology to improve ability to track, analyze, and maintain accurate information to ensure use of results to refine safety strategies.
- *Emergency Response:* Use technology and better coordination with local emergency response to limit impact of any safety events.
- *Engage customer community:* Use outreach campaign to raise customer awareness of electrical safety to prevent third-party contacts.

The plan also sought to use existing knowledge of enterprise risk to inform asset strategy. It also provided general guidance to focus on incidents that could reduce five "high consequence" metrics in the area of public/system safety; *i.e.*, equipment failures, wildfires, third-party contacts, dig-ins, and wires down.

The Electric Operations three-year Improvement Plan formed the basis of the 2012-2013 work plans and the 2014-2016 GRC forecasts. In addition to the asset plans in the Improvement Plan, Electric Operations concurrently developed a reorganizational plan to accomplish these improvements. (See Section A for more detailed information on this organization.) The Improvement Plan at that point contained seven focus areas: public/system safety, employee safety, reliability, compliance, customer satisfaction, work efficiency, and technology enablers. The Improvement Plan contained system safety initiatives classified as acceleration of existing base plans or as new initiatives:

- Acceleration of existing base plan initiatives
  - Swiveloc manhole cover replacement program
  - Addressing wood pole replacement backlogs
  - Underground oil switch replacements
  - Replacing non-exempt equipment in urban wildfire areas
  - GIS/AM system project implementation
  - Mapping data quality improvement
  - Operating data in industry standard platform
  - Coordination with local agencies
- New initiatives
  - Implementing a risk-based framework
  - Replacements of network high-rise transformers
  - Data quality improvements
    - Health of records (field verification)
    - Convert Technical Library into documentation
    - Scan all records and drawings
  - Train employees on emergency response
  - Outreach campaign.

In addition to the system safety focus area mentioned above, the Improvement Plan contained six other focus areas. Several of these focus areas contained initiatives that Liberty found to also have an impact on system safety. In the reliability focus area, several of the initiatives were later connected with system safety. Testimony in the GRC work papers also later connects these initiatives with system safety. These reliability initiatives were:

- Acceleration of base plans
  - Underground cable replacement program

- EC tag backlogs
- New initiatives
  - Overhead conductor replacement program
  - Network cable replacement program
  - Increase SCADA penetration.

The focus area of technology enablers also contained an initiative related to system safety, titled "emergency management tools." Throughout the end of 2011 and in 2012 Electric Operations continued to update and refine its Improvement Plan.

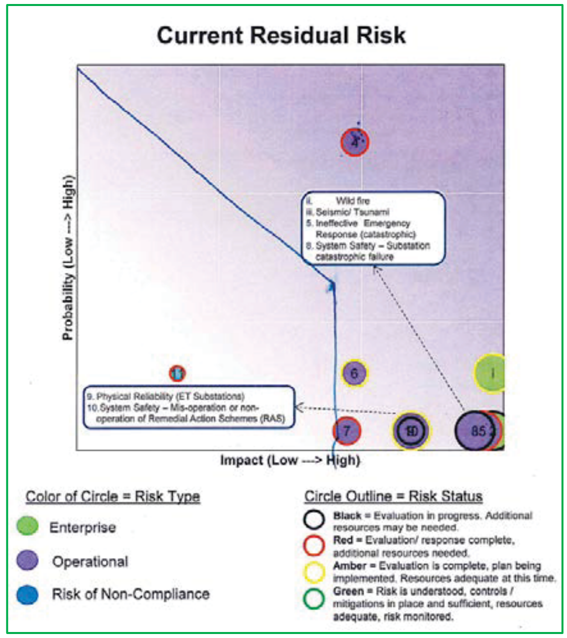
3. Current Status/Future Directions

As discussed in Section B, the centerpiece of Electric Operations' current approach to mitigating safety risks focuses on the Electric Operations Improvement Plan, particularly within the public/system safety and employee safety key focus areas. The mitigation of safety risks is largely organized around PG&E's assets and system operations. The implementation of the ORMP within Electric Operations is not complete, but is well underway. Electric Operations is continuing to identify and prioritize risks. PG&E is presently scoring these operational risks. The risk scoring requires further calibration, which PG&E anticipates will occur in 2013. In the interim, PG&E is exercising its judgment to determine which risks Electric Operations will pursue in the near term.

Risk #	Risk
i	Cyber Security
ii	Wild fire
iii	Seismic/ Tsunami
4	System Safety – Distribution Overhead Conductors (primary voltage)
5	Emergency Response (catastrophic)
6	System Safety –Transmission Overhead Conductor
7	System Safety — Distribution Support Structures (poles, framing, guying, and insulators)
8	System Safety – Failure of Substation (catastrophic)
9	Physical Reliability (ET Substations)
10	System Safety – Mis-operation or non-operation of Remedial Action Schemes (RAS)
11	Risk of Non-Compliance

On February 28, 2013, Electric Operations completed a draft of the Risk and Compliance (formerly called "Session D") templates. The Risk and Compliance module comprises the part of PG&E's Integrated Planning process that focuses on risk and compliance. Each April (beginning with 2013 as a test case), LOB personnel will discuss with senior officers their top risks, top compliance requirements, and their plans for managing them.

The new risk register list is shown in the table to the left. System safety risks are now listed on the component level rather than as one risk. The risks pertaining to distribution items are Distribution Overhead Conductors, Distribution Support Structures, and Failure of Substation (catastrophic).



Some of the risks listed in the December 2012 on the release of the first risk register are no longer present. These risks are oil-filled switches (*e.g.*, TGRAM/TGRAL), network transformers & protectors, T/D cable termination failures, and work procedure errors.

As shown in the accompanying "heat map," some of these ten risks have been evaluated while some have not. The evaluations in the risk and compliance session templates included the mapping of risk drivers and controls. Note that Operational Risk #4 – (System Safety – Distribution Overhead Conductors) has been evaluated as having a high probability and high impact residual risk. It is at a noticeably different level of risk from the others.

4. Status of Major Safety Programs

We found wildfire mitigation risk planning to be an ongoing and successful process since 2006. Well before the ERM program was identified in 2006, Vegetation Management had taken the lead in changing the vegetation program to focus on wildfire prevention. As discussed further in Section E.7 of this report, PG&E has reduced vegetation-caused wildfire ignition events. They have prepared and executed formal wildfire mitigation risk planning since the ERM program was formed in 2006. Seismic mitigation risk planning has had a similar history. Since its inception in 1985, the PG&E Geosciences Department has provided guidance for the Company's seismic risk management program. Seismic risk mitigation activities for Electric Operations distribution facilities have involved buildings and substations. This area receives more detailed treatment later in this chapter of our report.

We found that no formal risk-based assessments underlie the safety initiatives addressed in the GRC. Electric Operations has been clear about its position and direction with respect to system safety and the GRC. A risk-based framework is only emerging in Electric Operations. One of their primary Improvement Plan initiatives is to develop and implement a risk-based framework which can be used to aid future asset strategy decisions. This does not mean that safety risks have not been considered in preparing the GRC initiatives. PG&E used its existing knowledge of known system and enterprise risks to inform its asset strategy decisions. Liberty has found evidence of this throughout the detailed review of the GRC safety initiatives. Another risk-based factor in selecting the initiatives was to reduce the five "high consequence" metrics of public/system safety: equipment failures, wildfires, third-party contacts, dig-ins, and wires down.

Some progress in implementing a more structured, risk-based planning framework in Electric Operations has occurred, but it has not been marked by rapid progress. Electric Operations has been cautious in formal risk assessment identification and scoring of the risk. They have lagged behind the other LOBs in implementing ORMP. However, the unit has made progress according to the schedules set by the ERC and is on track in implementing ORMP. The program appears to be headed in a good direction and appears to have a generally sound basis.

The operational risks are now more narrowly defined, and targeted towards the electric incident history. Since the original improvement plan was issued in September 2011, PG&E's recognition of the overhead primary conductor risk has markedly improved.

E. Electricity Distribution Project and Spending Analysis; GRC Exhibit 4

1. Background

The financial forecast for the GRC is well documented in the testimony and work papers. The expense forecast for 2014 is $60.8 million higher than 2011 recorded costs. The primary drivers PG&E cited are improving system safety through increased expenditures for vegetation management, line maintenance, and asset and records management systems. The capital forecast of $1.770 billion in 2014 is $400 million higher than 2011 recorded costs. The primary drivers

PG&E cited are system safety, reliability and automation, replacement of assets that have reached the end of their useful life, and new customer connections.

Liberty reviewed the safety and security proposals related to the electric distribution system to:

- Provide stakeholders and the Commission information on the quality and cost-effectiveness of the safety and security proposals made by PG&E
- Review PG&E's proposals and compare them to industry best practices and standards.

Among the key questions we considered were:

- Has PG&E adequately assessed the physical condition of its system (physical assets and systems)?
- Are the projects prioritized by PG&E those that will address and mitigate the risks to system safety identified in the risk assessments?
- Appropriateness: Is the level of funding just and reasonable to mitigate the identified risks to system safety?

PG&E has not quantified the dollar expenditures of "safety enhancements" in its GRC because of difficulty in forming a precise and mutually exclusive definition of safety. As discussed earlier, PG&E considers safety to be one of three central pillars for planning its operational commitments. Safety forms a core element of PG&E's mission and values. Moreover, for electric operations, safety and reliability (another core mission element) are strongly intertwined.

	Dollars in Thousands					
	2012	2013	2014	2015	2016	Source
Total Electric Distribution Capital Forecast	1,465,000	1,591,000	1,770,000	1,827,000	1,909,000	Exh. (PG&E-4), Ch. 1, Page 1-20, Lines 21-24
Driver - Safety	891,181	919,602	1,010,310	1,009,780	1,028,688	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01[1], Line 950
Driver - Safety as a Percent of Total Electric Distribution Forecast	61%	58%	57%	55%	54%	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01,Line 954
Driver - Reliability	196,554	218,896	211,700	223,148	226,745	GRC2014-Ph-I_DR_Liberty_001_Q043Atch01,Line 951
Drivers - Safety and Reliability as a Percent of Total Electric Distribution Forecast	74%	72%	69%	67%	66%	GRC2014-Ph-1_DR_Liberty_001_Q043Atch01,Line 955

Therefore, it is fair to conclude that a large majority of PG&E's forecasted Electric Operations expenditures have at least an indirect connection to safety. The accompanying table demonstrates that PG&E has taken a very inclusive approach in connecting proposed expenditures to safety enhancements, recognizing that reliability and safety are closely related. Outages, for example, have direct reliability consequences, but can also result in live wires on the ground, cut power to critical infrastructure and people with medical needs, and cause traffic accidents, wildfires and other serious safety issues.

In developing the preceding table, PG&E began from a list of capital orders that appear in the results of operations model for the 2014 GRC, and which comprises a portion of the capital expenditure forecast for Electric Operations. PG&E assigned the orders contained in the attachment to "project driver" codes (including safety) for purposes of responding to DRA Data Request 001. In assigning these codes to the orders, PG&E did not use the above definition relating to system safety (*i.e.*, a system condition that PG&E knows, or should reasonably know, could cause a hazardous event, but does not take expeditious or sufficient action to mitigate) nor did PG&E subject the items on the list to structured safety risk assessment.

2. Definitions

Our review sought to craft a set of definitions that would permit us to distinguish safety-related Electric Operations projects and programs from others. We developed the following categories, in order to avoid what would amount to a nearly all-encompassing definition of safety-related work. The categories we applied were:

- ***Safety Initiative***: A specific project outside of the normal base activities in the GRC that is primarily targeted to mitigate a safety or security residual risk. The current residual risk is not acceptable. The project or program is not currently in the base activities.
- ***Supporting Initiative***: These initiatives comprise projects or programs in support of the distribution system and distribution operations.
- ***Base Activity***: These activities fall within what is generally considered to be normal business for electric distribution. They might relate to safety, operations and/or reliability. Managed properly, the residual risk of the base activity is currently acceptable.

- ***Reliability Initiative***: A project or activity outside of the normal base activities that is primarily targeted to reliability improvements. Such initiatives may have a tangential impact on system safety. However, they are designed and managed primarily to mitigate a reliability rather than a safety risk.
- ***Operations***: These activities primarily support electric operations. They are designed and managed primarily to support operations rather than to mitigate a safety risk.

Liberty found the encompassing approach that PG&E originally took in defining GRC safety initiatives too broad to make analysis from a safety perspective practicable. Liberty asked that PG&E reclassify distribution work as follows to facilitate our analysis:

- Falls "above the base activity level" (as requested by Liberty)
- Reasonably constitutes a system condition that PG&E knows, or should reasonably know, could cause a hazardous event, in the absence of mitigation.

We recognize that a significant portion of base activity level expenditures is safety related. Examples include work associated with distribution line patrols and maintenance tags (Exhibit PG&E-4, Chapter 5), pole test and treat and pole replacement (Chapters 6 and 7), vegetation management (Chapter 8) and emergency recovery (Chapter 10).

The resultant list of GRC items which PG&E provided fell in reasonably close agreement with the listing that Liberty made by following our classification system. The table below illustrates the difference in the two listings. The percentages shown are of the total electric distribution GRC forecast (from Exhibit 4).

Liberty/PG&E Classification of Safety Expenditures

	2014 Forecast	2015 Forecast	2016 Forecast
System Safety Initiatives - Liberty	16.7%	20.0%	19.3%
System Safety Initiatives - PG&E	18.6%	23.1%	25.0%

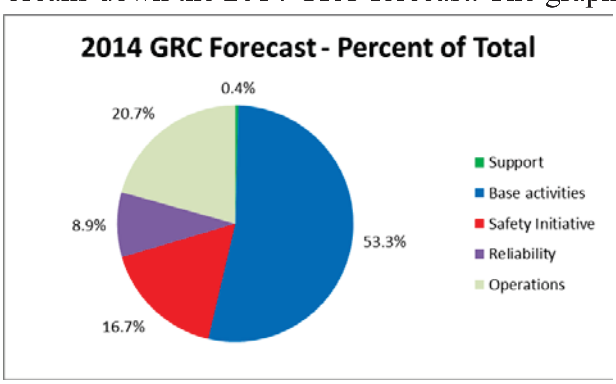
PG&E noted that its forecast for certain line maintenance work (Chapter 5 and Chapter 7) for 2012 and 2013 includes expenditures above what the Company would consider as base activity.

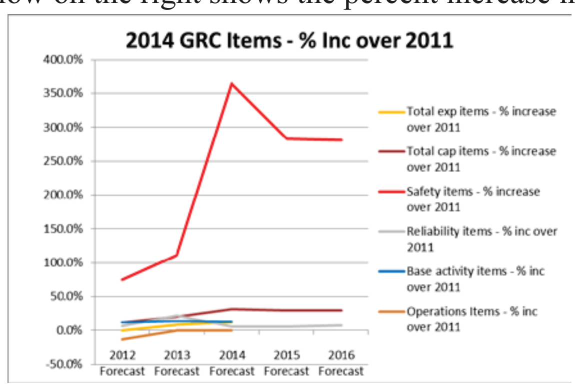
While safety related, PG&E is making these additional expenditures in 2012 and 2013 as a result of changes the Company made to the electric distribution maintenance program in 2010 (see Exhibit PG&E-4, Chapter 5, pg. 5-1, line 26). Consequently, PG&E did not include those expenditures in response to Liberty's request. Liberty agrees with this approach.

PG&E's forecast (Exhibit 4 Chapter 13) also includes several substation transformer and switchgear replacement projects. While safety related, PG&E did not include these expenditures in this response because the Company considers these projects as base-level activity, even though the absolute value of the expenditure forecast can vary from year-to-year depending on the complexity and timing of specific projects. Liberty agrees with this approach.

Finally, PG&E reiterated the strong relationship it perceives between reliability and safety. For example, while initiatives such as the Company's targeted circuit initiative (Exhibit PG&E-4, Chapter 15, pp. 15-21) and Fault Location, Isolation and Service Restoration (FLISR) projects (Exhibit PG&E-4, Chapter 15, pp. 15-20) are primarily intended to improve reliability, they also provide safety benefits. However, because PG&E is proposing such projects primarily from a reliability perspective, they were not included. Liberty agrees with this approach.

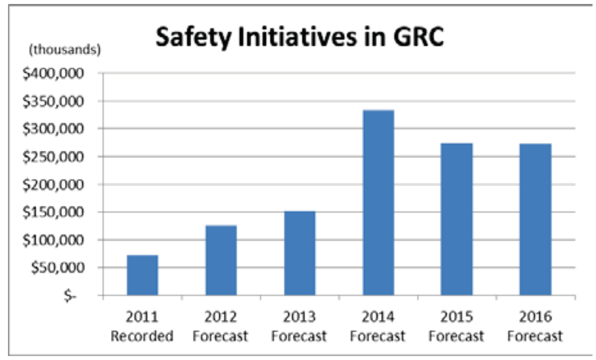
Using the safety initiatives identified from the Liberty classification structure, the next pie chart breaks down the 2014 GRC forecast. The graph below on the right shows the percent increase in

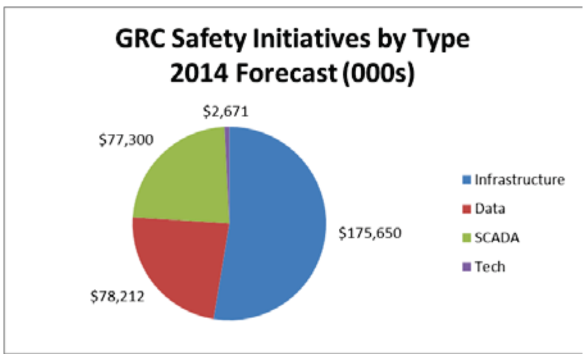


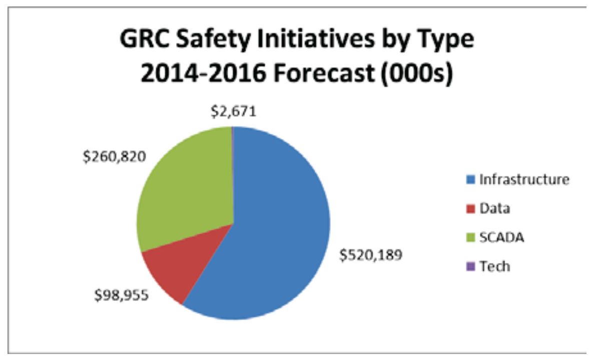


2014 forecast items over 2011 recorded data. The number of system safety projects, programs, and activities are numerous. Liberty has organized them into forty groupings in Section D below, most of them according to how PG&E presented them in the GRC work papers.

The annual safety initiative expenditures in Exhibit 4 are shown in the graph on the right. Liberty also classified each of the initiatives as either infrastructure, data, SCADA or general technology. These classifications are shown in the graphs below. As targeted in the Improvement Plan, mitigating known issues (infrastructure), improving data quality (data and SCADA) and emergency response (technology and SCADA) represent the major emphasis in these GRC items.







3. Liberty's Classification of System Safety Projects

The term "quantified risk assessment" refers to assessing the frequency of an event and its measurable consequences (fatalities, injuries, damage). Failure rates and linkages to cause must be known to a large degree. PG&E used neither as a basis of this GRC, nor was either available at the time of its preparation. In general, the data set for developing a fully quantified risk assessment for the electric distribution system will rarely, if ever, be available. The general nature of system threats, vulnerabilities, and consequences can be defined. Data to quantify the likelihood of the event might occasionally be known. The costs of risk mitigation plans should always be possible. The system impacts of risk mitigation can also occasionally be calculated. A quantification of the safety impacts of the mitigation will rarely be known.

Many of the initiatives to be evaluated comprise fairly straightforward infrastructure replacement projects. For the vast majority of the distribution infrastructure replacement, a like-for-like replacement is the only feasible alternative. For nearly all of these infrastructure replacement items, the only alternative is timing.

We found that the system safety risk mitigation items in the GRC consist mainly of aging infrastructure replacement and SCADA additions. Over 88 percent of the identified GRC system safety initiatives consist of replacing aging infrastructure and adding SCADA capability. This result conforms to the stated direction of the Electric Operations Improvement Plan to continue "no regrets" actions (mitigate known issues), enhance data quality and improve emergency response.

We also found that the system safety initiatives in the electric distribution portion of this GRC are main contributors to the increased forecast levels over 2011. The identified system safety initiatives constitute fewer than twenty percent of the electric distribution GRC items. As a group these items are over 300 percent above the recorded 2011 expenditure levels. The items identified as reliability, base operations and support are about twenty percent above the recorded 2011 expenditure levels.

4. Incident History

The tables below show CPUC-reportable electrical contact incident history. The vast majority of third-party vehicle/pole collisions are not captured in this CPUC metric, but is tracked internally. Only collisions that involve contact with energized facilities are CPUC-reportable. We made the following observations:

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)		
Cause	Count	% of total
Vehicle strikes equipment [2]	22	30.1%
Foreign object	12	16.4%
Vandalism and theft	12	16.4%
Tree trimming	8	11.0%
Accidental contact (other)	5	6.8%
Communication worker	4	5.5%
Electric work - other	4	5.5%
Aircraft	3	4.1%
Dig-in	3	4.1%
Grand Total	73	100.0%

- Electric distribution system accounts for over 88 percent of the incidents.
- Third party contacts are by far the highest incident category at 73 percent.
- Employee contacts constitute about 22 percent.
- PG&E recorded three reportable equipment failure injury incidents since April 2004. About 7,200 equipment failures occur each year (excluding major storm days and transformer only outages).

These three recorded equipment failure incidents consisted of the following:

- August 19, 2005 - A failure occurred in the primary compartment of a network transformer. Burning oil and gasses were ejected from the vault through the manhole covers in an explosion, which damaged nearby buildings and injured a pedestrian.
- March 11, 2009 - A third-party fiber optic cable technician line-worker made contact with a down guy wire that was energized due to an overhead 12 kV line conductor that had come loose.
- April 3, 2012 - A PG&E cable splicer received an arc flash while closing a switch in a manhole. The switch catastrophically failed in the process of closing.

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)		
Cause	Count	% total
Third-Party [1]	73	69.5%
Employee related	23	21.9%
Force majeure	5	4.8%
Equipment failure	3	3.8%
Grand Total	105	100%

CPUC-Reportable Injuries/Fatalities (April 2004 - April 2012)		
EO Subsystem	Count	% total
Distribution	93	88.6%
Substation	2	1.9%
Transmission	10	9.5%
Grand Total	105	100.0%

In addition to these three incidents, a fourth equipment failure incident occurred on April 20, 2012. A primary conductor failed and landed on a truck which was parked. The line remained energized. The occupant was killed when exiting the vehicle.

Vehicle strikes-equipment comprise another general category. Vehicle/pole incidents total more than 1,500 annually. Only the incidents involving electrical contact are CPUC-reportable. Car hits after which primary conductors fall down and remain energized are common. The past two years (2011 and 2012) witnessed four occurrences in which car occupants contacted energized conductors. Three involved fatalities.

We discuss employee and contractor fatalities later in this chapter. Overall, eight fatalities occurred in 2012.

- Two - Car wreck and energized downed conductors
- One – Equipment failure and energized downed conductor
- Four – Contractor fatalities (one was in the Energy Supply area)
- One – Employee fatality (motor vehicle accident)

5. Exhibit 4 – Chapters 2 To 4 – Technology, Mapping, & Records

a. Description

The table below lists the initiatives in these chapters along with Liberty's classification of each initiative. The system safety initiatives are highlighted in yellow.

GRC Exhibit 4 Technology, Mapping, & Records Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety per PGE & Liberty	Electric Operation Technology	2	Emergency Response Tools (electric & gas)	Cap	2F				$ 2,404		
Safety per PGE & Liberty	Electric Operation Technology	2	Emergency Response Tools (electric & gas)	Exp	JV			$ 1,499	$ 267		
Safety per PGE & Liberty	Electric Operation Technology	2	Data Historian for Electric Distribution	Cap	2F				$ 12,278	$ 10,940	$ 983
Safety per PGE & Liberty	Electric Operation Technology	2	Data Historian for Electric Distribution	Exp	JV			$ 365	$ 206		
Safety per Liberty	Electric Operation Technology	2	Outage Reporting and Analysis System Replacement	Cap	2F			$ 3,258	$ 4,516		
Safety per Liberty	Electric Operation Technology	2	Outage Reporting and Analysis System Replacement	Exp	JV			$ 235	$ 362		
Operations	Electric Operation Technology	2	Closed Loop SmartMeter™ Outage Management Integration	Cap	2F					$ 2,904	$ 2,892
Operations	Electric Operation Technology	2	Closed Loop SmartMeter™ Outage Management Integration	Exp	JV					$ 1,181	$ 1,175
Operations (Safety per PGE)	Electric Operation Technology	2	Advanced Applications for Distribution Control Centers	Cap	2F					$ 3,811	$ 5,661
Operations (Safety per PGE)	Electric Operation Technology	2	Advanced Applications for Distribution Control Centers	Exp	JV					$ 405	$ 602
Operations	Electric Operation Technology	2	Work Design and Management Projects	Cap	2F		$ 3,100	$ 4,770	$ 7,384	$ 14,613	$ 9,514
Operations	Electric Operation Technology	2	Work Design and Management Projects	Exp	JV		$ 2,118	$ 2,847	$ 6,090		
Operations (Safety per PGE)	Electric Operation Technology	2	Workforce Mobilization & Scheduling Projects	Cap	2F		$ 754	$ 13,287	$ 15,407	$ 28,118	$ 29,363
Operations (Safety per PGE)	Electric Operation Technology	2	Workforce Mobilization & Scheduling Projects	Exp	JV		$ 331	$ 1,008	$ 2,971		
Safety per PGE & Liberty	Electric Operation Technology	2	SCADA Platform Upgrade & System Enhancements	Cap	2F					$ 5,849	$ 18,250
Safety per PGE & Liberty	Electric Operation Technology	2	SCADA Platform Upgrade & System Enhancements	Exp	JV					$ 929	$ 3,292
Safety per PGE & Liberty	Electric Operation Technology	2	Electric Distribution GIS/Asset Management	Cap	2F	$ 2,889	$ 22,200	$ 32,183	$ 27,805	$ 2,000	$ 2,000
Safety per PGE & Liberty	Electric Operation Technology	2	Electric Distribution GIS/Asset Management	Exp	JV	$ 1	$ 1,449	$ 1,475	$ 1,830		
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Based Maintenance – Asset Data Analysis & Storage	Cap	2F					$ 2,461	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Based Maintenance – Asset Data Analysis & Storage	Exp	JV					$ 838	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Management Tool for Public Safety	Cap	2F				$ 1,466	$ 1,371	
Safety per PGE & Liberty	Electric Operation Technology	2	Asset Risk Management Tool for Public Safety	Exp	JV				$ 349		
Support	Applied Technology Services	3	Supports work efficiency, reliability and general safety	$ not included - minor $ among three MWCs							
Base Activity	ED Mapping and Records	4	Base Mapping and Records Management	Exp	GE	$ 3,364	$ 3,944	$ 4,563	$ 4,688		
Safety per PGE & Liberty	ED Mapping and Records	4	Field Asset Inventory	Exp	GE		$ 3	$ 2,800	$ 10,000		
Safety per PGE & Liberty	ED Mapping and Records	4	Convert paper-based records to electronic format	Exp	GE			$ 1,000	$ 14,200		
Safety per PGE & Liberty	ED Mapping and Records	4	Update electronic records to standard format	Exp	GE			$ 1,000	$ 1,000		
Safety per PGE & Liberty	ED Mapping and Records	4	Records quality assurance program	Exp	GE		$ 300	$ 400	$ 400		

Liberty's classifications did not agree with those of PG&E in three areas:

- *Outage Reporting and Analysis System Replacement:* Liberty classified this as a system safety initiative and PG&E did not. (See subsection b. below).
- *Advanced Applications for Distribution Control Centers:* PG&E classified this area as a system safety initiative; Liberty did not. PG&E felt that this initiative would enable improvements in safety, compliance, documentation, customer satisfaction, reliability and work efficiency. Liberty agrees, but also felt the initiative is primarily targeted to the Distribution Control Center Consolidation application, rather than to mitigating an identified system safety risk.
- *Workforce Mobilization and Scheduling Projects:* PG&E classified this as a system safety initiative; Liberty did not. PG&E felt that this initiative would enable improvements in safety, compliance, documentation, customer satisfaction, reliability and work efficiency. Liberty considers this initiative to be targeted primarily at work efficiency improvements.

Seventeen separate IT project groupings fall into this GRC chapter. Liberty requested that PG&E classify these projects as a new initiative, a system which is lagging behind current industry, or a system that is "broken" (dysfunctional). The next table shows PG&E's classifications. The system safety related projects are highlighted. PG&E did not classify any of the systems as dysfunctional. Liberty questions whether the two asterisked projects can be so classified.

Classifications of IT Projects

Project	New Initiative	Behind Industry
Emergency Response Technologies		X
Data Historian for Electric Distribution		X
Outage Reporting and Analysis System Replacement (Safety per Liberty)*		X
Closed Loop SmartMeterTM Outage Management Integration	X	
Advanced Applications for Distribution Control Centers (Safety per PG&E)	X	
SCADA Platform Upgrade & System Enhancements	X	
Electric Distribution Geographic Information System/Asset Management*		X
Asset Risk Based Maintenance – Asset Data Analysis and Storage	X	
Asset Risk Management Tool for System Safety	X	
Graphic Work Design		X
Capital Asset and Expense Planning System Enhancements	X	
SAP Work Management Enhancements (Plant Maintenance Module)	X	
Project Management and Reporting Toolset Enhancements		X
Customer Connections Online Tools		X
Workforce Mobilization by Field Crew or Work Type		X
Work Scheduling and Dispatch System Consolidation	X	
Scheduling Integration with Time Keeping Systems		X

For purposes of responding to this request, PG&E characterized technology projects as a "New Initiative" in cases where its technology in the area is currently up to date and the proposed project will keep PG&E on pace with industry trends. These projects differ from projects in the "Behind Industry." In those cases, PG&E currently trails existing industry practices for technology deployment; the proposed project is designed to close that gap.

Technology projects often serve an important role in improving work efficiency in complex work environments. The IT projects classified as system safety related are not necessarily able to mitigate a safety risk by themselves. Rather they are technology enablers associated with another safety project addressed in Exhibit 4. Together with the associated safety project they contribute to improving system safety.

b. Specific Initiatives

Emergency Response Technologies

PG&E classifies its emergency response technologies as lagging the industry. Rapid response to outages and unsafe conditions comprises a necessary activity for electric utilities. In particular for PG&E, the percentage of downed energized conductors that occur (36 percent) makes rapid response essential. The most critical improvement in this initiative is the addition of an Automated Crew Callout tool, which is becoming a standard feature in the industry. Rather than manual telephone dialing, these systems automate the callout operations. They provide the ability to assemble a line crew for outage response more quickly. Where downed conductors remain energized, first responders cannot begin their work until the lines have been disconnected and grounded. The number of fatalities that PG&E has experienced makes this enhancement a material contributor to system safety, in both Liberty's and PG&E's judgment.

Data Historian

The current, legacy PG&E data historian system lags the industry. This initiative will replace it with a commercial, industry-standard software system. The data historian will need to be increased to keep up with the increased SCADA functionality, which mitigates a large safety risk. These systems record time-stamped data for analysis of events.

Outage Reporting and Analysis

Liberty classifies the outage reporting and analysis system as a safety related initiative. PG&E did not classify it as a safety initiative in its response to Liberty. However, PG&E did mention the system safety benefits of the initiative in their work papers. Liberty also considers the current tool to be dysfunctional, rather than just behind the industry. PG&E currently uses legacy tools and manual processes to produce simple outage reports. The new system under development will increase automation significantly and it will interact with other IT systems such as SCADA, Distribution Management System (DMS) and GIS. PG&E is currently implementing the new system. The GRC contains expenditures in 2014 to complete the implementation.

The limited functionality of the current outage reporting system hinders system safety improvement. In a simple request for conductor failures by wire size for years other than 2010, PG&E gave the following response:

> *Regarding conductor failures by wire size, PG&E's OUTAGE database does not currently track this information and therefore the failure data is not readily available. The data used to produce 2010 information involved an engineer working many weeks to manually research each outage, identify the exact fault location, and consult PG&E's load flow model to determine conductor size.*

SCADA Platform Upgrade

PG&E classifies its SCADA platform upgrade as a new initiative. This initiative addresses how SCADA information (such as status and operating data) is gathered and displayed for the system operators. As the number of SCADA devices grows, associated hardware and support must also grow. A portion of this initiative addresses hardware items, such as servers and processors. Another portion centralizes the SCADA network operations. One important upgrade to keep up with industry technology trends is the capability to incorporate IP-based (Internet Protocol) devices. Many of the field devices are now migrating to IP-based communications. This initiative adds this capability.

Electric Distribution GIS

This initiative is the most costly of the group. It has been underway for several years. The funds in the GRC will complete the majority of this new system in 2014. The lack of a functional asset registry system was a major finding mentioned in the IRP report. PG&E classifies this system as being behind the industry. Liberty considers it to be dysfunctional.

The current mapping system GEMS (Gas and Electric Mapping System) is strictly image-based. PG&E has built no asset intelligence into it. SAP houses the asset information. A third electrical connectivity system must also be used to manage the system. The new GIS system integrates these data systems into one, in order to support mobile technologies, system modeling, reporting and analysis, and overall asset management.

Asset Risk Based Maintenance

PG&E substations and the underground network have a separate CBM (Condition Based Maintenance) monitoring system and software tool. The system is already integrated with the SAP asset and maintenance registry. This initiative will integrate the data with more IT systems such as SCADA, DMS (Distribution Management System) and SAP work management systems.

Asset Risk Management Tool

This tool is conceptual at this stage. It will eventually include a software tool that can use inputs from the new technology systems being implemented to focus on the localized factors affecting system safety. The tool as envisioned will provide an integrated asset risk analysis tool for work planners and asset managers.

Mapping and Records

Many of the mapping records at PG&E are paper-based. The IRP report contained specific recommendations on improving the asset records at PG&E. This initiative is a part of implementing those recommendations. Electronic record conversions are included in this initiative. Most of these records are substation records. It also includes a field asset inventory of the overhead and underground distribution system, which is a critical part of implementing the new GIS system.

c. Justification

As we proceed through each category of distribution safety and security initiatives, we will in this section answer the following questions:

- Were they supported by structured risk assessments
- Did the GRC filing support them with costs benefit analysis

- Will they mitigate safety risks
- Can one determine the degree of mitigation?

We did not find the initiatives here to be derived from or supported by structured risk assessment. Moreover, the GRC does not lay a foundation for justifying them on a cost/benefit basis. We did conclude that the technology safety initiatives contribute to mitigating system safety risks in asset records, information management systems, and emergency response. Technology projects are increasingly important in improving work efficiency in today's complex work environment. Poor technology is frustrating to use. The management and monitoring of a widespread electrical grid without the use of proper technology would increase system safety risks. Overall, the initiatives improve system safety risk levels. The degree to which they do so cannot be determined from the GRC or from other information made available by PG&E.

6. Exhibit 4 – Chapter 5 - Electric Distribution Maintenance

a. Description

The table below lists the initiatives in this chapter along with Liberty's classification of each initiative.

GRC Exhibit 4 Distribution Maintenance Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Electric Distribution Maintenance	5	Patrols and Inspections	Exp	BF	$ 44,887	$40,755	$46,084	$46,286		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Enhanced wildfire patrols	Minimal $ included in Exp BF above							
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Overhead	Exp	KA	$ 41,083	$51,386	$52,455	$36,340		
Base Activity(Safety per PGE)	Electric Distribution Maintenance	5	Idle facilities investigations	Exp	KA		$ 1,831	$ 2,319	$ 3,819		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	PM & Repair - IR Inspections and Tags	Exp	KA			$ 6,600	$13,500		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Underground	Exp	KB	$ 18,354	$23,877	$24,853	$13,753		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	UG Barcode Enclosures	Exp	KB		$ 600	$ 1,000	$ 2,000		
Safety per PGE & Liberty	Electric Distribution Maintenance	5	UG Switch Replacement Program	Exp	KB		$ 1,000	$ 1,500	$ 1,500		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Network	Exp	KC	$ 7,930	$ 6,582	$ 6,193	$ 5,992		
Base Activity	Electric Distribution Maintenance	5	Maintenance of Other Equipment	Exp	BK	$ 2,353	$ 2,645	$ 2,713	$ 2,713		
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Overhead	Cap	2A	$ 93,980	$86,999	$85,062	$66,186	$58,246	$ 58,670
Safety per PGE & Liberty	Electric Distribution Maintenance	5	IR - Switch Replacement	Cap	2A			$ 750	$ 750	$ 450	$ 450
Safety per PGE & Liberty	Electric Distribution Maintenance	5	IR - Conductor Replacement	Cap	2A				$15,000	$30,000	$ 30,000
Base Activity(Safety per PGE)	Electric Distribution Maintenance	5	Idle facilities removal	Cap	2A		$ 6,450	$22,866	$26,550	$ 5,250	
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Underground	Cap	2B	$ 31,440	$28,588	$33,501	$23,416	$23,343	$ 23,526
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Underground Oil Switch Replacement	Cap	2B			$ 1,000	$25,000	$25,000	$ 25,000
Base Activity	Electric Distribution Maintenance	5	Preventive Maintenance and Equipment Repair-Network	Cap	2C	$ 203	$ 594	$ 1,110	$ 1,113	$ 1,050	$ 1,111
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Swivel oc manhole covers	Cap	2C	$ 3,640	$ 5,280	$ 4,500	$ 3,500	$ 3,500	$ 3,500
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network transformer replacement (high-rise & others)	Cap	2C	$ 6,381	$10,011	$ 6,193	$ 6,700	$ 5,400	$ 4,400
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network SCADA safety monitoring	Cap	2C	$ 8,236	$ 2,247	$ 5,056	$ 8,000	$ 7,500	$ 7,500
Safety per PGE & Liberty	Electric Distribution Maintenance	5	Network Condition-Based Maintenance	Cap	2C		$ 1,445	$ 1,000	$ 300	$ 75	$ 75

Liberty's classification of the idle-facilities initiative in terms of safety did not agree with the PG&E classification. PG&E classifies Idle Facilities Investigations and Removals as system safety initiatives. As is true for many other items in the patrol and inspect program, there exists a backlog of idle facilities that have been identified but never resolved. PG&E's database contains approximately 22,000 pending idle facility locations for review. PG&E felt that idle facilities can result in safety hazards, mitigatable through removal or de-energization. Liberty felt that no observed or defined safety risk differentiating these lines from other lines was apparent. GO rule 95 requires lines temporarily out of service to be inspected and maintained in conditions that will avoid hazards. It also common practice in the industry to disconnect and ground an idle tap line or transformer.

b. Specific Initiatives

<u>*Patrols and Inspection Program*</u>

The industry recognizes distribution line patrols and inspections as a main defense against system safety risks. The National Electrical Safety Code sets a performance requirement for inspection of lines and equipment. It states that, "Lines and equipment shall be inspected at such intervals as experience has shown to be *necessary*." Inspections are critical to identifying system hazards, such as broken guy wires, low hanging energized conductors, broken crossarms and insulators, and clearance issues created by third parties. Reliability benefits also result from line patrols. Underlying causes can be discovered and repaired before outages occur.

General Order 165 defines the California requirements for patrol schedules and inspection schedules. "Patrol" inspections consist of simple visual inspection of applicable utility equipment and structures, designed to identify apparent structural problems and hazards. Patrol inspections may be carried out in the course of other Company business. Patrols are required annually in urban areas (> 1,000 persons per square mile) and every other year in rural areas. Rural patrol inspections cycles increase to once per year in Extreme and Very High Fire Threat Zones in certain counties. PG&E generally uses "ride-bys" to conduct patrols. "Detailed" inspections are more focused than patrol inspections. Detailed inspections involve careful examination of individual pieces of equipment and structures, using visual means and use of routine diagnostic tests, as appropriate. Where practical and useful, they can also involve equipment opening and the rating and recording of certain conditions. Detailed inspections must be conducted every three years for general underground facilities. A five-year cycle applies to overhead facilities and pad-mounted transformers. PG&E conducts detailed inspections by walking. For both the patrols and inspections, PG&E uses a paper-based process for data-gathering. PG&E inspects the pad-mounted transformers on the three-year schedule used for other underground facilities; it does not rely on the five-year schedule allowed for them.

PG&E's Distribution Compliance Unit has design and ownership responsibility for preventative maintenance programs. The electric distribution maintenance program managers have responsibility for PG&E's distribution maintenance programs. These programs include overhead and underground distribution patrol and inspection program, line equipment testing, line equipment repair, line equipment replacement, infrared inspections on the underground system, insulator washing, corrective maintenance activities, wildfire mitigations, and streetlight repair and replacement. This responsibility includes managing program content, annual work planning, and budgeting. A field team provides direct support to each Division for GO 165 patrol, inspection, and equipment testing. Their role includes maintenance plan creation, modification, and support; patrol and inspection data capture and reporting; data analysis and support.

Prior to 2010 PG&E applied an up to 66 month deadline for completing repairs of items identified through inspection. In 2010, PG&E began implementing a new system for prioritizing notifications. The Company's objective was to complete newly identified notifications for abnormal conditions within 12 months, and to eliminate the backlog of repair items by the end of 2013. Under the previous prioritization system, PG&E could reassess notifications and extend deadlines. This approach produced a backlog of lower priority notifications.

The safety incident history listed in Section E.4 would indicate that the patrol and inspection program has been effective in minimizing system safety incidents due to causes preventable by inspection processes. Only one electrical contact incident (on March 11, 2009) was due to an observable defective situation. The main defective item found during the patrols and inspections has been failed wood crossarms. About 3,200 per year were found (2007 to 2011 data). Still, about 600 fail each year and cause outages. From a wood crossarm perspective, the program is about 84 percent effective (items proactively found divided by the total of items found and items that failed) in preventing failure. Similarly wood pole data is available. About 260 are proactively found each year, and 530 fail, for an effectiveness of 33 percent. Pending pole failures are more difficult to spot. Overall, about 33 percent of PG&E's primary voltage-level outages are due to equipment failure. This is an annual rate of 6.4 equipment outages per 100 miles. It was also noted that 32 percent of all system outages are logged as no cause found. We consider any unknown outage cause percentage over 10 percent to be high. Many of these outages could also be due to equipment failures.

This chapter also includes a modest safety initiative in the area of wildfire patrols. The Company proposes a new wildfire mitigation process for urban wildfire areas. PG&E patrols these areas annually. This initiative calls for patrolling on an early aggressive schedule, before the wildfire season starts. In addition, the overhead facilities in the areas would undergo an infrared inspection to identify any hot spots.

Infrared Programs – Switches, Connectors and Conductors

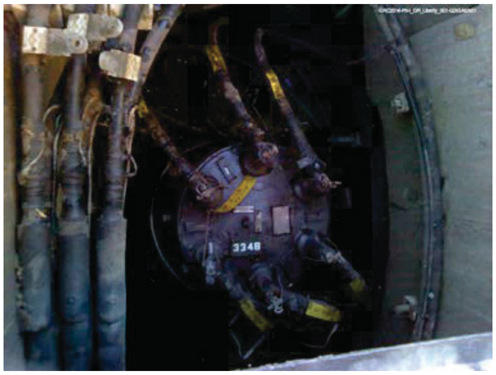
These safety initiatives contain an infrared program targeted at overhead distribution line switches and overhead conductor automatic splices. A typical automatic splice is shown in the cutaway view. It uses internal compression springs and tension jaws that grip the conductor. There have been a number of overhead splice failures on the PG&E system. A notable example was the splice failure at Candlestick Park on December 19, 2011. Internal corrosion in splices creates excessive electrical resistance. The splices fail as a result of excessive heating in the splice, resulting in mechanical failure. PG&E estimates that 600,000 to 800,000 auto splices exist on its system. In general, utilities are finding that these types of splices have lifespans less than the associated conductor lifespan, especially in coastal areas. Today's newer automatic splices include corrosion-resistant models.

PG&E has been conducting infrared inspections on a limited, as-needed basis. The Company now proposes an infrared inspection of the entire overhead distribution system on a two-year cycle, starting in 2013. This cycle would address about 50,000 circuit miles each year. PG&E estimates that it experiences 2,000 to 3,000 overhead conductor and splice failures annually, and projects a 10 percent outage avoidance from this program. This percentage amounts to about two hot spots every 73 miles, which illustrates the needle in the haystack problem that is so often found in searching for distribution problems. It is a common practice in the industry for utilities to infrared-inspect distribution systems on a cyclic basis. It is the best available means of identifying trouble-prone connectors.

This initiative includes several categories of expenditures. The total cost for the 2014 to 2016 period is $90.15 million. This sum includes the expense portion for only 2014. Holding the 2014 expenses constant for the 2015 to 2016 period would produce a total cost of $117.15 million for the three years. The expenditure categories are:

- *Infrared Inspection:* The portion of the program addressing scans by crews of all the circuits is an expense item. The crews will also repair some items as they are discovered. Mechanical sectionalizing switches and ganged air break switches are a common source of hot spots. If the switch jaws are not aligned properly, a hot spot will develop. Often the crew can fix the hot spot by switch adjustment. When a heated splice is found, it will be replaced by the crew. About $13.5 million per year or 34 percent of three-year program costs is forecasted for this category.
- *Switch Replacement:* Sometimes the switch contacts are burned and pitted, requiring switch replacement. About $1.65 million, or 1.4 percent, of three-year costs is forecasted for this category.
- *Conductor Replacement:* PG&E proposes to replace spans containing more than three splices. Most spans on the PG&E system use a three-phase configuration. If only one of the three wires in the span has three splices, then only one will be replaced. This replacement conductor would need to be the same wire size and type as the other two conductors to avoid sagging and clearance issues. Replacing a conductor would involve dead ending the conductor on each adjacent structure and installing two jumpers and four connectors. This program is based on single span replacement methods. About $75 million or 64 percent of the three-year costs is forecasted for this category.

Underground Oil Switch Replacement



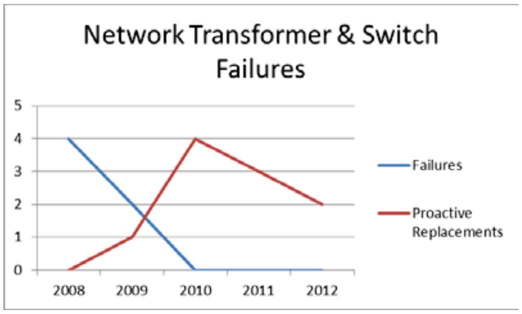
The proposed oil switch replacement program in this GRC Exhibit 4 chapter is separate from the TGRAM/TGRAL switch program addressed in PG&E Exhibit 4 Chapter 16. The oil switches in the Exhibit 4 Chapter 16 program are commonly located in underground manholes and transformer vaults (see adjacent picture). PG&E's system includes 20,378 of these switches. These types of underground switches are common in the industry. Since 2000 the PG&E switches have experienced 259 failures with 61 involving explosion and fire risk. Thirty seven of these 61 failures involved 1970s or 1980s vintage switches. PG&E estimates about 2,500 switches are older than 1970 vintage.

A thorough assessment will need to occur before replacements can be targeted. PG&E proposes inspection and assessment activity from 2012 through 2014, with replacements occurring primarily in 2014 through 2016. The condition based assessment would include oil level, age, type, switching configuration, corrosion, operator control, location factors, lack of an oil sight glass, and vendor/model data. PG&E started the assessments in 2012. PG&E estimates that almost 90 percent of the assessments will be complete by March 2013. The proposal forecasts replacing 1,500 switches from 2014 through 2016. PG&E estimates that two failures per year will be avoided.

PG&E also proposes to install barcode tags on about 402,000 underground enclosures. Barcode installation would occur in conjunction with normal routine inspections. Barcoding will be useful with the future mobile technology. It is common in the industry to have field barcodes for major maintenance items.

Networks

A serious injury occurred in 2005 to a member of the public due to a network incident. Hot gases from a network vault manhole explosion were released. Prior to this time the general maintenance plans for the networks, apart from the required inspections, used a "run-to-failure" approach." As a result of this incident, PG&E developed and implemented a comprehensive network asset maintenance plan in 2008.



PG&E has twelve networks, all of which lie in the Bay area. A total of 67 primary distribution network feeders serve 1,366 network transformers. Peak network load is 440 MW. PG&E has used the SAP asset registry for the networks since 2008. Failure data has only been kept since inception of the new Asset Management program in 2008.

The network program has been successful in reducing network transformer and switch failures. Proactive maintenance replacements have been accompanied by a drop in the number of failures to zero.

Oil sampling forms the core of a sound asset management for this equipment. PG&E started oil sampling in 2008. The analysis of the dissolved gases in the oil sample comprises the basis for transformer and network protector replacement decisions. PG&E annually takes an oil sample from all oil-filled transformer chambers. The results of this testing drives scheduling of equipment for replacement. Transformer replacement decisions rely solely on gas analysis results. PG&E does not apply any age-based criteria. Protectors are now replaced at the same time as the transformer. Absent an emergency, PG&E schedules replacement for the next year. The network protector is an air insulated circuit breaker and does not contain oil.

A maintenance program also addresses the protectors. PG&E replaced many transformers in the 1980s, but did not address the associated protectors. Protectors have a 35 year life, but some date from the 1940s and 1950s. PG&E started a 100 percent internal inspection program in 2008. Workers access the inside of each protector to clean the switch mechanism, and to check contacts, relay settings, and other items. The Company uses a three year inspection cycle.

Some network transformers and protectors are located in high-rise buildings. These units pose a significant system safety risk. Risks of transformer explosion or fire in a high-rise building have substantially higher impact potentials than what applies for street-level, underground vaults. The risks of installing oil-filled transformers in high-rise buildings are no longer tolerable. Common industry practice is to install dry-type, rather than oil-filled transformers inside buildings. Failures of oil-filled transformers as they age can generate several types of hazardous, explosive gasses, including methane, hydrogen, and acetylene. PG&E has had 91 high-rise network transformers in service. Twenty five of these transformers have been replaced with dry-type units. Sixty six of these ninety-one units remain to be replaced. Using preferred dry-type transformer replacements will eliminate explosion and fire hazards. Where existing transformer rooms prove too small for dry-type units, PG&E will install single chamber units employing explosion-resistant casing. This safety initiative proposes to replace all of the remaining high-rise transformers by 2016.

PG&E proposes the use of a network CBM (Condition-Based Maintenance) system as a safety initiative. The Network inspection approach used in 2008 involved a paper process checklist followed by input into an Excel sheet. Starting in mid-2011 PG&E automated the network maintenance records into CBM (a software program using tablet PCs). Current activities involve the addition of oil analysis results. Minor levels of 2014 expenditures are proposed to complete the system additions.

PG&E also proposes a safety initiative in this exhibit chapter for the network SCADA system. PG&E's 1980s vintage network SCADA system offered some basic functionality (secondary amps, open/close, and overload alarms). It operates strictly as a monitoring system with no supervisory control. PG&E decided to upgrade the system in 2009, as part of a process to move from time-based maintenance to true condition-based maintenance. The new system can monitor more functions (*e.g.*, temperature and pressure on each oil filled chamber and oil level). It also offers some remote supervisory control capability (*e.g.*, remote protector open/close and group feeder trip function). PG&E replaced one of its 12 SCADA networks in 2012, and has scheduled a second for replacement in 2013. The Company proposed to complete all network SCADA replacements by 2017.

<u>*Swiveloc Manhole Covers*</u>

Another safety initiative addressed in GRC Exhibit 4 calls for installation of Swiveloc manhole covers. They will serve as the last "line of defense" for manhole explosions. Manhole covers weigh 200 pounds, but can still be tossed several hundred feet during an explosion. Manholes located below street grade often accumulate explosive gases, such as gasoline vapors. Cable failures can cause explosive manhole gases to ignite. PG&E experienced 15 failure incidents in 2011. Three involved explosions and manhole cover displacement. Fourteen more such incidents occurred in 2012. Three of them involved explosions and manhole cover displacement. PG&E also suffered a 2005 electric injury incident that involved manhole explosive gases.

The Swiveloc cover is designed to remain engaged to the manhole frame throughout all but the most severe explosive events. Utilities across the country now use this type of manhole cover in many major metropolitan areas. San Francisco alone has 8,800 manhole covers. PG&E installs the covers in networks and in other locations having high pedestrian traffic. The Company must mill out the manhole concrete neck to install these new covers. The Company then chains the new manhole cover frame, and bolts it to the manhole structure.

PG&E has installed these covers along parade routes and downtown San Francisco festivity areas. PG&E also installed the covers in Union Square area and Chinatown. They are proposing to install 1,800 Swiveloc manhole cover replacements from 2014 to 2016.

c. Justification

Again, we found that the GRC initiatives of Exhibit 4, Chapter 5 were not supported by structured risk assessment or justified by analyses of their costs and benefits. However, with one exception, we found them to be sound programs that appear to be effective and properly managed programs that mitigate identified safety risks.

We found PG&E's preventive maintenance patrol and inspection program to comprise a base activity that the Company has effectively managed. The industry recognizes distribution line patrols and inspections as a primary defense against certain system safety risks. PG&E has a good track record. Since 2004, PG&E has experienced only one electric contact incident from a defective condition that should have been observable during a line patrol. Liberty did not observe any apparent safety risk gaps in this program. PG&E inspection schedules have met or exceeded the inspection timeline requirements of GO Rule 95. Liberty observed, however, that PG&E recorded 32 percent of system outages as unknown, which is high (over 10 percent). This percentage needs to be reduced in order to improve their failure data. This data collection issue underscores the importance to risk assessment of assuring that data about system conditions and events is carefully collected and maintained.

We concluded that the enhanced wildfire patrol program contributes to improving system safety by attempting to reduce wildfire ignitions. The initiative described in the current GRC comprises a moderate process improvement that will contribute to identifying possible equipment hot spots before the start of the wildfire season. Precise contributions to wildfire reduction cannot be quantified. Liberty believes, however, that the impact on wildfire reduction will be minor.

We found that the infrared inspection program contributes to system safety by reducing wires down; it also contributes to improving reliability by identifying heated switches. Overhead energized wires down comprise risk factors for both wildfires and system safety. They also form a major cause of outages.

We also found that the underground oil switch replacement program contributes to system safety by reducing explosion and fire risk. Sixty-one incidents of explosions and fires involving these oil switches have occurred since 2000. One employee injury occurred in 2012. These pre-1970 vintage switches have exceeded their operating lives.

We found the underground enclosure barcode program to be an effective contributor to employee and system safety, by simplifying field data access. This proposal represents a minor initiative to install barcode tags on underground enclosures. It is common in the industry to have field barcode for major maintenance items. Street manhole systems and sidewalk vaults are difficult and dangerous to access. This initiative improves safety by assuring the crew is at the correct location before they begin work activity to set up a safety zone and enter the underground facility.

We found that PG&E's network high-rise transformer replacement program mitigates a high consequence safety risk. Network transformers and protectors located in high-rise buildings pose a significant system safety risk. The risk of installing an oil-filled transformer in a high-rise building is no longer considered tolerable. Oil filled transformers are subject to generating several types of hazardous gasses that are highly explosive.

We found that the network CBM program contributes to system safety by improving the asset registry. In mid-2011 PG&E automated the network maintenance records into CBM (a software program using tablet PCs). PG&E has already completed the vast majority of the work. This initiative involves minor expenditure in 2014 to complete the system additions.

We found that the network SCADA program contributes to system safety by improving system monitoring and control. PG&E installed the existing network SCADA system in the 1980s. In addition to maintenance problems, the existing system has operational limitations. The system's monitoring functions are minimal. The new SCADA system will improve the monitoring capabilities in areas critical to system safety (*e.g.*, transformer temperature and internal pressure).

The Swiveloc manhole replacement program contributes to system safety by eliminating the hazard of ejected manhole covers. PG&E installs these covers in networks and other locations with high pedestrian traffic.

The exception to our conclusions that the initiatives of Exhibit 4, Chapter 5 represent effective measures involves conductor replacement under the infrared program. Portions of that replacement program compete with rather than complement the conductor replacement in Exhibit 4 Chapter 15 (addressed below).

7. Exhibit 4 – Chapters 6-8 – Pole Test/ Replacement and Vegetation

a. Description

The next table lists the initiatives in these chapters along with Liberty's classification of each initiative.

GRC Exhibit 4 Pole Test/Replacement and Vegetation Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Pole Test & Treat, Joint Utilities	6	Poles-Inventory/Test & Treat	Exp	GA	$ 6,550	$ 16,184	$ 19,251	$ 16,117		
Base Activity	Pole Replacement	7	E Dist Inst/Repl OH Poles	Cap	07	$ 89,113	$135,706	$153,498	$ 69,578	$67,912	$61,103
Base Activity(Safety per PGE)	Pole Replacement	7	Replace centerbore street light poles	Cap	07		$ 19,998	$ 6,300			
Base Activity	Vegetation Management	8	Routine Tree Work	Exp	HN	$151,600	$151,400	$153,200	$156,000		
Base Activity	Vegetation Management	8	Vegetation Control	Exp	HN	$ 8,400	$ 8,500	$ 8,600	$ 8,700		
Base Activity	Vegetation Management	8	Quality Assurance	Exp	HN	$ 900	$ 1,100	$ 1,200	$ 1,200		
Base Activity	Vegetation Management	8	Public Education	Exp	HN	$ 400	$ 400	$ 400			
Base Activity	Vegetation Management	8	Environmental Compliance	Exp	HN	$ 300	$ 300	$ 12,700	$ 12,600		
Safety per PGE & Liberty	Vegetation Management	8	Fire Risk Reduction	Exp	HN				$ 11,100		
Base Activity	Vegetation Management	8	Vegetation Management Balancing Account	Not included in this spreadsheet							

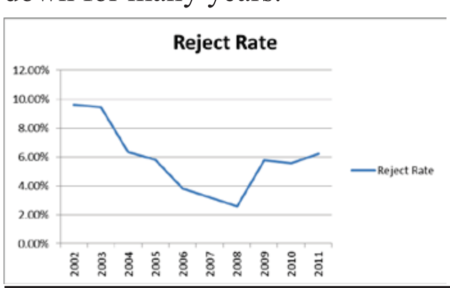
Center-bore poles are hollow core wood street light poles; they are subject to lifespans shorter than the average for solid wood poles. PG&E classifies its center-bore streetlight pole replacement program as a safety initiative. Liberty agrees that these decayed poles create safety risk; however, the Company expects to complete replacement expenditures by 2013, before the GRC rate period.

b. Specific Initiatives

Wood Pole Program – Testing & Replacement

PG&E has approximately 2.3 million wood poles on its system. Wood distribution poles comprise the structural heart of the electric distribution system. This critical system component bears close scrutiny. Liberty has reviewed the safety aspects of the wood pole program. Nevertheless, we consider the sustainability aspects by far the overriding concern when developing wood pole programs. The large safety factors built into the system generally mean that wood pool facilities will fall substantially behind the sustainability curve long before serious safety concerns occur. In other words, treatment and replacement should already be occurring before facilities begin to raise substantial safety concerns.

PG&E begins on a comparatively strong footing in addressing its wood poles. The species in service on its system include two of the most durable types (Western Cedar and Douglas fir). Moreover, their average age of 39 years is comparatively long. These factors will help hold costs down for many years.



PG&E has conducted a groundline pole testing and treatment program since 1995. The program is well into its second cycle. The 10-year cycle length is typical in the industry.

The accompanying graph shows a declining reject rate. One would expect a lower reject rate during the second inspection cycle. However, the graph could be somewhat misleading as PG&E inspects poles by geographical area. The reject rates in the geographical areas vary according to the installation history and climatic characteristics of each area.

PG&E's pole inspection and groundline treatment processes follow industry-standard guidelines. Crews perform a visual inspection from top to ground, and conduct a sound test on all poles. A partial groundline excavation occurs for all poles ten years old or greater (with the exception of Douglas fir and Western Cedar penta poles that are less than fifty years old if they have not previously been intrusively tested). PG&E performs external decay checks and, as necessary, full groundline excavations. All poles ten years old or greater are subject to internal bore and probe inspection. Rejected poles undergo a strength calculation that is done to determine they are either acceptable for further service based on standard safety factors, or unserviceable. PG&E reinforces or replaces unserviceable poles. Crews apply preservatives if the pole is to remain in service or be reinforced. PG&E does not currently have a maximum pole age limit for any type of pole.

There have been some concerns and changes to the program recently.

- PG&E added strength calculations in 2011. This feature allows for serviceable poles to remain in service for at least one more cycle.
- Prior to 2010, the local offices entered pole replacement notifications in the SAP system. Not all of the poles recommended for replacement under the test and treat program were replaced. Now the pole test program automatically generates a replacement notification in SAP that can be tracked.
- The pole testing program has fallen behind schedule. More poles are now being tested in order to catch up by 2015.
- A pole replacement backlog has developed. The old prioritization system permitted pole replacement notifications to have completion durations of up to 66 months. PG&E could reassess notifications and extend deadlines, thus creating a backlog of lower priority notifications. In 2010, PG&E began implementing a new system for prioritizing notifications. PG&E's new prioritization system classifies work identified prior to

January 2010 as backlog. PG&E plans to complete all new notification work within 12 months, which would avoid creation of any additional backlog. PG&E forecasts to eliminate the backlog by the end of 2013.

After elimination of the pole backlog, the GRC forecast assumes about 4,870 pole replacements per year under the test and treat program. PG&E identifies and replaces another 500 poles per year under its line inspection program. These two replacement sources amount to about 0.24 percent of the total population, which is not sufficient to produce a sustainable rate. Apart from its pole inspection program, PG&E replaces additional poles as lines are relocated or rebuilt. PG&E has purchased an average of 21,168 poles each year over the past ten years. This amount equates to 0.96 percent of the population.

Liberty reviewed the pole failure rate for the past five years, examining outage data. We found no significant concerns. Failure-causing outages during non-storm days run from 2.0 to 2.4 percent of total outages (not including transformer outages). The rates increase to the five percent range on major storm days. This level of increase is within reasonable expectations.

Vegetation Management

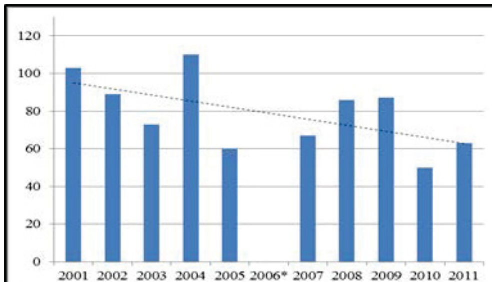
PG&E classifies wildfires as an enterprise-level risk. The vegetation management (VM) program plays a central role in managing wildfire risk. This risk in California has been a concern long before the PG&E ERM program began. About sixteen years ago PG&E's VM program was consistent with basic industry standard. Vegetation Management performed trimming on a time and material basis under cycles ranging from three to five years. Prompted by lawsuits on fires and by environmental and property damage, PG&E began an annual trim and patrol program. This program can best be described as "just in time" trimming. Rather than using a time and materials approach, PG&E moved to a trim-unit cost program. Liberty considers such unit contracts a sound method for understanding and controlling vegetation trimming costs.

The same, single work group at PG&E manages both transmission and distribution vegetation programs. A Planning group handles contract administration, quality assurance, database, billing, and customer outreach. An Operations group handles field management, organized into eight trim areas. Each area employs two foresters.

California has a number of different fire areas, with each subject to differing minimum trim standards and other regulations, including state/federal fire areas, local fire areas, FRAP areas (Fire and Resource Assessment Program), and Urban Wildland Fire (UWF) areas (PG&E-defined geographic areas that meet specific criteria of population density, ground slope, and the CAL FIRE definition of Extreme or Very High Fire Threat). PG&E's standard trimming meets the regulations in all areas. PG&E does not allow any drop below standards from one area to another.

A unit-trim contracting process allows PG&E to dictate the exact trimming for each tree. Trimming is done by circuits. PG&E pre-inspects 100 percent of the overhead power lines each year. Handheld devices enter the collected trim data. About four to six weeks after the pre-inspect work the tree contractor performs the actual trimming. Contractors trim about 1.3 million trees each year. A quality control sampling process exists. Moreover, a quality assurance audit process provides for a more detailed work review. PG&E also investigates every vegetation outage which occurs (about 4,000 per year for non-major storm days).

The annual patrol and trim program keeps vegetation reliability indices at low (strong) levels. More importantly from a wildfire safety perspective, the vegetation-cause ignition events have shown a steady decline, as the accompanying graph shows.



* From 2001 to 2005, the number of CPUC reportable vegetation incidents was collected by the Electric Incident Reporting group. CPUC decision 06-04-055 eliminated the requirement for reporting vegetation-related incidents in April 2006, and the Eclectic Incident Reporting group stopped collecting this data So, 2006 was a partial year, and it is shown as blank. Beginning in 2007, the Vegetation Management group began collecting this data consistent with the prior Electric Incident Report group approach.

<u>*Vegetation Management – Fire Risk Reduction*</u>

As demonstrated in the ERM Wildfire Mitigation Plans over the years and with the on-going CPUC rulemaking process in this area, mitigating wildfires has been a continuous improvement process. PG&E has a safety initiative titled Fire Risk Reduction in this exhibit chapter arising from the mitigation plan. For the highest one percent risk areas, PG&E proposes to inspect danger trees adjacent to the circuits over a five-year period. The ANSI A300 (Part 7) Integrated Vegetation Management standard defines a danger tree as "a tree on or off the right-of-way that could contact electric supply lines" and a hazard tree as "a structurally unsound tree that could strike a target when it falls" (in this case, the target is the utility line).

It is common practice to remove hazard trees on distribution line rights-of-way, but not danger trees. Contractors will inspect each danger tree, check it for internal decay, and remove it if necessary. Danger trees that fail this inspection are classified as a hazard tree, and removed. Often a hazard tree is not readily apparent without a detailed investigation using sonic or intrusive bore tests.

c. Justification

Again, we did not find the initiatives of GRCV Exhibit 4, Chapters 6-8 to be driven by structured risk assessment or cost/benefit analysis, but they generally represent appropriate and effectively managed responses to underlying safety issues.

We found that the wood pole program operates as a base activity that PG&E manages effectively; no unaddressed safety risk is apparent. Wood poles comprise an important structural element of the electric distribution system. Liberty reviewed the program structure and components to verify that there were no apparent gaps in identifying and addressing safety risks. The Liberty review did not include field observations.

We also found that the vegetation management program comprises a base activity that PG&E operates effectively to minimize wildfire risks. The PG&E vegetation management program comprises an important part of the enterprise-level wildfire risk management. PG&E has a comparatively very strong program in place. Liberty reviewed the program to verify that there were no apparent gaps in identifying and addressing safety risks. The Liberty review did not include field observations.

We found that the fire risk reduction program could potentially reduce wildfire risk. This initiative consists of an aggressive tree inspection and removal program for high fire-risk areas. Many outages are caused by tree and branch failures originating from outside the rights-of-way. This PG&E program focuses on hazard tree abatement, or tree risk management.

8. Exhibit 4 – Chapters 13 to 15 – Substation Assets, Planning & Reliability

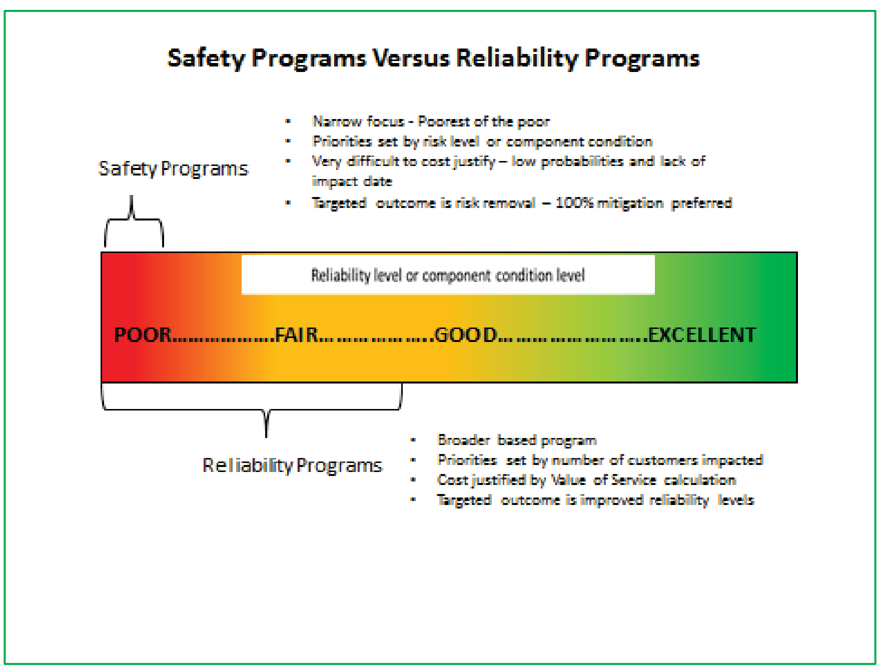
a. Description

The next table lists the initiatives in these chapters and Liberty's classification of each initiative.

CRG Exhibit 4 Substation Assets, Planning & Reliability Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Substation Asset Strategy	13	Dist Sub: Maintain & Operate	Exp	GC	$ 33,077	$ 37,572	$ 40,064	$ 40,064		
Base Activity	Substation Asset Strategy	13	E Dist Subst Repl Other Equip	Cap	48	$ 10,889	$ 9,030	$ 13,818	$ 14,059	$ 12,622	$ 13,528
Base Activity	Substation Asset Strategy	13	Switchgear Replacement	Cap	48	$ 28,125	$ 34,377	$ 33,588	$ 42,962	$ 51,500	$ 71,950
Base Activity	Substation Asset Strategy	13	Breaker Replacement	Cap	48	$ 10,165	$ 6,994	$ 7,500	$ 9,000	$ 10,500	$ 12,000
Base Activity	Substation Asset Strategy	13	E Dist Subst Repl Transformer	Cap	54	$ 44,895	$ 61,062	$ 39,051	$ 58,554	$ 53,291	$ 49,414
Base Activity	Substation Asset Strategy	13	4 kV Bank Replacement	Cap	54	$ 1,243	$ 1,267	$ 2,100	$ 6,300	$ 6,900	$ 6,300
Base Activity	Substation Asset Strategy	13	E Dist Repl Substation - Safety	Cap	58	$ 1,152	$ 875	$ 3,138	$ 3,126	$ 3,120	$ 3,110
Base Activity	Substation Asset Strategy	13	E Dist Subst Emergency Replace	Cap	59	$ 40,942	$ 27,342	$ 41,153	$ 41,011	$ 40,940	$ 41,118
Base Activity	Elect Eng – Dist Planning, Ops,	14	Opr Distribution Sys - El Eng	Exp	FZ	$ 19,603	$ 22,077	$ 23,187	$ 23,392		
Safety per PGE & Liberty	Elect Eng – Dist Planning, Ops,	14	Wire down investigations	Minimal $ included in Exp FZ above							
Base Activity	Electric Distribution Reliability	15	Base Reliability Program	Cap	08	$ 4,001	$ 3,500	$ 4,500	$ 9,580	$ 9,470	$ 10,120
Safety per PGE & Liberty	Electric Distribution Reliability	15	Overhead Conductor Replacement Program	Cap	08	$ 5,929	$ 9,190	$ 8,000	$ 32,500	$ 34,130	$ 34,509
Base Activity	Electric Distribution Reliability	15	Line Recloser Revolving Stock	Cap	08	$ 10,736	$ 8,875	$ 12,000	$ 24,420	$ 24,530	$ 25,080
Reliability	Electric Distribution Reliability	15	CORNERSTONE Rural Fuses	Cap	08	$ 37,029	$ 1,750				
Reliability	Electric Distribution Reliability	15	CORNERSTONE Rural Line Reclosers	Cap	08	$ 24,687	$ 15,072				
Reliability	Electric Distribution Reliability	15	CORNERSTONE Circuit Automation & Interconnectivity (	Cap	08	$ 3,952	$ 64,500	$ 106,050			
Reliability	Electric Distribution Reliability	15	Escalation	Cap	08			$ 705	$ 1,686	$ 1,610	$ 1,947
Reliability	Electric Distribution Reliability	15	FLISR Systems	Cap	49				$ 60,000	$ 60,000	$ 60,000
Reliability	Electric Distribution Reliability	15	Targeted Circuit Initiative	Cap	49	$ 57,259	$ 52,128	$ 52,000	$ 26,000	$ 26,000	$ 26,000
Reliability	Electric Distribution Reliability	15	Recloser Control Upgrades	Cap	49	$ 2,363	$ 2,024	$ 800	$ 1,600	$ 2,400	$ 2,400
Reliability	Electric Distribution Reliability	15	Overhead Protection	Cap	49	$ 6,204	$ 1,796	$ 3,100	$ 6,000	$ 6,000	$ 6,750
Reliability	Electric Distribution Reliability	15	Underground Protection	Cap	49	$ 2,298	$ 2,015	$ 1,600	$ 2,400	$ 2,400	$ 3,200
Reliability	Electric Distribution Reliability	15	Fault Indicators, Overhead and Underground	Cap	49	$ 2,944	$ 1,944	$ 2,500	$ 5,250	$ 5,462	$ 6,284
Reliability	Electric Distribution Reliability	15	Escalation	Cap	49			$ 1,719	$ 2,590	$ 2,459	$ 2,918

Except for the overhead conductor replacement program, the reliability initiatives were not classified as safety initiatives by Liberty or by PG&E. The Company observes a strong relationship between reliability and safety. Initiatives including PG&E's targeted circuit initiative (Exhibit (PG&E-4), Chapter 15, p. 15-21) and Fault Location, Isolation and Service Restoration (FLISR) projects (Exhibit (PG&E-4), Chapter 15, p. 15-20) seek primarily to improve reliability; however, they also provide safety benefits. PG&E proposes such projects primarily from a reliability perspective (which is how utilities undertaking similar activities generally justify



them); therefore Liberty does not treat them as system safety initiatives.

The CPUC released a Value of Service Study in May 2012. This study contains a system for ranking all reliability projects according to their improvement value to customers. This study was released too late for PG&E to use it in ranking items proposed in the GRC. PG&E did use the Value of Service ranking at the workpaper stage to validate its existing programs. This exercise showed the programs to be valid from the Value of Service perspective.

Liberty excluded reliability-targeted programs from the list of system-safety measures we examined. Improving a safety condition will very often benefit reliability. Reliability improvements will less often benefit safety. Outages that utilities, including PG&E, can avoid affect public or community safety (keeping people safe in general). These programs are classified as reliability programs. Safety programs focus on improvements targeted primarily to address system safety (correcting system conditions that cause hazards. The graphic above illustrates how safety and reliability programs further relate to each other.

b. Specific Initiatives

Substation Asset Strategy

Both Liberty and PG&E classified the items in Chapter 13 as Base Activities. PG&E is executing the base activity programs in a manner that makes no unaddressed safety risk apparent. Section C.4 notes that PG&E's forecast includes several substation transformer and switchgear replacement projects. While safety related, PG&E did not classify these expenditures in this response as addressing an identified risk. PG&E considers these projects as base-level activity, even though the absolute value of the expenditure forecast can vary from year to year depending on the complexity and timing of specific projects.

Liberty reviewed the substation distribution switchgear replacement program and the substation distribution breaker program. Certainly, failure to maintain or upgrade these breakers and switchgear could increase system safety risks. The PG&E asset management plan in place for these components mitigates risks. Liberty feels that the assets have been properly assessed and that a suitable strategic maintenance plan exists. The maintenance plan addresses both yearly maintenance and long-term replacement needs.

Overhead Conductor Replacement Program

The large amount of small obsolete conductors on PG&E's system reflects legacy conditions, which Section A.3 discusses. The issue rises to the level of serious safety concern. PG&E has 113,000 circuit miles of primary distribution conductor. Number 6 copper (#6 Cu) conductor comprises 22,206 miles (19.6 percent) of this total mileage. The industry formerly made widespread use of this #6 copper conductor, but now recognizes it as obsolete, due to its small size. The small conductor size makes it subject to greater breaking as it ages. Over many years of service, conductors will experience numerous situations of arcing together, due to high winds or lightning strikes. These occurrences cause small pits in the conductor. More robust larger conductor sizes better withstand this type of pitting without losing a material amount of strength.

Small copper wire also anneals at lower faults current levels than does larger conductor. Annealed copper becomes brittle and loses strength. Some utilities have safety rules precluding work on energized conductors this small, because of the high potential for breakage. In the past, PG&E conducted pull strength tests on #6 Cu conductors before scheduling replacement. The Company discontinued this after all of the conductors showed low strength. Past test results show conductors testing at around 65 percent of rated strength.

In addition to the #6 Cu, the PG&E system has 47,542 miles (41.9 percent of the 113,000 circuit miles of total primary conductor) of #4 ACSR conductors. The ACSR conductor has a steel reinforcement core. This type of conductor raises concerns due to its small size and to its bimetallic construction. The risk of bimetallic corrosion between the aluminum and the zinc on the steel core makes ACSR conductor not a good choice along coastal areas. Any deteriorated conductor section may be replaced under this program; however, the #6 Cu conductors are the primary concern. The analysis of 2010 outage data for conductor failure frequency shows one outage for every 102 miles of #4 ACSR conductors and one outage for every 59 miles of #6 Cu conductors. PG&E still purchases both the #6 Cu conductors and the #4 ACSR conductors.

A "wires-down" process, initiated in April 2012 consumes a minor portion of the costs of this program. PG&E implemented this forensic data-gathering process in conjunction with a Wire Down metric performance indicator. PG&E records the information gathered during the wire down investigation process using Microsoft Excel. The program seeks to identify causes. The information gathered also includes conductor attributes (*e.g.*, size, type, span lengths, number of existing splices) and pole construction and site related data (*e.g.*, framing, corrosion area, snow area). PG&E also records potential corrective recommendations and other comments. The wire down investigation process currently excludes: (a) third party initiated events (*e.g.*, vehicle contact, gunshot, and metallic balloons), (b) events that occur during a classified Major Event Day as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard 1366, and (c) older events not initially classified as a wire down event. All events initiated by vegetation contact are investigated by an employee of PG&E's Vegetation Management department. Based on Vegetation Management's recommendation, an engineer may also visit the site for a follow-up investigation.

The results of the wires down investigations indicated that a large percentage of downed conductors remained energized by the time that a PG&E Troubleman arrived on the scene. Ground fault currents occur when a conductor contacts a grounded object. A substation ground relay, a line fuse, or a recloser must sense the current, and clear the fault. PG&E observed that 38 percent of 12 kV system conductors were remaining energized. The corresponding 21 kV system percentage was 21. This hazardous situation combined with the propensity for the #6 Cu conductors to become annealed and break more readily.

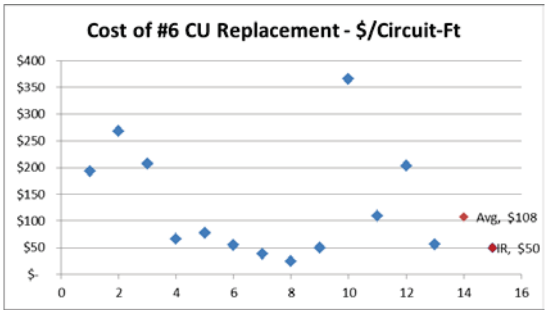
Liberty considers the percentage of downed energized conductors to be high. Benchmarking data is not readily available in the industry, but we have experience with some other utilities. We know of several major utility systems (23 kV) where downed energized conductors are estimated to be fractions of one percent. The main drivers for a high percentage of downed energized conductors could arise from a number of or a combination of factors (protection coordination practices, circuit grounding practices, transformer bank connections, and soil conditions among them). An outside consultant performed a distribution protection and coordination review for PG&E in 2012. The review verified that PG&E's protective coordination practices are superior and reflected what is currently considered good practice in the industry. PG&E is continuing to explore benchmarking data and circuit grounding practices, in order to obtain a better understanding of this issue.

PG&E determined the dollar amount of overhead conductor replacement work through the use of investment levels developed during the development of the overall system safety improvement plan. The Company used these forecasts, combined with historical costs from 2011 and 2012 overhead conductor replacement projects, to determine projected replacement amounts. PG&E uses a nominating process to identify the particular wire sections to be replaced in its planning processes. This process generates a list of projects. PG&E is developing tools to assist the planning areas with project identification. A software tool will use probability inputs (outage data, age, wire size, geography) and severity impacts (wire down history, number of customers, population density, wildfire risk) to rank the relative risk factor among their 155,000 protection zones. PG&E formerly called this tool the Risk Assessment Tool (RAT). It now uses the term System Tool for Asset Risk (STAR),

The GRC includes a plan to increase significantly the amount of overhead conductor being replaced from 2014 through 2016. PG&E proposed conductor replacement in the infrared inspections program (Chapter 5) and the overhead conductor replacement program (Chapter 15). The next table shows the total costs of these two programs and some associated data. In addition PG&E estimates that it will replace 250 miles of conductors in other programs, such as line capacity increases or new-business work.

Conductor Replacement Costs

Program Facet	Chapter 5 Conductor Replacement	Chapter 15 Conductor Replacement
Chapter Section	Electric Distribution Maintenance	Electric Distribution Reliability
2014 Forecast $ (000s)	$15,000	$32,500
2015 Forecast $ (000s)	$30,000	$34,130
2016 Forecast $ (000s)	$30,000	$34,509
Identification method	Infrared program	Planning area nomination process
Target conductor	Spans with three or more splices	Deteriorated or annealed conductor
Replacement method	Single span replacement	Multi-span replacement
Replacement $/Ft	$50	$108
Miles being replaced	113	62



We observed a cost per foot variance between the two programs. PG&E derived Exhibit 4 Chapter 15 costs by averaging the costs of various reconductoring projects. The scatter gram to the left shows the projects averaged. There is a wide variance in the costs per foot. The main factor in the variance was the size of the replacement conductor. Some of these projects involved replacements of a small conductor with a newer small conductor. Other projects involved betterment and upgrading to larger feeder conductor sizes. PG&E does not have a universally accepted replacement conductor in place for the #6 Cu or #4 ACSR conductors.

c. Justification

Again, we did not find risk assessments or cost/benefit analyses underlying the substation assets, planning & reliability initiatives addressed in GRC Exhibit 4 – Chapters 13 to 15. We did, however, find those programs to be contributors to mitigating safety risks, subject to several concerns.

We found the substation asset strategy programs to be effectively managed. Liberty believes that the assets have been properly assessed and that a strategic maintenance plan is in place. We observed no unaddressed safety risks.

We also found that the conductor replacement program addresses a serious safety issue. Its extent, however, is not reflected in this GRC. The impacts of conductor failures are magnified by the large percentage of downed energized conductors that remain energized. A recent fatality from these combinations occurred in 2012. This is a widespread safety concern which will take significantly more resources than those forecasted in this GRC to address.

We do not believe that Electric Operations has fully assessed the magnitude of the deteriorated conductor situation. The forecast levels for the Chapter 15 replacement did not grow from calculated needs based on a system assessment. Electric Operations has yet to fully assess the magnitude of the deteriorated conductor situation.

We found the unit costs of Chapter 15 conductor replacement to be high. The unit cost of replacement of $108 per circuit foot in Chapter 15 amounts to $570,000 per mile. Workpaper data indicates that replacement work can be done for around $50 per circuit foot, or $264,000 per mile. The main cost driver appears to be the lack of identification of a suitable replacement conductor. Many new aluminum alloy conductors (AAAC) now available have equivalent ampacity as the #6 Cu conductors and three to four times the breaking strength, and at an equivalent cost. Another factor in a high replacement cost is a lack of program controls. Rather than replace the conductors with equivalent ampacity wires, divisional engineers have installed upgraded feeder conductors, such as 4/0 aluminum. More effective program controls are in order.

PG&E's two different conductor replacement programs appear to compete with, rather than complement each other. Two reasonably aggressive programs are both "chasing the same prey." The Chapter 5 Maintenance conductor program looks for three splices in a span. These splices will generally only occur when the conductor has had past breaks. The Chapter 15 Reliability conductor replacement program is targeting conductors on the primary basis of outage history. This history also leads to conductors which have been often spliced. For small conductor replacement, it would be more appropriate to make the infrared and associated splice registry strictly an identification program rather than replacing conductor one span at a time.

9. Exhibit 4 – Chapter 16 – Underground Assets

a. Description

The next table lists the initiatives in this chapter and Liberty's classification of each initiative.

CRG Exhibit 4 Underground Assets Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety per PGE & Liberty	Underground Asset Managemer	16	Network Cable Replacement	Cap	56	$ 798	$ 7,000	$ 6,000	$ 21,000	$ 28,000	$ 28,000
Safety per PGE & Liberty	Underground Asset Managemer	16	TGRAM/TGRAL Switch Replacement	Cap	56	$ 20,881	$ 28,000	$ 22,400	$ 39,200	$ 39,200	$ 39,200
Safety per Liberty	Underground Asset Managemer	16	Tie-Cable Replacement	Cap	56	$ 1,814	$ 600	$ 200	$ 7,400	$ 6,800	$ 7,000
Reliability	Underground Asset Managemer	16	COE Cable Replacement	Cap	56	$ 15,647	$ 16,000	$ 16,000	$ 43,300	$ 41,200	$ 41,200
Reliability	Underground Asset Managemer	16	Reliability Related Cable Replacement	Cap	56	$ 16,681	$ 22,600	$ 20,600	$ 25,700	$ 26,300	$ 26,100
Reliability	Underground Asset Managemer	16	Escalation	Cap	56			$ 1,918	$ 3,478	$ 3,715	$ 4,293

b. Specific Initiatives

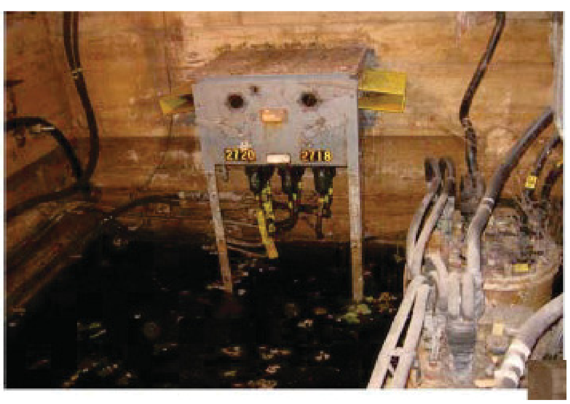
Network Cable Replacement

These primary voltage feeder cables and secondary cables lie within the San Francisco network. Twelve PG&E networks containing 69 primary feeders serving 1,366 transformers. PILC (Paper

Insulation/Lead Cover) comprises the bulk of the primary cable forecasted for replacement. These 1920 to 1960 vintage cables are reaching the end of their useful lives. Cable failures create risks of manhole explosion and fire when they fail. Manholes located below street grade often accumulate explosive gases (*e.g.*, gasoline vapors). Explosive gases in the manholes can ignite when cables fail. PG&E suffered fifteen failure incidents in 2011; three involved explosions and manhole cover displacement. The year 2012 witnessed 14 failure incidents; three involved explosions and manhole cover displacement. PG&E also experienced a 2005 electric-injury incident involving explosive manhole gases. These consistent failure incidents make addressing the risk an important safety initiative. The PG&E plan also forms part of a long range sustainability plan that has important reliability implications.

PG&E bases network feeder cable replacement prioritization on age, cable testing results, safety concerns, and circuit location. A VLF (very low frequency) cable insulation testing program exists. It is industry standard. PG&E's approach calls for replacing the entire feeder. A long-range asset management plan forecasts replacing all of the older PILC feeder cable by 2030. The Company forecasts eventual replacement of 60 of the 12 kV feeders. The current GRC replacement schedule includes 12 of these feeders. PG&E prioritizes the secondary cable replacements on the basis of their failure rate.

<u>*TGRAM/TGRAL Switch Replacement*</u>



The TGRAM/TGRAL (Transfer Ground Rocker Arm Main/ Transfer Ground Rocker Arm Line) switches represent an extremely antiquated type of underground oil switch. Vendors first introduced these switches in the 1920s. The design was obsolete by the 1960s. PG&E uses its TGRAM/TGRAL switches (1940s vintage) to sectionalize PILC cable. PG&E generally uses a three-way configuration, associated with a submersible transformer bank feed. The picture to the left shows a typical switch of this type. PG&E initially had approximately 1,000 such switches in service. The Company began a replacement project in 2009. Year end 2011 showed 616 switches remaining to be replaced.

PG&E has determined that these types of oil switches create inappropriate risk. Failure could occur during operation or maintenance, or in connection with the failure of nearby equipment. These oil switches have a history of comparatively high failure rates. The majority of these switches came from a single vendor. That vendor has issued several "Remove from Service" safety notices for these switches. The first service notice came on August 1, 1983. It recommended replacement with newer switches. A second, more strongly worded notice came on July 10, 1985. This notice cited switch failures involving "serious injuries and in some cases fatalities." A third notice came on March 21, 1997. This third vendor notice again "strongly recommend the de-energization and removal" of these switches. Approximately 500 of these switches remained in service on PG&E's system at the end of 2012.

PG&E has assessed the condition of these remaining switches, and has classified them into eight tiers. The GRC forecast includes removal of all remaining switches by the end of 2016.

Tie Cable Replacement

PG&E's tie cables serve as express bulk power 12 kV feeders. They run from one distribution substation containing a transformer bank to another distribution substation containing a set of switchgears for distribution to customer transformers. PG&E has used tie cable circuits in San Francisco and Oakland due to the limited number of transmission circuits in the area.

The PG&E proposal to replace this cable comprises a safety initiative; these cables are similar in nature to the network cables. These cables serve as parallel feeders. They release substantial fault energy in manholes when they fail. Like network cables, failures in tie cables can cause manhole cover displacements, and cause secondary gas explosions in the manholes.

PG&E forecasts the replacement of all PILC tie cables in East Bay by 2016. The cables being replaced have 1935 to 1948 vintages. These tie cable replacements represent the end of a decade-long plan to replace all tie cable circuits. PG&E started this replacement plan in 2003. The Company has replaced eleven circuits in San Francisco, with one project currently underway.

c. Justification

As is true for the other GRC Exhibit 4 initiatives, we found no structured risk assessment of cost/benefit analysis underlying the underground projects and programs addressed in Chapter 16. They do, however, contribute to mitigation of important safety risks.

We found that the network cable replacement initiative contributes to system safety by reducing the number of manhole explosions and fire risk. These cables are reaching the end of their useful lives. The cable failures create manhole explosion and fire risks when they fail.

We also found that the TGRAM/TGRAL switch replacement initiative contributes to employee safety by removing highly dangerous equipment. These switches comprise an antiquated type of underground oil switch. The switch vendor has issued several "Remove from Service" safety notices regarding them. The initiative will eliminate all of the switches by the end of 2016.

We also found that the tie cable replacement initiative contributes to system safety by reducing the number of manhole explosions and fire risk. Liberty considers this cable replacement to be a safety initiative because the cables are similar in nature to the network cables. Just like the network cables, the tie cable failures can cause manhole cover displacements and ignite secondary gas explosions in the manholes. These tie cable replacements represent the end of a decade long term plan to replace all of the tie cable circuits.

10. Exhibit 4 – Chapter 17 –Automation & System Protection

a. Description

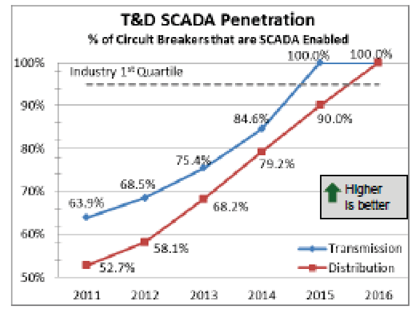
The next table lists the initiatives in this chapter and Liberty's classification of each.

CRG Exhibit 4 Automation and System Protection Expenditures

Safety Risk	Requester	PGE-4 Chapter #		Cost Type	MWC	2011 Recorded	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Base Activity	Dist Automation and System Prot	17	T&D System Automation	Exp	HX	$ 2,081	$ 3,189	$ 2,027	$ 2,027		
Base Activity	Dist Automation and System Prot	17	E Dist Automation and Protection	Cap	09	$ 745	$ 665	$ 3,623	$ 4,154	$ 4,085	$ 4,313
Safety per PGE & Liberty	Dist Automation and System Prot	17	Install Substation SCADA	Cap	09	$ 17,555	$ 29,942	$ 34,650	$ 58,300	$ 59,600	$ 59,600
Safety per PGE & Liberty	Dist Automation and System Prot	17	Replace Substation SCADA	Cap	09	$ 845	$ 3,278	$ 1,000	$ 2,000	$ 2,000	$ 2,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Install Feeder SCADA	Cap	09	$ 14	$ 1,000	$ 3,000	$ 5,000	$ 5,000	$ 5,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Replace feeder SCADA	Cap	09	$ 2,819	$ 1,100	$ 3,000	$ 2,000	$ 2,000	$ 2,000
Safety per PGE & Liberty	Dist Automation and System Prot	17	Fire Risk Management	Cap	09	$ 79	$ 1,200	$ 2,000	$ 2,000	$ 2,000	$ 1,000

b. Specific Initiatives

Substation SCADA



SCADA systems serve critical roles in monitoring and controlling widespread electric grids. They provide real time data and control functions for system operators. Substation SCADA systems for most major utilities are approaching 100 percent saturation. The application of SCADA at PG&E lags the industry considerably. See the accompanying graph. PG&E's saturation is at 58 percent, compared with an overall industry position of over 95 percent. This initiative will continue the SCADA additions underway and bring PG&E to 100 percent by 2016 (except for 4 kV substations).

Capital		Units			
MAT	Ops & Automation Description	2012	2013	2014	2015
09D	Dist Substation SCADA circuit breakers	168	151	265	278
67	Trans Substation SCADA circuit breakers	120	139	157	157

PG&E applies a prioritization system to set the order for SCADA installations. The prioritization model takes into account factors that include number of customers served, Urban/Suburban/Rural classification, Distribution Center Consolidation needs, and distributed generation installed.

SCADA installations provide a critical safety tool for mitigating the down-wire risk to which the PG&E system is particularly vulnerable. Downed electrical conductors remain energized 36 percent of the time (on the ground or on objects). Vehicle accidents have produced a number of occupant injuries and fatalities when exiting vehicles. First responders to the accident scene also face risks from conductors that have remained energized. The absence of SCADA inhibits line de-energization before Troublemen can arrive. Troubleman callout and arrival time can take up to an hour. SCADA control will allow the system operator to interact with 911 responders and to de-energize the line via remote control. Even de-energized down lines are not completely safe until grounding, but they are much safer than energized ones.

Feeder SCADA

Feeder SCADA consists of both new installations and replacements of older SCADA systems. PG&E is installing the new installations in locations where they can contribute to system safety (*e.g.*, urban and high pedestrian-traffic areas). The next table shows the numbers of installations included in the GRC forecast. PG&E's system employs about 6,000 reclosers.

GRC Forecast of SCADA Installations

Situation	2014	2015	2016
Installing radio communication to existing SCADA-ready devices	18	18	18
Upgrading existing controls to SCADA operability	170	170	170
New locations	50	50	50

PG&E has targeted another SCADA feeder initiative at replacing existing older SCADA controls. PG&E uses an older SCADA system, called PDAC (Primary Distribution Automation and Control). This system is over 25 years old. About 200 PG&E obsolete devices require replacement due to maintenance concerns. This initiative will replace about forty six devices per year, over a five-year duration.

The purpose of the SCADA feeder replacement subprogram is to perform lifecycle replacements of existing obsolete or unreliable feeder SCADA switches before they are rendered inoperable, thus posing potential safety or reliability risks. PG&E bases prioritization for selecting SCADA PDAC switch replacements on selection of the oldest vintage units, and prioritizing their replacement on the basis of criticality of the circuit. The Company's approach uses parameters such as the number of customers served and device performance. The objective of this subprogram is to replace feeder SCADA switches prior to failure.

Fire Risk Management

PG&E's Fire Risk Management (FRM) subprogram supports its public/system safety improvement initiative by reducing rural fire danger. Part of PG&E's efforts to improve system safety by reducing fire risk associated with its distribution system includes the addition of SCADA operability to existing line reclosers in the high fire risk areas by upgrading controls (where needed) and installing communications equipment. PG&E will then be able to change relay settings remotely during high risk times to non-automatic reclosing.

There are 615 reclosers in the high risk fire areas defined by the state. 375 reclosers are forecasted to be replaced in 2014-2016. Rather than use a scoring model, PG&E selected the device locations for SCADA installation under the FRM subprogram based on the California Department of Forestry and Fire Protection's Fire and Resource Assessment Program (FRAP) map zones (2010 Assessment). Deployments are occurring one division (geographic area) at a time to coincide with the rollout of the associated operating center control software.

c. Justification

As is true for the other GRC Exhibit 4 initiatives, we found no structured risk assessment of cost/benefit analysis underlying the automation and system protection work addressed in Chapter 17. The work, however, contributes to mitigation of important safety risks.

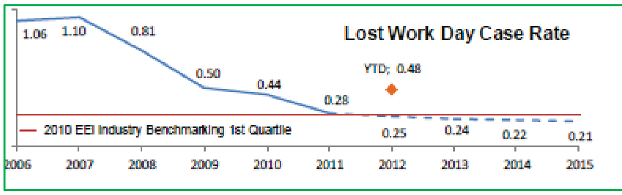
We found that the substation and feeder SCADA programs contribute to system safety by providing remote device-monitoring and operational capability. They are an important safety tool, providing remote monitoring and control capability. PG&E lags the industry considerably in the application of substation SCADA. This initiative will bring the substation SCADA capabilities at PG&E to industry levels by the end of 2016.

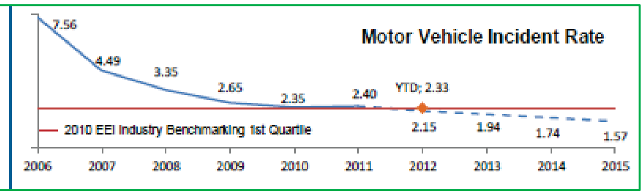
We also found that the Fire Risk Management SCADA program improves system safety by reducing the risk of wildfire ignition. The initiative provides SCADA monitoring and control for reclosers in the high risk fire areas. It contributes to system wildfire safety risk reduction by providing that monitoring and control.

F. Other Safety and Security Issues

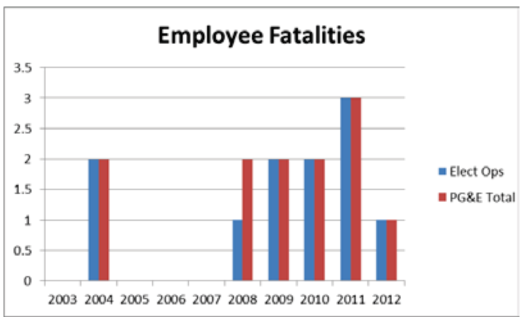
1. Employee Safety

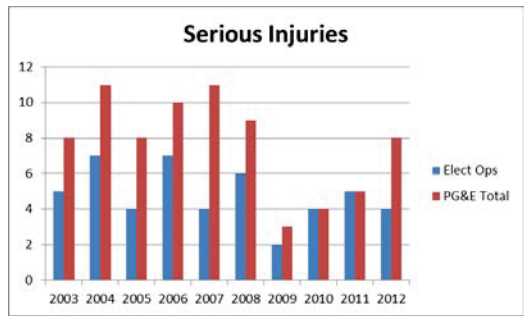
The graphs below show that Electric Operations has made progress in improving employee safety over the past six years. The final Lost Work Day Case Rate for 2012 was 0.38. The final Motor Vehicle Incident Rate was 2.059. These levels show substantial improvement over the 2006 levels.





Despite these positive trends, serious injuries and employee fatalities continue to be a problem requiring further mitigation.





In addition to employee fatalities and serious injuries, contractor fatalities and serious injuries are also a concern. Eight contractor incidents in 2012 resulted in a serious injury or fatality (four serious injuries; four fatalities). PG&E started formally recording and tracking contractor serious injuries and fatalities in 2012. Complete data is therefore not available for prior years.

PG&E realized some time ago that major and structural changes in the Electric Operations safety program were in order. The Electric Operations multi-year employee safety improvement plan focused on the following solutions and strategies:

- Create safety ownership at every level of the organization
    - Safety Management System
    - Safety Organizational Structure
- Shift the safety focus to recognizing and controlling exposure and risk
    - Hazard Identification and Risk Exposure Reduction
    - Near-Hit Reporting
- Enhance performance through training and development programs
    - Human Performance Tools
    - Critical Work Task Training

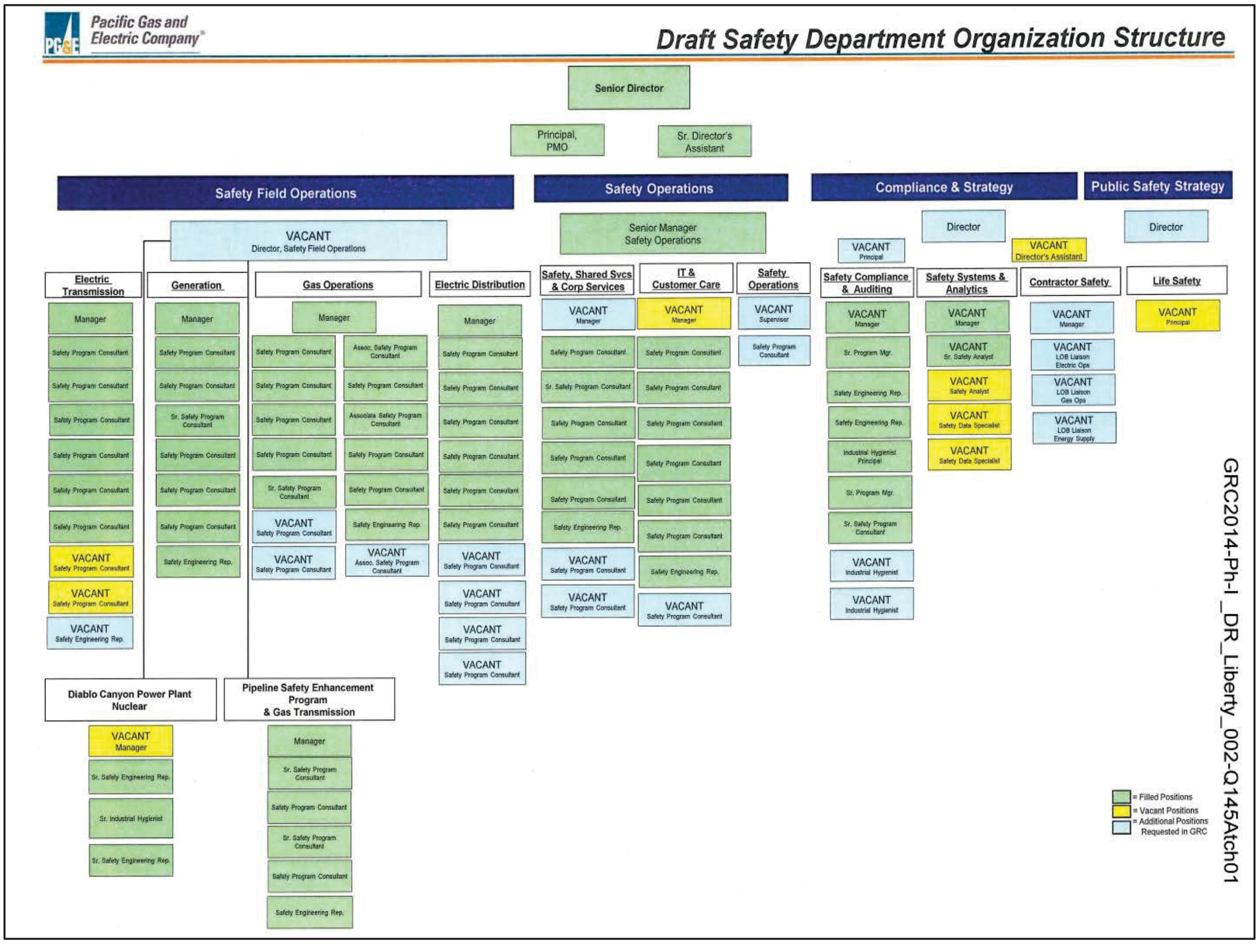
    - Hire-to-Retire Training Program
- Continuously improve by learning from industry best practices and internal safety audits and assessment

On November 3, 2011, the reorganization of Electric Operations resulted in the formation of a new safety team, (Electric Distribution Operations (EDO) Field Safety), dedicated specifically to helping improve organizational Safety and Human Performance. This team reports to the Executive VP – Electric Operations. The Field Safety Organization's primary goal has two fundamental components: (1) drive safe field practices and (2) assist in closing performance gaps. Approximately 2,200 field personnel form the focus of the EO Field Safety organization. Of this total, 1,800 work in Maintenance & Construction (M&C) and 400 work in in Restoration & Control (R&C).

Electric Operations Field Positions (Human Performance Specialist, Safety Program Specialist, and Safety Compliance Specialist) are titled differently from the corporate safety field positions. They are more methods and procedures oriented than are the corporate safety positions. Electric Operations has not yet completed the full staffing of these positions.

Grassroots Safety team participation in Electric Distribution Operations is also a focus area. Currently 233 field employees are on twenty six teams.

The Corporate Safety Department is also undergoing changes structured to address the safety performance. In 1997 PG&E decentralized the safety department. In 2005/2006 PG&E recentralized the safety department into the current group. The next diagram shows the draft Safety Department organization chart, reflecting a new organization structure. The chart identifies all filled positions (green), vacant positions (yellow), and new positions proposed in the GRC testimony (blue). The GRC forecast calls for adding twenty one employees to Corporate at an incremental cost of $3.6M.



Four new Safety Program Consultant positions are proposed for the Electric Distribution Field Operations group. Four positions are proposed for a new Contractor Safety group. The job responsibilities of the Safety Program Consultant positions are currently under review.

PG&E conducted benchmarking activities with Edison Electric Institute and the top seven utilities in safety performance. One recognized concern was the ratio of safety personnel to employees. The addition of the safety department personnel is directed at addressing this issue. Another issue is the amount of travel time for Electric Operations safety personnel due to the large service area. For example, between September 1, 2011, and February 29, 2012, the eight-person Electric Operations Field Safety team drove more than 235,000 miles – more than 4,900 miles (nearly 100 hours) per employee per month. Adding safety professionals means that time spent on the road will instead be spent at work locations providing safety guidance, conducting hazard assessments or conducting incident investigations.

We found that current serious injury and fatality levels require significantly greater mitigation. PG&E had one employee fatality in 2012 due to a vehicle accident. There were four contractor fatalities (one of these being in Power Generation). Employee safety is recognized as a serious concern. The current levels of serious injury are intolerable.

We also found that the new Electric Operations Field Safety Team is better positioned to improve safety performance in Electric Operations. The concept of applying field safety personnel experienced in electrical distribution work methods and procedures is modeled after other utilities.

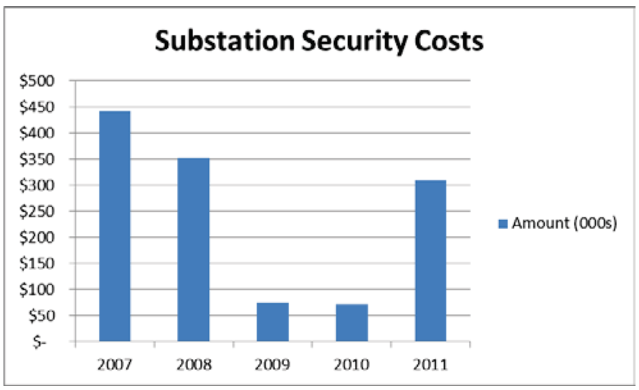
We also found that the addition of safety personnel is in line with other electric utilities and should contribute to improving field safety. The number of additional safety personnel being added will position PG&E in line with other utilities that are top performers in safety. This includes taking into account the numbers of safety personnel that were recently added from the new Electric Operations Field Safety organization.

2. Substation Security

PG&E has an operational risk titled *Electric substation physical reliability and security*. This was formerly an enterprise-level risk which was identified in 2010. The definition of the risk is, "*Criminal acts targeting PG&E that result in a risk to system safety, loss of life, catastrophic operational impact, or damage to the Company's reputation.*"

PG&E has issued mitigation plans since 2011. The risk assessment has determined that only transmission substations are at risk based on the definition. The transmission assets are not included in this GRC. PG&E did not deem distribution substations to be critical substations subject to targeted security risks. This determination is in line with industry and the 2012 National Research Council report on Terrorism and the Electric Power Delivery System. Distribution substations are targets of petty theft and vandalism, but not terrorist activity.

PG&E has an established distribution substation security program in place. This program addresses substation cyber assets, transmission substations and distribution substations. Distribution substations are divided into security classes. Managers can review the security classification of a substation and modify it as warranted by changing conditions at the substation. Corporate Security then applies security measures based on the classification of the substation. For distribution substations, security mitigation is an ongoing base activity with no apparent residual risk gaps. Exhibit 4 Chapter 13 contains $400,000 per year of expenditures for the installation of card readers at three San Francisco substations.



Distribution substation security incidents comprise an area where PG&E must maintain continued vigilance. The graph on the left shows the annual costs of all security incidents including, but not limited to theft, vandalism, etc.

Distribution substation security mitigation comprises a base activity; we observed no unaddressed risks. PG&E has a well-defined distribution substation security program in place. The program takes into account field needs and works closely with Corporate Security to put measures in place to meet those needs.

3. Public Outreach

From April 2004 to April 2012, almost 70 percent of all CPUC-reportable electrical contact incidents were from third party actions. It is by far the leading cause of reportable electrical contact incidents (see Section D.1). PG&E reported 73 individual incidents to the CPUC during that period. It is common in the industry for utilities to apply a robust public outreach program to help reduce third party electrical contacts.

Until early 2011, the Public Safety Section of the Safety Health & Claims department (now Safety Department) developed and implemented the Public Safety Information Program. The program's goal was to increase awareness of the safe and proper use of gas and electricity by the public, customers and targeted third-party groups, and help reduce the risk of property loss, injury and death. A full-time PG&E employee in the Safety Health & Claims department managed the program. PG&E contracted out the design of public safety literature and resources. PG&E targeted elementary and middle school students, agricultural workers, contractors working around PG&E facilities, and first responders.

Utility	Residential Meters (MM)	Public Safety Budgets	$/Meter
2011 Proposed Budget	4.6	$ 723,390*	$ 0.16
PG&E 2010 Enhanced	4.6	$ 541,535	$ 0.12
PG&E 2010 Original	4.6	$ 385,286**	$ 0.08
PG&E 2006	4.6	$ 777,588	$ 0.17
Utility A	3.1	$ 369,000	$ 0.12
Utility B	3.9	$ 472,000	$ 0.12
Utility C	0.522	$ 131,000	$ 0.26

Budgets for these programs tended to peak in the 2006 period, and then fell until 2011. Beginning in 2012, PG&E expanded the public safety outreach programs and reorganized the management to include different departments.

The Public Awareness Program in Gas Operations funds and manages the Contractor/Excavator Program, Agricultural Worker Program, and School Outreach Program. The 2013 and 2013 budgets are shown in the table below.

Public Awareness Program Expenditures

Program	2012 Recorded	2013 Forecast
Contractor/Excavator Outreach Programs	$400,765	$401,771
Agricultural Worker Outreach Program	$86,100	$86,700
School Outreach Program	$346,320	$346,000
Totals	$833,185	$834,471

In addition to this activity, PG&E has the following outreach programs, which we address below.

Vegetation Management Public Education - Tree Worker Public Safety Outreach Program

The Tree Worker Outreach program is a part of PG&E's VM program and includes communication materials, outreach efforts, and tree planting events. The 2007 to 2011 recorded amounts averaged $327,600. The 2012-2014 forecasts for public education are $360,000, which is consistent with past years funding.

Electric Operations Emergency Preparedness & Public Partnership

Electric Operations' (EO) Emergency Preparedness & Public Partnerships (EP&PP) Team coordinates closely with the Gas Operations team and focuses its efforts on more complex electric-related events. The EO Public Partnership team is currently comprised of two Public Safety Specialists who report directly to the EO EP&PP Manager. The key focus areas for the team include: coordinated response to wild land fires; storm-preparedness and outreach; underground vault incident response; and electric substation response coordination.

For these key focus areas, the Public Safety Specialists deliver training to external first responders on PG&E's capabilities and response approach. During actual incidents, the Public Safety Specialists directly integrate with the external first responder Incident Commanders to share information in order to address public safety issues, including the protection of PG&E assets. The close coordination between PG&E, Cal Fire, and United States Forest Service (USFS) was noted extensively during multiple 2012 fires. The 2013 forecast for two full-time public safety specialists and the EO EP&PP Manager (40 percent allocated to PP) is approximately $340,000.

"Wires Down" Campaign

Electric Operations added a new public outreach program for general public awareness/safety in 2012. This program focuses on public awareness regarding downed power lines. The target audience is adults. The goal is to educate consumers on the danger of power lines and empower them to know what to do if they encounter a downed line. This is a four month campaign with a budget of $1.05 Million.

Community and Employee Engagement Team

The Community and Employee Engagement team manages the deployment of interactive gas and electric safety displays designed to educate customers, community members and children on safety awareness around PG&E's gas and electric facilities (See Exhibit PG&E-9, 9-11, This work began in 3Q of 2012 and will continue through 2013. The recorded costs for the safety board work in 2012 were approximately $650,000. The costs were split between Gas Operations, Customer Care and Electric Operations. The Community and Employee Engagement department consisted of twelve employees in 2011 (see WP 9-10, line 2, portion of total). In 2011, the total allocation was approximately 50 percent BTL (below the line). For 2014, PG&E forecasts it is going to do more work that is BTL and will increase its allocation to 80 percent BTL (see WP 9-31). PG&E does not expect staffing and funding levels to change in 2014.

Customer Care

Customer Care's Customer Education and Outreach efforts include the Electric and Gas Safety and Reliability Outreach initiative. This initiative aims to increase customer awareness and understanding of how to handle potentially hazardous situations involving electricity and gas. In addition, PG&E has found "electric safety board" public demonstrations to be effective in building awareness with customers in the case of a fallen power line and outage impacts.

PG&E plans to expand community-oriented and local outreach that will focus on general gas and electric safety awareness and education. PG&E plans to focus electric and gas safety and reliability outreach efforts in schools, community events and other customer interactions in the field in order to increase general understanding of electric and gas utility safety practices. The following electric and gas safety and reliability activities are proposed to improve safety and awareness: Local Events; Locally Targeted Media; Locally Targeted Outreach; Printed Collateral and Online Communications; and Labor. The forecasted 2014 expense for these activities is $5.4 million, which includes content development and updates to educational materials and online content.

We found that, since 2010, PG&E has substantially increased public outreach programs to reduce electrical contact incidents. Third party actions are by far the leading cause of reportable electrical contact incidents. Overall PG&E has greatly increased their public outreach programs and focused on downed electric conductor safety. These programs are anticipated to contribute to reduced third part contact incidents.

4. Safety Performance Metrics

a. Employee Safety

Employee Safety Metrics

	Ref #	Metric YTD Data through July 2012	YTD Actuals	YTD Target	YTD Amber Threshold	YTD Green Threshold	EOY Forecast	EOY Target	EOY Amber Threshold	EOY Green Threshold
Employee Safety	1	OSHA Recordable Rate[1]	2.485	Tracking Only			N/A	Tracking Only		
	3	Lost Work Day Case Rate [12]	0.477	0.249	0.261	0.249	N/A	0.249	0.261	0.249
	5	Motor Vehicle Incident Rate[1]	2.33	2.15	2.26	2.15	N/A	2.15	2.26	2.15
Public Safety	8	Wires Down	1,545	977	989	977	TBD	1,611	1,631	1,611
	9	Response to 911 Calls Within 60 Minutes	77.2%	70.2%	67.9%	70.2%	78.0%	70.0%	67.7%	70.0%
	10	Network System Failures	3	6	7	6	11	11	12	11
	11	Secondary Network System Failures	2	Tracking Only			Tracking			
	12	Incidents Resulting from Equipment Failures	1	0	1.17	0.58	1	0	2	1
	13	High Consequence EC Tag Completion	96%	100%	92%	96%	97%	100%	92%	96%

PG&E used industry-standard performance metrics for tracking employee safety (see table above). The definitions of these metrics are:

- Lost Workday (LWD) Case Rate – The number of LWD cases incurred per 200,000 hours worked, or for approximately every 100 employees.
- Preventable Motor Vehicle Incident Rate – The total number of motor vehicle incidents that the PG&E driver could have reasonably avoided, per one million miles driven. Starting in 2013, PG&E will replace the Preventable Motor Vehicle Incident Rate performance metric, with the Serious Motor Vehicle Incident Rate.
- OSHA Recordable Rate – PG&E has used the OSHA Recordable Rate as one of the key safety metrics for many years. In 2012, however, in an attempt to address the potential

risk of creating an incentive that could lead to under-reporting of employee injuries, they placed less emphasis on the OSHA Recordable Rate and removed the metric from their incentive targets. PG&E continues to track and report the rate, but did not establish performance targets. The rate calculation is the number of work-related injuries per 200,000 hours worked.

- Near Hits Reported – This is a new metric for 2012. Employees are encouraged to report near misses.

We found that the employee safety metrics area has been subjected to well-established, comparable measures between utilities and other companies. Traditional metrics for employee safety are the Lost Workday (LWD) Case Rate, Preventable Motor Vehicle Incident Rate, and OSHA Recordable Rate. The CPUC should continue to use these traditional metrics. They provide a consistent long term view and offer a comparable metric with other industries. The last three fatalities at PG&E have involved motor vehicle accidents. Once it has been established, the Serious Motor Vehicle Incident Rate could be added as a metric.

We also found the addition of a zero employee fatality goal to be appropriate. PG&E has occasionally experienced a year with zero fatalities. A zero employee fatality goal will be challenging due to the large size of the Company, but it should be considered. It is a common goal for many utilities. If the safety of employees, contractors and the public is to be improved, employees will need to lead the way.

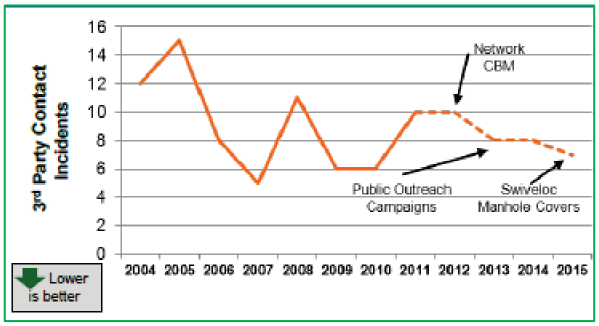
b. System Safety

The next table shows PG&E's current system safety metrics.

System Safety Metrics

2012 Metrics	Target	YTD (Nov)
Electrical Incidents resulting from equipment failure	0	1
Network system equipment and primary cable failures	11	9
T&D wires down (with exclusions)	2687	2673
911 emergency response - within one hour	77%	84%
High consequence EC tag completion timeliness	100%	99%

We found the T&D Wires Down (with exclusions) metric to be appropriate. The wires-down metric puts into play a number of issues at PG&E. Measurements are affected by the conductor replacement program, vegetation management program, pole replacement program, line inspection program and the infrared program. The metric is also important to system safety. It is broad-based and requires efforts in every division.



We also found the Electrical Incidents Resulting from Equipment Failure metric to be less meaningful than a Third Party Contacts Incident metric. The Electrical Incidents Resulting from Equipment Failure metric has a very narrow focus. Based on past history it will generally be either zero or one for the year. The Third Part Contacts metric includes electrical incidents from equipment failure. PG&E currently tracks this metric (see graph). This metric is impacted by programs such as equipment maintenance, line inspection and public outreach programs.

We also found that the *Network System Equipment and Primary Cable Failures* metric should be monitored for eventual removal. With forecasted network funding and improvements this metric will become less relevant each year. It is also a narrow metric from a corporate viewpoint since it is only in play in the bay area.

The bar can be raised for the *911 Emergency Response* metric. The bar is set low for this metric. It is currently easily being met.

A Replacement $/ft. Target for #6 Cu Conductor metric is appropriate. The magnitude of the small conductor replacement problem will require a well-managed long term effort. The unit cost of circuit replacement would be a good measure of the overall efficiency of the program. This metric would be impacted by actions such as conductor replacement program management controls, engineering and construction efficiency, and planning.

5. Root Cause Analysis

Root cause analysis is a problem solving tool that should form part of a risk assessment program. PG&E uses root cause analysis in several different situations.

Root cause analysis is a fundamental element in addressing employee safety. For every serious injury to an employee, PG&E's Serious Incident Analysis Resource Manual requires that an incident analysis team be formed and a root cause analysis be conducted. This action is a critical part of lessons learned evaluations and follow-up actions. This is a best safety practice.

Root cause analysis is not necessarily a fundamental part of public safety accident investigations. These incidents are generally investigated and controlled as Attorney-Client privilege. Admissions of error are not disclosed for legal reasons. Also, access to information from the injured party is not readily available. This is not to say that a corporation does not learn lessons or conduct follow-up due to public incidents. This is often done, but the follow-up is generally not formally associated with a particular incident.

There are several situations where root cause analysis is used to analyze distribution material failures. Due to the thousands of failures occurring each year, the normal outage report only contains an overall categorization of each failure. Only selected failures are examined in detail. The situations where a root cause analysis is conducted in Electric Operations are:

- Material Problem Reporting: Electric Operations has a Material Problem reporting procedure in place. Any field employee can request any specific material failure incident be investigated for root cause. It is standard in the industry to perform root cause material investigations on an as-needed basis.
- Wires down Investigations: Electric Operations has elected to perform a root cause investigation on every wire down situation in order to gather detailed failure data. This data will be used to inform and direct maintenance plans.
- Asset Maintenance Plans: Root cause analysis is often used as a part of data gathering to inform and prepare asset management plans. Electric Operations does not have a formal asset management system in place.

- Vegetation-caused Outages: Electric Operations investigates all vegetation-caused outages by an Arborist in order to determine the root cause.
- Risk Mitigation Plans: PG&E risk response plan templates include the analysis of risk drivers, which are root causes, as a part of the risk response plans.

We conclude that root cause analysis has been incorporated as an effective problem solving tool in electric Operations. As noted earlier, however, PG&E needs to assure that it populates data regarding system events robustly.

V. Other LOB Safety Projects and Programs

We also reviewed the projects and programs proposed by other LOBS to the extent that they involved safety or security initiatives.

A. Safety Department

PG&E's corporate Safety Department has responsibility for identifying, evaluating and controlling hazards, risks, and exposures to protect employees and the general public. The Safety Department has received considerably more emphasis in the past two years since the San Bruno incident. The Company established a lead safety officer position in 2011. The Safety Department establishes the overall framework for corporate-wide programs, and has developed and implemented new strategies and initiatives for the purpose of enhancing public and employee safety. Key components of the overall safety program include OSHA compliance, occupational injury and illness prevention, public safety, safety training, field safety observations, hazard and risk analysis, industrial and office ergonomics, motor vehicle safety, root cause incident investigations, and external benchmarking. The GRC includes several new safety initiatives that the Company believes will enable it to mitigate safety support gaps in field operations and that focus on incident prevention. The following table includes the new safety requests in the GRC forecast; all comprise expense items.

GRC New Safety Department Expenditure Requests

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Safety Department	Exh 7 Chap 2	Operational safety team labor escalation new hires	Exp	$ 127	$ 173	$ 178		
Safety Department	Exh 7 Chap 2	Operational safety increase 3 managers 8 safety consultants	Exp	$ 1,550	$ 1,550	$ 1,550		
Safety Department	Exh 7 Chap 2	Operational safety team 2014 10 additional staff	Exp			$ 1,335		
Safety Department	Exh 7 Chap 2	Safety Audit program	Exp			$ 225		
Safety Department	Exh 7 Chap 2	Contractor safety program	Exp			$ 150		
Safety Department	Exh 7 Chap 2	Pandemic Supplies	Exp			$ 275		
Safety Department	Exh 7 Chap 2	Migration of files	Exp			$ 250		

PG&E has requested 21 additional safety department employees in the GRC. The previous Director of Safety prepared the GRC safety initiatives and incremental expenses. A new director has come on board since then. The additional employees include three new managers for each of safety field operations, compliance and strategy and public safety strategy, and eight safety program consultants, planned to be hired in 2012 at cost of about $1.55 million per year. The GRC forecast includes 10 additional safety staff, including safety engineers and the safety program consultants, planned for hiring in 2014, at a cost of approximately $1.34 million.

The approach of the new incumbent includes an increased focus on safety compliance and auditing, contractor safety, public safety, and field operations support. Implementation of this new strategy, as developed by the new director, will cause the changes shown in the organization chart from the preceding chapter.

The new senior director's approach does not require significant changes to what the GRC testimony already provides, according to the Company. The recently reorganized Safety Department continues to require approximately 21 additional positions. PG&E, however, has advanced the schedule for filling remaining positions from 2014 to the end of the second quarter 2013.

The GRC request also includes incremental expenses for public safety materials initiated in 2011, a safety audit program, a contractor safety program, pandemic supplies, and safety files migration. PG&E proposes to initiate in 2013 the activities that drive these incremental expenses, which the Company estimates at about $1.6 million per year.

PG&E has adopted the goal of reaching first quartile corporate safety performance. The Company is now determining what schedule to adopt for reaching this performance level. For the immediate term, a key safety goal for 2013 is to produce a 25 percent reduction in lost work days. That metric does have a target date (2015) for achieving first quartile performance.

A PG&E leadership safety assessment report in 2012 identified several gaps in the safety program. The Company has used this assessment, coupled with its benchmarking efforts, to address gaps in the safety program through new initiatives included in the GRC. These GRC initiatives do not find support from the new corporate risk assessment programs or cost-benefit analysis in the GRC, or in information that we learned during our review.

B. Corporate Real Estate

The next chart summarizes some of the changes that PG&E proposes with respect to real estate expenditures.

Real Estate Expenditures Identified by PSE&G as Safety Related

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Upgrade Program 12 buildings, reviews and upgrades	Cap	$ 1,769	$ -	$ 1,549	$ 401	$ -
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Program	Exp	$ 6,492	$ 3,912	$ 4,191	$ 4,300	$ 4,500
Corporate Real Estate	Exh 7 Chap 6	ADA program	Exp	$ 388	$ 484	$ 527	$ 527	$ 527
Corporate Real Estate	Exh 7 Chap 6	ADA assessments	Exp	$ 3,211	$ 3,307	$ 5,909	$ 5,909	$ 5,909

To assist in risk mitigation efforts, corporate real estate (CRE) has designated buildings that support activities critical to operations. These business-critical buildings include the Company's general office (which houses the San Francisco data center, gas control center, electric transmission operations center, and energy trading center), the Fairfield data center and security control center, and the Vacaville grid control center. CRE will improve the reliability of these buildings through seismic upgrades and maintenance to minimize the risk of interruption to these critical services. PG&E expects to complete structural seismic safety work at approximately 15 additional buildings by the end of 2016. CRE will also support reliability by creating a dedicated unit to operate and maintain these business critical operations.

PG&E's enhanced Americans with Disabilities Act (ADA) compliance program will improve safety for visitors and occupants of PG&E's facilities. With the assistance of external ADA experts, CRE will conduct ADA accessibility assessments at approximately 190 buildings to identify and implement accessibility improvements. The scope of the enhanced ADA compliance program goes beyond the scope of work and the surveys performed previously. Multiple access and egress routes in restrooms within the buildings that will be evaluated as part of the compliance program must be evaluated and upgraded as necessary because customers and the public meet with employees in interior offices and conference rooms.

The work associated with seismic issues represents a completion of work initiated some time ago and reviewed previously. We did not consider it a new initiative, and therefore did not review it. PG&E designated GRC expenditures associated with ADA as safety-related. When we interviewed Company representatives, the rationale for this designation was that, while the ADA compliance activities in question here address access, such access must be provided in a safe manner. We did not find that explanation, however important ADA compliance is, to establish a safety nexus that is beyond what is normally expected for routine operations. We did not further examine the ADA expenditures.

C. Transportation Services

Transportation Services Expenditures Identified by PSE&G as Safety Related

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Transportation Services	Exh 7 Chap 3	Vehicle Safety & Opers Technology Projects	Exp			$ 1,000	$ 1,000	$ 1,000
Transportation Services	Exh 7 Chap 3	Incremental Vehicle Purchases	Cap			$ 52,000	$ 59,000	$ 46,000

PG&E has proposed the replacement of vehicles that have exceeded their lifecycle, or will exceed their lifecycle during the GRC period. The Company represents that this program is essential to maintaining a safe and reliable fleet that can reliably respond to operational issues. Transportation Services' vehicle replacement plan will enhance public and employee safety, maintain environmental compliance, and minimize vehicle downtime and repair costs. Achieving these objectives depends on replacing vehicles and equipment in a prudent fashion once assets have reached the end of their established life cycle. In light of the importance of the timely replacement of vehicles and equipment to the fundamental mission of Transportation Services, it has developed a five-year vehicle replacement plan designed to improve service quality and efficiency, and decrease the costs that are incurred through the retention of older assets. In 2014, 70 percent of the transportation services capital budget forecast is to comply with the negotiated California Air Resources Board alternative compliance plan.

The safety nexus PG&E asserts for this program is that, while obsolescence is the basis for proposed vehicle replacements, safety is implicated because using older vehicles is not as safe. We did not find that explanation sufficient to make vehicle replacement a safety versus an efficiency and environmental compliance based decision. We did not review this program.

PG&E has developed a safety initiative in which transportation services will implement onboard fleet telematics designed to reduce the risk of accidents, thereby increasing driver safety. This initiative includes associated back-end systems needed to track and store the data produced by this technology. A telematics system will allow transportation services to track driving patterns, including: speed, lane departure, collision avoidance, and monitor driver reaction. The system includes backing technology and dashboard cameras for 900 vehicles in phase 1 and 1,800 vehicles over the three-year GRC cycle.

D. Corporate Security

GRC Corporate Security Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Corporate Security	Exp 9 Chap 3	Corporate Security New Employees	Exp	$ 223	$ 514	$ 981	$ 1,010	$ 1,041
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Exp			$ 1,000		
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Cap			$ 500	$ 650	$ 700
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Exp			$ 470		
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Cap			$ 1,720	$ 1,920	$ 1,520
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Exp			$ 200		
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Cap			$ 500	$ 500	$ -
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Exp			$ 375		
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Cap			$ 150		

PG&E Corporate Security has responsibility for security in facilities across the Company footprint. Corporate Security plans made part of the GRC include an increase in staffing and four information technology projects designed to replace certain assets and to enhance physical security programs.

PG&E plans to add four new physical security specialists to assess existing security measures and to identify additional measures needed to prevent criminal activity at the Company's approximately 5,000 facilities. This request includes a security director with expertise and knowledge in physical security mitigation strategies, cyber security vulnerabilities and risk modeling and intelligence gathering to support the use of technology and data analytics in security. The current security director will retire within one year; the Company is bringing in his replacement in advance and will provide for training and transition.

One of the new physical security employees will manage the life safety program. The department now employs a life safety program manager for safety, security and real estate at the headquarters building. The new employee will have responsibility for all other facilities, to assure robust and coordinated attention to these areas company-wide. The GRC includes the addition of two full-time and one part-time physical security specialists to heighten physical security programs and combat criminal activity targeting PG&E assets, and to provide for increased employee and public security at facilities. PG&E explains that corporate security needs have expanded greatly over the years since 9/11. For instance, FERC hydro-security regulations have increased, and new TSA guidelines were issued in 2007. Enhanced levels of security using updated technology have become both required and desired. During the past five years, PG&E has greatly expanded its security philosophy and its workload. Numerous new security initiatives are already in place, and the Company needs additional staff to catch up with the previously expanded work load.

Two additional employees in the business continuity and emergency management area will be added to perform business continuity planning and standards certification consistent with Department of Homeland Security requirements. A second employee will perform business impact analysis at the Company (last performed in 2010 and 2011). More frequent business impact analysis is driven by an increasing dependence on technology and by changes in the IT sector. The Company notes the business impact analysis is also required for effective disaster recovery planning.

The next table shows the GRC cost of the 6.3 additional full-time-equivalent employees. PG&E added the 2.3 physical security specialists in 2012, with the security director planned for 2013, and two new business continuity specialists and the life safety specialist in 2014.

PG&E did not use formal risk assessments to justify the additional staffing requests and we have not found specific cost-benefit analysis to underlie them.

Corporate security also requested four IT programs in the GRC: the security management system implementation, corporate security asset management, physical security incident management and business continuity communication projects. The first project addresses replacement of over 60 outdated employee access card systems to improve facility security, and includes servers, software training and licensing with a three-year rollout period. The security asset management investments comprise replacements of security assets that include video cameras and alarm controls that are up to 20 years old. The investments also will upgrade asset databases. The program includes a $5 million investment in assets over the three-year rollout period, as well as training, maintenance and license expenses in 2014. The incident management program will provide a software platform that enables the security system to operate effectively. PG&E proposes to implement it in 2014 and 2015. Company management notes that its security equipment is dated, and that PG&E fell behind in replacing the equipment over the past 10 years. Replacement on a five-year cycle is desired for security equipment, and the Company believes that it needs to make these investments over a three-year period to get near such a cycle.

The Company also includes initiating an emergency management notification system to automate manual systems, plan activities resulting from a catastrophic incident, and allow company-wide communications after such an incident. PG&E conducted a pilot initiative under baseline funding in 2011, finding that it demonstrated the viability of such a system for use in emergency response. The table above shows the capital investment and operating expense related to these security-related initiatives. PG&E included written justification of each these projects in its GRC work papers, but has not performed formal risk assessments, or provided specific cost-benefit analyses to justify them.

E. Risk and Audit

GRC Risk and Audit Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Risk and Audit	Exh 9 Chap 3	Enterprise Risk Management 3 new employees	Exp	$ 540	$ 556	$ 573		
Risk and Audit	Exhibit 9 Chap 3	Enterprise Risk Management consulting	Exp			$ 50	$ 50	$ 50
Risk and Audit	Exh 9 Chap 3	Alternate Emergency Operations Center	Cap			$ 19,900		

The GRC request for the risk and audit organization includes two substantial capital projects: the Alternate Emergency Operations Center (AEOC) and the alternate Company headquarters (AC HQ). Together they involve a capital investment of almost $20 million.

PG&E currently maintains a full emergency operations center adjacent to its headquarters site in downtown San Francisco. The Company also has both an alternate headquarters and an alternate emergency operations center at another location. However, both locations lie within the Hayward primary earthquake zone, which could render both partially or totally unusable in a major seismic event. The US Geological Survey estimates that this area faces a 63 percent probability of a 6.7 or greater earthquake over a 30-year period. PG&E's emergency plan and business continuity plans call for an alternative headquarters site and an alternative emergency operations center outside major earthquake zones. The Company notes that no specific site has been picked for these backup facilities. This particular risk was one of the top 10 risks identified in the enterprise risk management program, which included a mitigation plan for the risk and estimated funding requirements.

As noted in the table above, PG&E's estimated construction costs are $13 million, and IT costs are $6.9 million for the two facilities. The GRC work papers noted that, "The project will improve the likelihood that PG&E will be able to restore essential emergency command and service restoration in a timely fashion following an event that renders the facilities in San Francisco and San Ramon inoperable." PG&E did not prepare a quantified assessment of event probability times the event consequences for comparison to expected facility costs. This GRC request was not founded on a formal risk assessment and PG&E has provided no cost-benefit analysis.

As noted elsewhere in this report, the corporate risk management organization is taking an expanded role in managing risk at PG&E, including establishing and managing a operational risk management program. Due to its expanded role, the risk management team will add three additional staff, including a manager, an additional principal and a business analyst. Previously, the risk management team had two principals. The three additional employees were to be hired in 2012 with a burdened cost of about $540,000 annually, as noted in the table above. Additional consulting expense related to risk management activities of $50,000 per year is also included.

F. Human Resources

The Company believes that a key to providing increased levels of safety and reliability set forth by the LOBs is the ability to attract and hire qualified employees. The HR department is forecasting an increase in the number of recruiters, continuation of the work force development programs, and technology enhancements so that PG&E can attract, select and hire skilled and qualified workers required to deliver safe and reliable service to customers. With a significant number of employees expected to retire from PG&E in the coming decade, the human resources organization must be proactive in developing sourcing strategies and partner with organizations that can work with PG&E to build the skills of prospective employees.

Human resources will develop and deliver training for new and long tenured employees so that they have the knowledge and skills necessary to safely and correctly perform their assigned work. The GRC forecast includes an increase in funding for PG&E Academy to provide instructional design, oversight of curriculum development, and resources to support the ongoing maintenance of training that is developed so that employees are trained to perform work according to the most current regulations, follow correct procedures and given the know-how to use required equipment.

We view the need for attracting and hiring qualified employees as serving a broad set of purposes. We did not find these efforts to have a sufficient safety nexus to call for our examining them.

G. Justification for Shared Services and A&G GRC Initiatives

The Shared Services and Administrative and General support organizations' safety and security spending in GRC forecasts were generally justified by written arguments, and not by risk assessments or cost/benefit analysis.

The GRC includes several new corporate safety initiatives from the Shared Services Safety Department that PG&E believes will enable it to mitigate safety support gaps in field operations and new safety initiatives that address incident prevention. The Company has requested 21 additional safety department employees in the GRC, including three new managers, for a 2014 cost of about $3.1 million. The GRC request also includes incremental expenses for public safety materials that were initiated in 2011, and for a safety audit program, a contractor safety program, pandemic supplies and safety files migration, all to be initiated in 2013. The total annual expense for these new programs is estimated at about $1.6 million per year. PG&E's leadership safety assessment report from 2012, coupled with benchmarking efforts, addressed gaps in the safety program through new initiatives that are included in the GRC.

PG&E corporate security is a central services organization in the Administrative & General LOB that is responsible for security in numerous facilities across the Company. Corporate security plans to increase its staff by 6.3 employees, including a new security director, at a 2014 cost of about $1 million. Corporate security is also planning for four information technology projects to make asset replacements and enhancements to the PG&E's physical security programs. The security assets and programs includes an $8 million investment in assets over a three-year rollout period from 2014 to 2016, as well as training, maintenance and license expenses of $2 million in 2014.

During the past five years, PG&E has greatly expanded its security philosophy and its workload. Numerous new security initiatives are already in place, and the Company represents that it needs additional staff to catch up with the previously expanded work load. Company management also reports that its security equipment and assets are quite dated, and that the Company fell behind in replacing security equipment over the past 10 years. Replacement on a five-year cycle is desired for security equipment, and the PG&E believes that it needs to make these investments over a three-year period to get near such a cycle.

The $20 million GRC request for the AEOC and the ACHQ included work papers noting that, "The project will improve the likelihood that PG&E will be able to restore essential emergency command and service restoration in a timely fashion following an event that renders the facilities in San Francisco and San Ramon in operable." A quantification of event probability times the event consequences as compared to cost were not prepared for the GRC justification in the work papers, and no specific cost-benefit analysis was performed.

The risk management team will also add three additional staff with a cost of about $540,000 annually; PG&E included written justification of each these projects in its GRC work papers.

The Company included written justification of each these projects in its GRC work papers; formal risk assessments or specific cost-benefit analyses were not used to justify these projects.

The following table identifies those initiatives and expenditures identified in the 2014 GRC as safety-related. Liberty has addressed each area identified in the table in the discussion above, with the exception of customer care initiatives. We did not find these efforts to have a sufficient nexus to electricity distribution or power generation.

Summary of Shared Services and A&G GRC Initiatives

Requester	Testimony Reference	Item	Cost Type	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
Customer Care	**Exh 5**							
Customer Energy Solutions	Exh 5 Chap 7	Elec and Gas Safety Outreach new program	Exp			$ 5,433		
Contact Center Operations	Exh 5 Chap 2	Customer Service Rep Training	Exp	$ 1,502	$ 1,542	$ 1,586		
Customer Advocacy Team	Exh 5 Chap 2	19 new CSRs and 1 supervisor	Exp	$ 1,677	$ 1,723	$ 1,770		
Customer Inquiry	Exh 5 Chap 2	Expand Sacramento and Fresno Contact Centers 135 seats	Cap			$ 15,495		
Office Services	Exh 5 Chap 3	Ergonometric Work Stations	Exp			$ 1,039	$ 1,134	$ 1,158
Office Services	Exh 5 Chap 3	Ergonometric Work Stations	Cap			$ 2,424	$ 2,646	$ 2,703
Revenue Assurance	Exh 5 Chap 4	13 New Field Reps	Exp			$ 1,300		
Metering	Exh 5 Chap 5	18 New Management Personnel	Exp			$ 2,075		
Metering	Exh 5 Chap 5	18 New Management Personnel	Cap			$ 818		
Shared Services								
Safety Department	Exh 7 Chap 2	Operational safety team 2011 public safety materials	Exp	$ 700	$ 700	$ 700		
Safety Department	Exh 7 Chap 2	Operational safety team labor escalation new hires	Exp	$ 127	$ 173	$ 178		
Safety Department	Exh 7 Chap 2	Operational safety increase 3 managers 8 safety consultants	Exp	$ 1,550	$ 1,550	$ 1,550		
Safety Department	Exh 7 Chap 2	Operational safety 2011 safety assessments one-time	Exp	$ -	$ -	$ -		
Safety Department	Exh 7 Chap 2	Operational safety team 2014 10 additional staff	Exp			$ 1,335		
Safety Department	Exh 7 Chap 2	Safety Audit program	Exp			$ 225		
Safety Department	Exh 7 Chap 2	Contractor safety program	Exp			$ 150		
Safety Department	Exh 7 Chap 2	Pandemic Supplies	Exp			$ 275		
Safety Department	Exh 7 Chap 2	Migration of files	Exp			$ 250		
Transportation Services	Exh 7 Chap 3	Vehicle Safety & Opers Technology Projects	Exp			$ 1,000	$ 1,000	$ 1,000
Transportation Services	Exh 7 Chap 3	Incremental Vehicle Purchases	Cap			$ 52,000	$ 59,000	$ 46,000
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Upgrade Program 12 buildings, reviews an	Cap	$ 1,769	$ -	$ 1,549	$ 401	$ -
Corporate Real Estate	Exh 7 Chap 6 Page 6-52	Building Seismic Program	Exp	$ 6,492	$ 3,912	$ 4,191	$ 4,300	$ 4,500
Corporate Real Estate	Exh 7 Chap 6	ADA program	Exp	$ 388	$ 484	$ 527	$ 527	$ 527
Corporate Real Estate	Exh 7 Chap 6	ADA assessments	Exp	$ 3,211	$ 3,307	$ 5,909	$ 5,909	$ 5,909
IT	Exh 7 Chap 8	Disaster Recovery Program	Exp			$ 3,100	$ 3,100	$ 3,100
IT	Exh 7 Chap 8	Disaster Recovery Program	Cap			$ 33,900	$ 44,000	$ 18,700
Admin and General								
Risk and Audit	Exh 9 Chap 3	Enterprise Risk Management 3 new employees	Exp	$ 540	$ 556	$ 573		
Risk and Audit	Exhibit 9 Chap 3	Enterprise Risk Management consulting	Exp			$ 50	$ 50	$ 50
Risk and Audit	Exh 9 Chap 3	Alternate Emergency Operations Center	Cap			$ 19,900		
Corporate Security	Exp 9 Chap 3	Corporate Security New Employees	Exp	$ 223	$ 514	$ 981	$ 1,010	$ 1,041
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Exp			$ 1,000		
Corporate Security	Exp 9 Chap 3	Corporate Security Management Systems Implementation	Cap			$ 500	$ 650	$ 700
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Exp			$ 470		
Corporate Security	Exp 9 Chap 3	Corporate Security Asset Management	Cap			$ 1,720	$ 1,920	$ 1,520
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Exp			$ 200		
Corporate Security	Exp 9 Chap 3	Physical Security Incident Management	Cap			$ 500	$ 500	$ -
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Exp			$ 375		
Corporate Security	Exp 9 Chap 3	Business Continuity/Emergency Management	Cap			$ 150		
Human Resources	Exh 8 Chap 4	E recruit project	Exp	$ 557		$ 240	$ 150	
Human Resources	Exh 8 Chap 4	E recruit project	Cap	$ 3,200		$ 1,200	$ 750	
		Support Services Safety/Security Capital		***$ 4,969***	***$ -***	***$ 130,531***	***$ 109,867***	***$ 69,623***
		Support Services Safety/Security Expenses		***$ 16,967***	***$ 14,461***	***$ 36,457***	***$ 17,680***	***$ 17,285***

Appendix A -- Evaluation Criteria

CORPORATE SAFETY & SECURITY RISK MANAGEMENT

1. The overarching framework for identifying safety and security related projects and programs should be clear, comprehensive, and appropriate.
2. Asset management strategic programs should incorporate risk management plans and procedures.
3. The process for prioritizing safety and security projects and programs vis-à-vis each other and with respect to meeting other objectives (e.g., reliability, environmental compliance, customer satisfaction) should be rational, comprehensive, and consistently applied.
4. The Company should have adopted and it should operate under duly emphasized corporate leadership and a program for broad and complete assessments and management of the safety and security risks that affect its operations.
5. The program for assessing risk should be actively overseen by the most senior levels of company management and direction.
6. There should be complete, comprehensive documentation of risk assessment goals, policies, procedures, controls, and metrics.
7. Risk assessment and management should be supported by adequate resources under a disciplined approach informed by current industry thinking and approaches.
8. PG&E's methods for performing and using risk assessments should be informed by a structured, comprehensive process for identifying best industry practices.

LOB-LEVEL SAFETY & SECURITY RISK MANAGEMENT

9. The Company should perform and maintain a current, comprehensive assessment of the system's physical condition; this assessment should rely upon comprehensive efforts to gather and assess system data and to assess causes of recurring problems.
10. Risk management should be incorporated into the planning and execution of LOBs at the operating level.
11. LOB activities should be supported by trained risk assessment resources and conducted under structured and comprehensive goals, policies, procedures, controls, and metrics.
12. The bottoms-up risk assessment of the LOBs should inform risk management activities at the corporate or enterprise level.

13. There should be a structured, evidence-based process for identifying improvement opportunities and for selecting from among them.
14. There should be a structured process for analyzing asset performance and performing condition assessment.
15. There should be a register of key assets supported by risk profiles.
16. Risk assessments should apply sound, accepted concepts and techniques supported by the appropriate levels of technical and operational expertise.
17. PG&E should execute and rely on current assessments of the probability and consequences of safety and security failures for customers, the public, and employees.
18. Assessments of safety and security risks should produce well-founded assessments of risk probability, consequence, mitigation measures, the costs of available mitigation measures, and the difference in risk probability or consequence produced by each such measure.
19. The selection of programs, projects, and other sources of expenditure should result from a careful consideration of a set of robust, fully considered alternatives.
20. The data used to identify and select from among alternatives should be clear, complete, and accurate.
21. The risk reducing characteristics of proposed programs, projects, and other sources of expenditure should be clear, convincing, and quantified to the extent practicable.
22. The degree to which further risk mitigation activities would produce incremental improvements and at what cost should be considered and should be retrievable.
23. Planned projects and programs should be fully reflective of and responsive to the results of CPSD inspections and audits.
24. Supporting systems and procedures should facilitate the execution and management of risk management plans.

SAFETY and RISK IN OPERATIONS PLANNING

25. Top down financial objectives that lead operations planning and budgeting activities should not foreclose full and careful consideration of risks as part of the planning and budgeting processes.
26. Operations planning should incorporate comprehensive risk assessments and analyses routinely and in advance of plan and budget formulation.

27. The projects and programs proposed should reflect and conform to the results of risk assessment processes; the linkage should be clear.
28. How assessments of safety and security risks are considered among other planning factors (e.g., service reliability and quality, customer satisfaction, environmental stewardship) should be clear.
29. It should be clear that the balancing of safety and security risks with other planning factors takes due account of rate and financial consequences, both short and long term.

RISK/REVENUE REQUIREMENT NEXUS

30. Rate filings should reflect an enhanced and specific approach to risk assessment.
31. The Company should provide sufficient explanation of risk-based plans and identify revenue requirements impacts to permit stakeholders and the Commission to make informed value judgments about them.
32. The Company should recognize and respond to the need for soundly connecting risk analysis and proposed expenditures.
33. The Company should have clear, executable, and appropriate plans for progressing toward a state that will conform its risk management processes to an industry leading position, particularly with respect to gauging the revenue requirements impacts of discrete projects and programs to address safety and security risks.
34. The current rate filing should permit the identification of projects and programs explicitly associated with discrete safety and security risks.
35. The Company should be able to demonstrate that the projects and programs proposed in the rate case to address safety and security risks represent optimum risk mitigation alternatives.
36. The Company should be able to demonstrate that its balance of expenditures proposed in the current filing has taken due account of all risks and needs (not just safety and security) with due consideration for overall rate impacts to customers.
37. The level of funding for safety projects and programs should be commensurate with appropriately and fully identified and assessed safety risks.
38. Proposed LOB and total safety expenditure levels should be commensurate with appropriately identified and assessed safety risks.