# Report on Information Technology and Selected Electric Distribution Issues in Pacific Gas and Electric Company's 2014 Test Year General Rate Case PUBLIC

Prepared testimony of
Gayatri M. Schilberg

JBS Energy, Inc.
311 D Street
West Sacramento
California, USA 95605
916.372.0534

on behalf of
The Utility Reform Network

California Public Utilities Commission
Application 12-11-009
May 17, 2013

## Table of Contents

## List of Tables



## List of Figures



## List of Attachments

## I. INTRODUCTION AND SUMMARY

This testimony is presented by Gayatri M. Schilberg, Senior Economist at JBS Energy, Inc., on behalf of The Utility Reform Network (TURN). Ms. Schilberg has testified on numerous occasions before this Commission. Her qualifications are found in Attachment 1.

As a result of our examination TURN makes the following recommendations:

With respect to Information Technology (IT) Projects for the IT Line of Business (MWC 2F for capital and MWC JV for expense):

- TURN's capital disallowances for IT projects (across all lines of business as described below) amount to a reduction of 25% of the capital requests. Therefore we reduce the Baseline expense request for support of those projects by 25% also, which equals a disallowance of $59 million in expense in 2014.
- For Lifecycle computing, disallow $2.7 per year (2014-2016) in capital due to a lower estimate of the costs for lifecycle replacement of client computing.
- For the Disaster Recovery Project, reduce the project by half. Disallow $18.5 million in capital in 2014, $22 million in 2015, and $9.4 million in 2016, as well as $1.6 million in expense in 2014.
- For Telecommunications Network Enhancement, we make adjustments to derive 70% of PG&E's requested increase. Disallow $16.4 million in capital 2014, $7.9 million in 2015, and $7.1 million in 2016, as well as disallow $1.1 million in expense in 2014.
- For Records Management Archival, the project should be paid for from its benefits. Disallow capital expenditures of $16.5 million in 2014, $17.6 million in 2015 and $10.4 million in 2016, as well as $4.1 million in expense in 2014.
- For the Service Management Project, TURN recommends $3 million in capital for a much smaller project to monitor IT health. Disallow the capital requests of

$4.26 million in 2013, $5.86 million in 2014, $5.84 million in 2015 and $7.435 million in 2016.

Regarding IT Projects for Electric Operations:

- Regarding the Data Historian Project TURN recommends disallowing the following capital: $12.3 million in 2014, $10.9 million in 2015, and $0.98 million in 2016. We also reject the expense of $0.2 million in 2014.

- For the Closed Loop SmartMeter Outage Management Integration Project, TURN does not recommend funding this project in 2015 and beyond. Disallow $2.9 million per year in capital in 2015-2016. PG&E also requests $1.1 per year in expense in 2015-2016 for this project, which we also reject.

- For Advanced Applications for Distribution Control Centers, TURN does not recommend funding at this time. Disallow capital of $3.8 million in 2015 and $5.7 million in 2016.

- For Electric Distribution GIS and Asset Management, we propose that expenditures for this ED-GIS project, combined with the numerous components of the Workforce Mobilization Project discussed below, be combined into a memorandum account capped at the expenditure levels proposed by TURN. After the projects are completed, PG&E must provide a combined ex-post benefit/cost analysis showing positive benefits (at least a B/C ratio of 1.0 over the combined projects) in order to obtain rate recovery of amounts recorded in the memorandum account.

- For the ED-GIS project we recommend a maximum of $91.6 million for 2011-2014.

- For the Outage Reporting and Analysis System Replacement Project, disallow capital of $3.3 million in 2013 and $4.5 million in 2014 as well as $362,000 in expense in 2014.

- For the Graphic Work Design Tools, disallow capital of $2.9 million in 2013, $3 million in each of 2014 and 2015, and $0.3 million in 2016, as well as $0.8 million in expense in 2014.

- For the SAP Plant Maintenance Module, TURN recommends no funding of Phase 5 of this project. Disallow $4.6 million in capital in 2016.

- For Project Management and Reporting Toolset Enhancements, TURN recommends no funding at this time. Disallow capital of $ 0.5 million in 2014, $6.19 million 2015 and $ 0.5 million in 2016, plus $ 0.5 million in expense in 2014.

- For Customer Connections Online Tools, TURN recommends no funding of this project by general ratepayers (disallow capital of $3.1 million in 2012, $ 0.83 million in 2013, $3.8 million in 2014, $3.2 million in 2015 and $3.2 million in 2016 as well as expense of $3.8 million in 2014). Any expenditure on this project should be paid for by a fee on the customers using this functionality (new business). The project is probably four times the size of what a tolerable user fee can support.

- For Workforce Mobilization and Scheduling,

    - For the Service Planners rollout TURN recommends a belt-tightening adjustment of 20% reduction. Disallow capital of $1.3 million in 2015 and $758,000 in 2016.

    - For the Scheduling Integration with Time Management, TURN recommends zero funding for this project. Disallow capital of $1.75 million in each of 2015 and 2016.

    - For the Mobile Devices for Additional Crew (Electric and Gas) TURN recommends zero funding for these projects. Disallow capital of $3.67 million in each of 2014 and 2015, and $3.56 million in 2016 (MWC 2F), plus expense of $325,000 in 2014 (MWC JV).

- For the Mobile Devices Replacement/Upgrade, disallow capital of $1.8 million in 2014, $6 million in 2015, $2.4 million in 2016, and expense of $440,000 in 2014.
- Summary: for the Workforce Mobilization and Scheduling projects we summarize the following disallowances: capital of $5.5 million in 2014, $12.7 million in 2015, and $8.5 million in 2016. Disallow expense of 765,000 in 2014.

With Respect to IT projects for Customer Care:

- For the Customer Interaction and Relationship Management Project, TURN recommends that this project be rescoped so that costs are more in line with financial benefits. Disallow the current project: capital of $12 million in 2014, $15 million in 2015 and $10 million in 2016, along with expense of $3 million in 2014.
- For the Interval Data Processing and Exceptions Management Project, we find that PG&E overestimates the necessity for prebill processing and thus the status quo is the more cost-effective option at the present time. Disallow capital of $15.5 million in 2014, $3.7 million in 2015, and $1.5 million in 2016. Authorize $2.8 million per year in expense to fund the existing platform.
- For Optimizing Time to Market Rates, disallow $6 million capital in 2015 and $6 million capital in 2016.

With respect to the measurement of electric reliability using the IEEE definition, we recommend:

- PG&E should be ordered to continue to report total outages, including Major Event Days (MEDs), in its annual report to the Commission.
- PG&E should recognize that the IEEE method of classifying MEDs does not work well for PG&E's data and that this is not a "gold standard" that is sacrosanct.
- PG&E should examine whether the IEEE definition is classifying too many small events as MEDs compared to the definition in D.96-09-045.

- PG&E should undertake analysis of the frequency and response to MEDs, as recommended by IEEE.
- Any utility-caused major outage should not be classified as an MED or allowed to be excluded for purposes of outage reporting and for the STIP program.

With respect to Electric Distribution Expense:

- TURN recommends that ratepayers be credited with 100% of the pole test and treat fees that are due. We therefore reduce the 2014 forecast for MWC GA by $1.6 million.

## II. INFORMATION TECHNOLOGY (CAPITAL AND EXPENSE)

Requested IT spending (capital plus expense) for the test year 2014 presents a huge increase over PG&E's already large recorded expenditure in the 2011 test year. Covering IT needs for all lines of business, and summing both capital and expense, the TY 2014 request for the year 2014 (in nominal dollars) is $820 million, compared to $489.9 million spent in 2011 (PG&E 7, WP 8-228 to 229). This represents a 67% increase over 2011 IT spend (nominal dollars).[1] We note that PG&E's request in its last GRC was also 67% more than its 2008 recorded IT spend.[2] PG&E must rein in these massive IT increases of close to 70% every three years.

Although annual capital IT spending is projected to decrease somewhat in 2015 and 2016, these sizeable requests represent a huge ratepayer burden, in part because they cover assets which are relatively short-lived (5 or 7 years in general for IT hardware and software, respectively). Thus each project undertaken now will need to be refreshed or rewritten in 5 to 7 years. Further adding to the ratepayer burden is the fact that few if any of these requested IT software applications (projects) are accompanied by financial benefits. PG&E has rarely justified its IT projects with benefit/cost analysis,[3] and when

---

[1] We use the term "IT spend" to include both capital and expense.

[2] A.09-12-020, PG&E-2, WP p. 2.

[3] For most projects PG&E presents costs and lists benefits, where the benefits are generally unquantified.

present at all the benefits cover only a small portion of the costs thereby creating a net cost to ratepayers. Thus we are faced with a requested IT portfolio which does not pay for itself (with benefits such as cost savings or cost avoidances), which the utility envisions as needing to increase by 70% every three years, and for which costs need to be incurred again in 5 to 7 years. This IT treadmill is not sustainable for ratepayers.

Evidence from PG&E indicates how an increasing proportion of PG&E's gross plant is composed of relatively short-lived assets (less than 10 year depreciable life). As of December 2002 1.43% of PG&E's $34 billion gross plant consisted of short-lived assets. By the end of 2012, 2.28% of PG&E's $47.5 billion in assets had a service life of less than 10 years. (TURN 75 Q 3).[4] Following the current trajectory of expanded IT requests, no doubt this percentage of short-lived assets will continue to increase, adding a rising load of depreciation expense to the IT treadmill.

PG&E's largest IT spending is on Application Development, and that spending is increasing over time. PG&E's portion of capital additions which is due to Major Work Category (MWC) 2F, "Build IT Applications and Infrastructure," is growing over time, from 7.9% of all capital additions in 2012 to a planned 9.5% of all capital additions in 2016.[5]

Various aspects of PG&E's IT treadmill are apparent in a comparative study of 17 utilities. The 2011 UNITE study of Application Development and Support (AD&S) shows the following facts (2011 UNITE study, *Application Development and Support*, found in TURN 22 Q 2 attachment 1. Page references refer to this document):

- PG&E has a huge percentage of its IT spend devoted to Application Development and Support (69%), compared with other utilities who have a median of 50% (p. 13).

---

[4] Data requests relied upon, such as the one referred to here, are found in Attachment 6.

[5] Calculated from PG&E- 2 chapter 9 Workpaper Table 9-5 (WP 9-3 to 9-22, electronic version).

- PG&E has a far larger proportion of AD&S full time employees (FTEs) engaged in development (76%) than other utilities in the study (p. 10). Other utilities have a higher proportion of their IT employees engaged in support than PG&E does.
- As a percentage of total revenue, PG&E's AD&S spend has been over 2.1% for the last 3 years (2009-2011, albeit improving from 2.5% in 2009), compared to other utilities with 0.54% to 0.78% of total revenue devoted to AD&S (p. 16).[6]
- PG&E has a depreciation cost of 17% of its AD&S budget, compared to other utilities with a median of 2% (p.9 and TURN 71 Q 3).
- PG&E spent $53.44 per customer on IT application development and support in 2011 (p. 7 and TURN 71 Q 1). Increases of the magnitude of 70% in such a cost every 3 years could obviously be problematic for customers.

PG&E justifies much of its IT request based on claims that the projects will improve safety, reliability, and customer service and satisfaction.[7] While these are clearly worthy goals if cost is no object, they must be carefully weighed against the requested IT expenditure of over $130 per customer per year.[8] In general we do not find the benefits commensurate with the costs, and will recommend reductions in IT programs as described below.

PG&E claims it has refined a new methodology for managing IT project delivery, which includes 4 Gate reviews designed to ensure that the IT projects are aligned to the goals of IT as well as the line of business (LOB), to set up the project for success, and to make sure the benefits are well defined and will be realized (PG&E-7, p. 8-24 to 27). However upon closer examination we find that (from TURN 22 Q 4 and 5):

---

[6] BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL

[7] These indicators are reflected in measures used in calculating STIP. See Testimony of John Sugar for TURN on the STIP program.

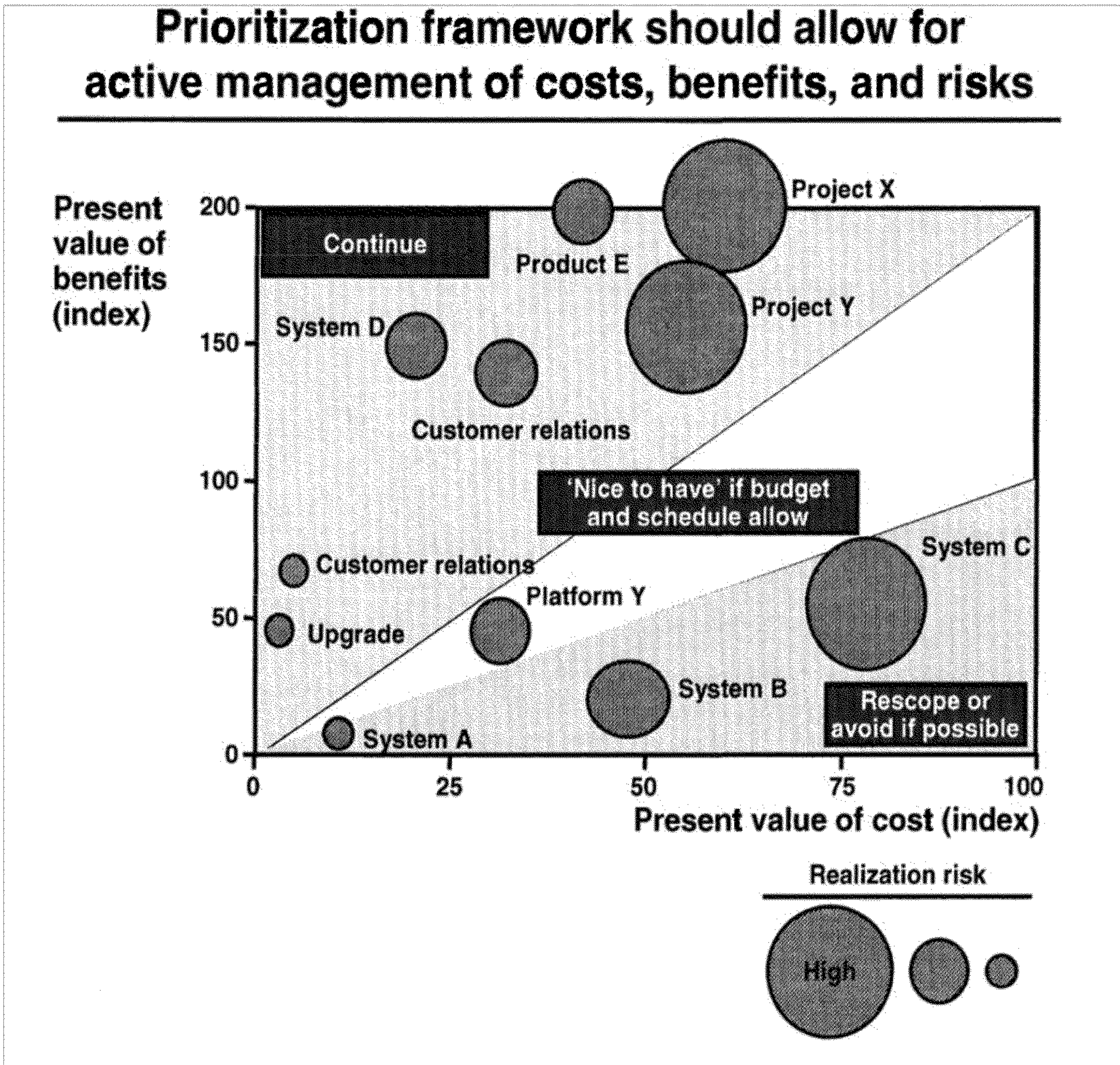
[8] Calculated as $820 million/6.1 million customers.

- PG&E doesn't require that costs equal benefits in order to approve an IT project, simply that whatever benefits are available have been documented. This constitutes "alignment" of costs and benefits according to PG&E's definition (TURN 22 Q 4a).
- Many of the benefits are qualitative in nature and thus not quantified, including those that increase public and employee safety, electric and gas reliability, customer satisfaction, and regulatory compliance.
- Many of the projects requested in this GRC were conceived prior to March 2012 when the new methodology was implemented, and thus they do not have status reports for Gate 3 (examination of "alignment" of costs and benefits prior to the "build" phase) or Gate 4 (confirmation of cost and benefits at the "deploy" phase).

It has been recognized for some time that PG&E's IT planning does not adequately emphasize project benefits and cost-effectiveness. The report from the Boston Consulting Group that PG&E presented in its 2007 GRC recommended that to move forward PG&E needs "enforced usage of PG&E business case; positive NPV required on any non-mandatory projects."[9] While PG&E's refined Project Delivery Method (PDM) is a step in the right direction, we are concerned with the lack of rigor in definition and "alignment" of benefits. Allowing most benefits to be "qualitative" and undefined then permits project costs far in excess of benefits and thus the galloping IT requests which we are repeatedly seeing in each rate case.

[9] Boston Consulting Group, A.05-12-002 (PG&E's 2007 GRC), Workpapers to PG&E 10, ch 4 vol 1 p. 23. Also WP to ch 10 vol 2, p. 1-87.

**Figure 1 Benefit/Cost Analysis of Projects**




Source: Boston Consulting Group, A.05-12-002 (PG&E's 2007 GRC), Workpapers to PG&E 10, ch 4 vol 2, p. 71.

As shown in Figure 1, projects with a benefit/cost ratio of less than 1 should be rescoped or avoided if possible. Projects with a benefit/cost ratio between 1 and 2 are "nice to have". Projects with a benefit/cost ratio greater than 2 should be continued. Unfortunately ALL of the IT projects PG&E is currently considering appear to fall into the lower shaded area with costs greater than benefits, similar to Systems A, B, and C in the figure above. According to PG&E's consultant, such projects should be rescoped or avoided.

Documents relied upon by PG&E show that benefit/cost comparisons among competing capital requests in a business are common, and that an economic justification is important, even for lifecycle projects (equipment and software replacement). The Gartner study, BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL. However at PG&E, we see no evidence of such hard tradeoffs among projects – rather the entire wish-list of lifecycle replacements as well as new projects is presented.

PG&E has tools to evaluate the benefits and costs of projects and business decisions. EASOP is an Excel-based economic analysis that calculates the after-tax cash flows from a project (TURN 53 Q 14). PG&E has generally not quantified the benefits from projects, however, so that this tool has not been applied to IT projects.[10]

Other examples exist of applying benefit/cost analysis to IT projects similar to those planned by PG&E. The Oregon Department of Transportation implemented nine IT projects with a combined benefit/cost ratio of 2.1, meaning that benefits of $2.10 were returned for every $1 invested in the projects. The nine systems include projects that are similar to those proposed by PG&E in this GRC, such as a Geographic Information System infrastructure (GIS), mobile data collection, engineering drawing, electronic document management system, construction engineering/inspection tool, and pre-construction assessment tool, among others.[11] PG&E's ratepayers need at least some similar assurance that the rate-funded projects will yield an appropriate level of benefits for the types of projects that PG&E requests here.

In many cases, PG&E is requesting funds in this GRC before the business case for the project is even prepared. For example, workforce mobilization business cases will be

---

[10] Aspects of the EASOP tool appear in analysis of reliability improvements using value of service calculations, for example TURN 32 Q 4 attachment 1.

[11] See Oregon Transportation Investment Act, *Information Technology Benefit-Cost Evaluation Report*. http://www.oregon.gov/ODOT/HWY/OTIA/pages/it_roi.aspx

developed later for each mobilization initiative (PG&E-4, WP 2-86). Other examples are the Outage Reporting and Analysis System Replacement (PG&E-4, p. 2-14); Disaster Recovery (PG&E-7, WP 8-162); the Data Historian project whose benefits will be estimated in 2014 (PG&E-4, WP 2-30); Records Management Archival project (TURN 75 Q 10); Scheduling Integration with Time Keeping Systems (TURN 80 Q 1) and others.

In fact, it appears to be part of PG&E's strategy in this case to identify costs but not to exert much effort at quantifying accompanying benefits. This might save the utility from embarrassment or hard questions if and when the projects fail to yield the expected benefits. In the 2011 GRC, PG&E did not realize benefits that were predicted from its Business Transformation IT initiative (a part of the 2007 GRC) and TURN recommended writing off that large expenditure.[12] PG&E's failure to estimate sizeable direct benefits for its major IT projects here might be explained as an attempt to avoid a repeat of the Business Transformation IT experience. On its face, PG&E's failure to quantify offsetting benefits before proposing a project is sufficient reason to deny funding. The strategy of "hiding the benefits" is neither a workable nor acceptable method for determining whether regulatory approval is appropriate for such projects.

We analyze PG&E's specific IT requests below. Absence of a discussion of any specific project should not be interpreted as our approval of that project.

## A. IT OWNED

By far the largest IT request is for the IT line of business, also known as "IT-Owned." This request, for $900.4 million in capital (MWC 2F in 2012-2016) and $719.5 million in expense (MWC JV in 2012-2014) (PG&E 7, WP 8-228 to 229) includes both Baseline systems (the preponderance of the expense request) and the Technology Reliability Portfolio (the preponderance of the capital request).

Some of this extra cost is brought on by the utility itself. PG&E quotes an article stating that the move from monthly meter reads to every 15 minutes will increase the data by

[12] A.09-12-020, Testimony of G. Schilberg, "Report on Information Technology and Various Electric Distribution Issues in PG&E's 2011 TY GRC," May 19, 2010, p. 4-5.

3,000 times (PG&E-7, p. 8-1) and thus the need for advanced IT systems to handle that data. However, this is an additional cost which was not articulated in the rush to adopt SmartMeters (and build ratebase).[13] It is questionable whether this additional data processing will provide a meaningful incremental ratepayer benefit. Even the promised benefits of SmartMeters have not been realized to date (see testimony of Mr. Jeffrey Nahigian for TURN as well as the lack of expected demand response benefits). Having been burned already by high SmartMeter costs without the full amount of promised accompanying benefits, we are reluctant to respond to further cries for funding for the consequences of a decision that was premised on the cost-effectiveness of this initiative.

As a benefit claimed for the Baseline portfolio, PG&E is proposing avoided annual labor costs of $16.9 million (due to reduced headcount), and $19 million per year due to lower per unit costs for delivering IT services (PG&E-7, p. 8-36). This represents 7.6% of the $474 million IT spend requested in 2014 by the IT LOB. (PG&E-7 WP 8-147 and 8-228). PG&E reduced its Baseline request by the amount of these avoided costs (TURN 75 Q 1).

PG&E also supports its request with reference to the operational efficiencies available from increasing mobile technology (PG&E-7, p. 8-2). While we are receptive to this line of argument if it is adequately substantiated, we note that the actual benefits are not quantified. Better inventory management and the more-informed decision-making that is made possible with the mobile devices needs to result in a benefit to ratepayers—otherwise it contributes to the IT treadmill (increasing costs which need replacement every 5-7 years) with any benefits (reduced costs) accruing to shareholders at least until the next rate case. If ratepayers are paying hundreds of millions of dollars in costs, ratepayers should see hundreds of millions of dollars in benefits, and those benefits should be reflected in rates at the earliest opportunity.

### *1. BASELINE*

The Baseline portfolio provides the infrastructure and support to completed projects in all lines of business. To the extent that disallowances are made to future IT capital projects requested in this GRC, a proportionate disallowance should also be taken for

---

[13] We note that residential SmartMeters, which are read every hour not every 15 minutes, increase the number of reads by 730, not 3000.

expenses in the Baseline function to support those reduced projects. TURN's capital disallowances for IT projects (across all lines of business) amount to a reduction of 25% of the capital requests. Therefore we reduce the Baseline expense request for support of those projects by 25% also, which equals a disallowance of $59 million in expense in 2014.[14] A similar adjustment may be appropriate for additional disallowances recommended by other parties.

### 2. *TECHNOLOGY RELIABILITY PORTFOLIO*

TURN agrees with DRA's recommendation to reduce each IT request that uses the Concept Estimating tool to 86% of the request. (DRA Ex. 18 p. 2).

*a. Lifecycle*

PG&E estimates its lifecycle replacement costs of equipment by determining the appropriate replacement period and the estimated cost of a replacement. (TURN 22 Q 12 attachment 1 and PG&E-7 WP 8-202). PG&E currently has in its inventory 31,300 computers, which it proposes to replace every 48 months. Valued at roughly $1400 per computer[15] to replace, PG&E adds a labor cost of 88% (or $1,232 per computer) as part of its replacement calculations. We object to this additional labor cost as excessive. At $140/hour this is an average of 9 hours of labor time, which we fail to see is necessary for each computer.[16] By reducing this factor by one third, to 58% of the average computer cost, the need for replacement goes from an average of $110.6[17] million per year in 2014-2016, to $107.9 million, a decrease of $2.7 million due to a lower estimate of the costs for lifecycle replacement of client computing.[18]

---

[14] Calculated as $240.9 million (from PG&E-7, WP 8-228) x 25%.

[15] Calculated from a system replacement cost of $43.688 million/31,303 units. TURN 22 Q 12 attachment 1 and PG&E-7, WP 8-202.

[16] BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL

[17] This amount covers replacement of datacenter technology, client computing, network and telecommunications, and security across the company. Calculated from TURN 22 Q 12 attachment 1.

[18] PG&E's budget includes far more than replacement of client computing, and also includes a cost reduction of 19% as an expected efficiency factor in lower costs for replacement technology.

*b. Disaster Recovery*

PG&E requests $96.6 million over 3 years (PG&E-7, WP 8-147) for an IT Disaster Recovery project that will develop and implement a disaster recovery program for PG&E's mission critical processes, including security and redundancy for essential systems and applications. PG&E's LOBs have identified a list of 17 "mission critical" processes that would be the focus of the Disaster Recovery project (PG&E-7, WP 8-161 to 162). The Disaster Recovery project BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL.

PG&E further explained aspects of the Disaster Recovery Program in response to a TURN data request. The mission critical processes have been listed in order of criticality, and processes numbered 1-8 deal with operations and safety and cannot tolerate down time (TURN 75 Q 6). Processes 9-17 can tolerate various amounts of down time, from 4 hours to 30 days.

BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL

BEGIN CONFIDENTIAL [redacted]

[redacted] END CONFIDENTIAL

There has been no benefit/cost analysis for this system, and not even any detailed documentation for the costs of this $96.6 million project.[19] PG&E acknowledged that architecture upgrades under this project will reduce the costs for integrating new applications and systems into the data center environment, but no estimate of savings was made. (PG&E-7, WP 8-167).

TURN's recommendation is to reduce the cost of this project by one half. The number of processes that PG&E classifies as mission critical is too extensive at this time. In order to minimize costs only the most critical safety processes should be part of this project now. Any future re-architecting of processes for Disaster Recovery should occur at the time of lifecycle replacement to further minimize costs. Disallow $18.5 million in capital in 2014, $22 million in 2015, and $9.4 million in 2016, as well as $1.6 million in expense in 2014.

*c. Telecommunications Network Enhancement*

In testimony PG&E states, "PG&E's need for telecommunications bandwidth is projected to increase by 300 percent over the next 5 to 10 years" (PG&E-7, p.8-51). The growth in telecommunications requirements is driven by the growth in automation infrastructure for gas, electricity (for example, SCADA), and generation; data security; video surveillance; customer programs (HAN, PHEV); and PG&E's mobile workforce (PG&E-7, WP 8-171 and WP 8-204). These end uses require more bandwidth than current capacity can provide beyond the next three years (capacity made up of PG&E and public carrier solutions) (PG&E-7, WP 8-169).

TURN believes that PG&E's expectation of 300% growth in bandwidth requirements over the next 5-10 years is overstated due to exaggerated planning for growth in Plug-In Hybrid Electric Vehicles (PHEV) and an excessive number of future workers with mobile capability. Both of these factors make up a significant portion of new bandwidth growth under PG&E's projections.

[19] PG&E recently identified that 85 software applications would be re-architected at an estimate of $600,000 each to support the 17 mission critical processes. (TURN 75 Q 5 attachment 1).

i. Reduction in Network Bandwidth for Mobile Workers

Of the approximately 5767 Mbps of bandwidth PG&E reports is needed for future edge network contributions to core network traffic, 3710 Mbps, or 64% is in support of an additional 1000 "Mobile Workers" (TURN 22 Q 15 Supp 1 Attachment 1). TURN is recommending a reduction in the increase of workers with mobile capability, allowing essentially one mobile unit per crew.[20] We adjust PG&E's estimate of an additional 1000 mobile workers down to an additional 400, thereby reducing future core bandwidth needs for mobile workers by 60%.

ii. Future Bandwidth Need for PHEVs is Overstated

PHEVs are expected to require bandwidth to monitor the battery charging unit status, to allow a vehicle to act as a distribution generator back to the grid, to provide capabilities for billing separate vehicle owners in multi-unit properties, and to monitor PG&E's electric transformers in response to the electric draw for the PHEV (TURN 80 Q 8). The latter use requires a constant monitoring bit stream.

When PG&E was asked to substantiate the projection of 750,000 PHEVs and the year expected, PG&E responded:

> *"This is based on research performed at the UC Davis Institute of Transportation Studies where they are projecting "the state will have 1.5 million zero-emission vehicles on the road by 2025."1 PG&E assumed 50% of this projection falls within the PG&E territory (750,000 PHEVs) expected over the next 10 years." (1 ITS, UC Davis Institute of Transportation Studies, March 2012, http://www.its.ucdavis.edu/?page_id=10964).* (TURN 51 Q 1 g)

In fact, the quoted text in PG&E's response is <u>not</u> referencing "research", but simply reports a "target" for ZEVs[21] (not just PHEVs as stated) to be in service in 12 years (by 2025 -- not 10 years as stated), as set by Governor Brown in an Executive Order of 2012.[22]

PG&E overstates the needed bandwidth requirements in the next "5 to 10 years" in several ways:

---

[20] See the additional discussion in Section II.B.10.c and the sections following.

[21] ZEVs include not only PHEVs but also hydrogen fuel-cell vehicles.

[22] See (2013 ZEV Action Plan, Governor's Interagency Working Group on Zero–emission Vehicles, Governor Edmund G. Brown Jr., February 2013, Appendix A citing Executive Order B-16-2012 of March 23, 2012. http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf

- Executive Orders of this nature are not a forecast of sales, and government actions to mandate ZEV levels have a poor historical success rate. We remember California Air Resources Board ZEV mandate of 1990 which required 2% of all vehicles sold be ZEV's.

- PG&E over-estimates the number of ZEVs in its service territory, even if the Executive Order's targets are met. PG&E's response assumes that 50% of the vehicles will operate in the PG&E service territory. This does not match with population percentages within the state and the PG&E service territory. PG&E provides service to approximately 15 million people,[23] while the United States Census estimates a statewide California population of 38 million.[24] This results in approximately 39% of the California population in the PG&E service territory, not 50% as PG&E projects.

- Given that PG&E's existing telecommunications capacity is adequate for the next three years, TURN supports a more conservative scenario for telecommunications capacity expansion in the short run, especially since it is driven significantly by PHEVs. It remains to be seen how widespread these vehicles will become, and whether the heavy bandwidth usage PG&E expects (monitoring transformers) is needed by every vehicle.[25] The Natural Resource Defense Council (NRDC) estimates ZEV sales in California in 2015 at a low of 40,000 and a high of 140,000.[26] We employ a lower scenario for the next few years of 50,000 vehicles sold per year in California. This "wait-and-see" approach appears more prudent at the moment.

PG&E provided the Excel model it used to determine an increase of 3.47 in future bandwidth needs (TURN_022 Q15 Supp 1 Atch01). We make the adjustments discussed

---

[23] http://www.pge.com/en/about/company/profile/index.page

[24] United States Census, http://quickfacts.census.gov/qfd/states/06000.html.

[25] Presumably this monitoring would only be required in neighborhoods with many PHEVs or where the transformer is already close to maximum capacity.

[26] S. Mui, A. Baum, *The Zero Emission Vehicle Program, An Analysis of Industry's Ability to Meet the Standards*, Natural Resources Defense Council, May 2010. http://docs.nrdc.org/energy/files/ene_10070701a.pdf

above to justify a maximum increase of 2.5 in the bandwidth requirements, or 70% of PG&E.[27]

We follow DRA's proposal to normalize the capital expenditures requested for this project over 3 years, and further adjust them by 70%.[28] Disallow $16.4 million in capital 2014, $7.9 million in 2015, and $7.1 million in 2016, as well as disallow $1.1 million in expense in 2014.[29]

*d. Records Management Archival*

PG&E proposes to spend $44.5 million in capital and $4.1 million in expense to create this records management system. This project builds upon funding from the 2011 GRC for the Documentum tool, which is now seen as not robust enough to handle PG&E's current requirements (PG&E-7, WP 8-182).

In the 2011 GRC PG&E requested funding for the Enterprise Content Management system, part of which includes this records management function (TURN 22 Q20). $13.7 million in capital has already been spent on this project, 2009-2012. (ibid). The additional functionality will make possible more efficient searching, classification of, and presentation of Documentum documents (TURN 22 Q 22).

Although PG&E expects that implementation of the system will reduce unit costs for storing and backing up electronic records to a level that is half of what they are today (PG&E-7, WP 8-186), no cost reduction benefits are attributed to this project. Subsequent information indicates that PG&E spent $10.7 million in 2012 for storage and backup costs (TURN 75 Q 9).

TURN recommends that this project be paid for by its benefits. We agree with DRA that no new funding should be provided for this project. If PG&E wants to install it, PG&E

---

[27] PG&E's workpapers, supplement 1, indicated a capacity increase of 3.5, and we have calculated 2.5. Our adjustments include 39% population adjustment, an allowance of 5% for non-electric vehicles such as hydrogen fuel cells, and a reduction to a 10-year rather than 12-year projection. TURN's estimate also includes the lower expectation for workers with mobile capacity.

[28] Capital normalized over 3 years = $33.4 million per year. 70%= $23 million per year.

[29] Calculated from PG&E-7, WP 8-174.

should pay for it out of the reduced document storage costs achieved in this rate case cycle, not with additional ratepayer money and the assumption that savings are zero.

Disallow capital expenditures of $16.5 million in 2014, $17.6 million in 2015 and $10.4 million in 2016, as well as $4.1 million in expense in 2014.

*e. Service Management*

PG&E requests a large amount of money ($26 million in capital over 4 years and $1 million in expense in 2014) to "develop and employ metrics" to measure the impact of IT reliability on business processes. This project is related to and will support the Disaster Recovery project (PG&E-7 WP 8-189).

As background it is worth noting that PG&E's IT systems are already operating with a high degree of availability (TURN 22 Q 9 attachment 1). No doubt as more statistics are monitored, performance will be further improved.[30] PG&E will not be developing metrics "from scratch," but rather will be tracking common IT and industry measures regarding IT downtime and cost to repair IT incidents (TURN 22 Q 17b).

One goal of this project is to use automation to reduce operational per unit IT costs by 20% in order to help offset cost escalation (PG&E-7, WP 8-189). However, when specifically asked, PG&E was unable to estimate the actual impact the Service Management project would have on the planned savings that will avoid escalation (TURN 22 Q 18a).

Part of the expense of this project is the development and mapping of application dependency (TURN 22 Q18). An example benefit of this in-depth mapping is the capability to identify the cause of an IT outage more quickly and deploy the right crew faster, because the application relationships will be clearer. Similarly, the urgency of repairing a server that goes down in the middle of the night can be ascertained and employee overtime avoided with the knowledge that the component is not critical to the line of business (TURN 22 Q 19 b2).

---

[30] The System Availability Index was developed in late 2011 so the benefits of monitoring this index are only beginning. (TURN 22 Q 9).

This is not convincing evidence of enough benefits to warrant the expenditure of $26 million. This project needs to be re-scoped to be in line with its potential benefits. TURN recommends $3 million in capital for a much smaller project to monitor IT health. Disallow the capital requests of $4.26 million in 2013, $5.86 million in 2014, $5.84 million in 2015 and $7.435 million in 2016.

## B. ELECTRIC OPERATIONS

The goals of the IT technology projects in the Electric Distribution LOB include "long-term benefits in terms of work productivity, efficiency and documenting compliance with legal and regulatory requirements by automating processes that are manually intensive..." (PG&E-7, p. 8-10). The IT Spend projected by the Electric Distribution LOB (including also the Workforce Mobilization Project for Gas Distribution) is $258.6 million for 2014-2016 (including both expense and capital, calculated from PG&E-4 WP 2-11 electronic version).[31]

PG&E attempts to incorporate productivity benefits via an offset to escalation. We find this method provides only a small proportion of benefits, as discussed in Section II.B.11 below.

### *1. DATA HISTORIAN*

The Data Historian and Alarming project ($25.2 million in IT spend from 2013-2016) (PG&E-4 WP 2-29) is a data archiving and analysis tool for use with PG&E's SCADA equipment. It will facilitate both real-time and historical analysis of the power system. PG&E presents its "Cost/Benefit Analysis" (PG&E-4, WP 2-29) but the table quantifies only costs. The benefits analysis will be conducted in 2014 (PG&E-4, WP 2-30).[32]

---

[31] Note that the electronic version of this table includes proposed expense entries for 2015 and 2016, which do not appear in printed workpapers. The authorized expenses for those years will of course be determined by authorized test year expense combined with attrition adjustments. When summing "IT spend" for the post test years, however, we feel it is more informative to include an estimate of proposed expenses, with the understanding that these values will be determined using another mechanism.

[32] PG&E claims this project may have a benefit in reducing the failure rates and frequency of outages due to failures in substation power transformers, circuit breakers, switches, reclosers, etc. (TURN 53 Q 2) but these benefits have not yet been quantified.

Since this project supports the SCADA system, its cost should be included in the benefit/cost analysis of those devices. PG&E is requesting not only this $25 million software project, but also a $28 million Platform Upgrade project to support SCADA (PG&E-4, WP 2-45). It is inappropriate to undertake the B/C of SCADA implementation without including the costs of the implementation software.

However we find that not only have these IT project costs not been included in a benefit/cost analysis of SCADA, but there has been no weighing of costs versus reliability and other benefits for the SCADA request at all.[33] This project has not been justified. DRA rejects this project (DRA Ex. 8 p. 58), and we support that recommendation on the basis of an absence of demonstrated benefits.

TURN recommends disallowing the following capital for the Data Historian project: $12.3 million in 2014, $10.9 million in 2015, and $0.98 million in 2016 (PG&E-4, WP 2-29). We also reject the expense of $0.2 million in 2014.

### 2. *CLOSED LOOP SMARTMETER OUTAGE MANAGEMENT INTEGRATION*

PG&E claims it needs to spend $5.8 million in capital on this system in 2015-2016 to integrate SmartMeter data into outage detection and response. Currently operators must manually integrate data from various sources to determine outages and direct restoration (PG&E-4, WP 2-37).

PG&E wishes to create a "closed-loop" system that automatically registers outages from the SmartMeters. However, storm damage can adversely impact the mesh network that communicates with the SmartMeters, "reducing the reliability and speed of outage notifications and restoration validation messages" (ibid.). We remember the nightmare scenarios caused by overwhelming outage ticket notifications produced in the 1995 storms[34] and caution that these automatic ticket notifications, combined with erratic communications networks, may not produce a desirable outcome. Furthermore in light of the fact that reducing unnecessary dispatch is a goal for storm rooms (TURN 10 Q 1

---

[33] See the testimony of Garrick Jones for TURN.

[34] See CPUC Docket A.94-12-005. Testimony of G. Schilberg, "The December 1995 Storm Response of Pacific Gas and Electric Company," on behalf of TURN. May, 1996, p.7.

attachment 1 p. 32 line 41), we question the wisdom of adding the automatic notification burden from SmartMeters.

PG&E alleges that these tools will reduce customer outage duration (PG&E-4, WP 2-40), but the benefits have not been calculated yet. As stated we expect the principal outage reduction to happen in the situation of "nested" outages in large storms, where a subset of customers may be subject to several outage causes (PG&E-4, WP 2-37). Since PG&E proposes to exclude large storm outages from its reliability reporting under the IEEE definition (see Section III below), its response time under ordinary circumstances will not be affected.[35]

We doubt that the benefit justifies this expenditure. TURN does not recommend funding this project in 2015 and beyond. Disallow $2.9 million per year in capital in 2015-2016. PG&E also requests $1.1 per year in expense in 2015-2016 for this project, which we also reject.

### *3. ADVANCED APPLICATIONS FOR DISTRIBUTION CONTROL CENTERS*

PG&E proposes to spend $9.5 million in capital in 2015 and 2016 for advanced applications for its distribution control centers. Features planned include a single user interface, so operators do not need to toggle between applications; suggestions for switching steps for operators; and a training simulator (PG&E-4, p. 2-18).

Benefits will be calculated later (PG&E-4, WP 2-34) but they will include improved and automated outage reporting. This project is a "nice to have" but the alleged benefits do not warrant this expenditure.[36] TURN does not recommend funding at this time. Disallow capital of $3.8 million in 2015 and $5.7 million in 2016.

Furthermore, this project is dependent upon the ED GIS/AM project (TURN 22 Q 5 attachment 9 p. 17). ED AM/GIS is not scheduled to be completed until the end of 2014,

---

[35] As discussed in Section III below, PG&E excludes performance on large storm outages from its reliability reporting under the IEEE definition.

[36] TURN's use of the "nice to have" label here does not connote a benefit/cost ratio between 1 and 2, as Boston Consulting recommended in Figure 1 above.

and its timeline has already slipped (TURN 53 Q 6). If DRA's recommendation to not fund the ED GIS/AM system is approved, then the future of this project is also in doubt.

### 4. *ELECTRIC DISTRIBUTION GIS AND ASSET MANAGEMENT*

PG&E's analysis of the Electric Distribution GIS/AM system appears to be representative of the lack of benefit/cost discipline at PG&E. The requested project, including 18% contingency,[37] is for $107.7 million in capital from 2012-2016 (through "Gate 3" of the project). It is to establish an integrated GIS/SAP system and provide a foundational platform to enable analytical and visual tools that will enhance Electric Distribution (ED) asset management and operations. The project includes conversion of legacy maps (PG&E-4, p. 2-23). Based on this platform many other projects are planned regarding workforce mobilization, outage operations, system planning, and reporting.

Documentation for the project (TURN 22 Q 5 attachment 9) notes the following:

- The major driver of this project is to improve safety, compliance and data integrity. While increased productivity and efficiency are possible, they are not the key drivers. (Business Case, TURN 22 Q 5 attachment 9, p. 9).
- Cost overruns have already occurred, increasing the projected cost from $97.1 million to $107.7 million through Gate 3.[38]
- The 2011 GRC request for a single GIS system has now been subdivided into 4 projects, one each for Electric and Gas distribution and transmission. (Business case, p. 5). This change was a result of a post-San Bruno assessment determining that more robust data quality was required. (PG&E-4, p. 2-26). Enhancements were made to the prior Automated Mapping and Facilities Management (AM/FM) project.

---

[37] Calculated as $16.1 million/$91.6 million total project cost. (TURN 22 Q 5 attachment 9 p. 3).

[38] Presumably the term "Gate 3" used here has a different meaning from the stage of the Project Delivery Methodology when benefits are aligned with costs. (PG&E-7 p. 8-26). In this Business Case "Gate 3" refers to another phase of the project (p.4).

- Maintaining the status quo was by far the cheapest solution (present value of revenue requirements of $12.8 million, compared to the proposed GIS/AM alternative of $88.2 million). PG&E recommended the GIS/AM alternative.
- The expected payback of the proposed alternative is "never" (Business Case, p. 15).

**Table 1: NPV of Alternatives Considered**

| Costs in (000's) | Cash Flow Measures | | |
|---|---|---|---|
| **Alternatives Considered** | **NPV** | **Payback** | **PVRR** |
| **Proposal (Expected Case)** | -52,316 | Never | 88,297 |
| **Status Quo** | -7,612 | - | 12,847 |
| **Alternative 1** | -50,580 | Never | 85,368 |
| **Alternative 2** | -53,951 | Never | 91,057 |

- The originally scheduled milestone dates have in general been delayed by 1 to 2 years (TURN 53 Q 6).
- A large part of the cost is a fixed-price contract with IBM for $42 million (TURN 22 Q 5 attachment 9, p. 12).
- The project anticipates a positive and indirect impact on earnings from operations (TURN 22 Q 5 attachment 9 p. 16).
- There has been a "fragmented system of legacy mapping" (TURN 22 Q 5 attachment 9 p. 18). Current data conversion is occurring in India (ibid, p. 8). The ED/GIS/AM project is a continuation of the previous AM/FM project (PG&E-4, WP 2-52).
- PG&E is estimating cost savings from ED GIS/AM of $0.6 million in 2014, $3.4 million in 2015 and $4.1 million in 2016, which have been included in the offset to escalation. (PG&E-4, p. 2-28).
- There is no Gate 4 status report (verification of costs and benefits) because this project purportedly started prior to March 2012 (TURN 22 Q 5 p. 4). However it

is notable that the Business Case analysis, TURN 22 Q 5 attachment 9, is dated July 26, 2012 (e.g. after March, 2012).

- PG&E has multiple large projects running in parallel with interdependencies (TURN 22 Q 5 attachment 9 p. 21). This creates a threat to the feasibility of accomplishing the project within the desired parameters (budget and schedule).
- Efficiencies are captured through capabilities enabled by GIS, not by GIS itself (TURN 22 Q 5 attachment 9 p. 22).

In TURN's view this project, especially when viewed in the context of the history of GIS attempts at PG&E[39] and the labyrinth of systems created by subdividing the original project into four,[40] does not inspire confidence that costs of this project will be contained and any benefits captured for ratepayers.

We also reflect that the need for a GIS system to support safety is probably larger with respect to the gas system than the electric system. The safety paradigm for gas assets requires data on the asset components for the length of their life in order to permit maximum gas pressure on lines. Since most of the gas assets are underground the spatial characteristics, as enabled by a GIS system, are an important component of this asset information. Also the integrity management program for managing the gas assets relies on a method of assessing threats through data-based inquiry. These aspects lead to a stronger case for a GIS system to support safety with respect to gas assets. For the electric system, on the other hand, where a larger proportion of the assets are above-ground and the system integrity is maintained via regular inspections, the need for a GIS-based system is less integral to the safe maintenance of the system. Since the safety rationale for a GIS-based system is less strong for the electric system, PG&E needs to rely on more efficiency and productivity benefits to justify this system for electric assets.

DRA rejected this project (DRA Ex 8 p. 57). In the alternative, if PG&E prevails in convincing the Commission that some level of funding should be provided toward a GIS

[39] PG&E spent $51 million in 2002-2007 to convert paper maps. (TURN 22 Q 23 supp 1) $17.4 million has been spent on GIS systems, 2009-2011 (DRA Ex. 10, p. 67).

[40] PG&E 3, p. 3-11.

system for Electric Distribution,[41] we recommend as a maximum the expected cost as shown in the business case ($91.6 million for 2011-2014). PG&E should be fully responsible for any contingency and cost-overruns. This is a huge financial investment in a foundational system, whose main purpose is to shield the Company from accusations by the Commission that it does not adequately support safety, compliance and data integrity.[42] We are not convinced that increased data accuracy and productivity will be achieved under this system.

TURN Recommendation: At a minimum, if PG&E refuses to quantify sizeable benefits before undertaking this large project, PG&E should be required to provide a full benefit/cost analysis after the project is completed (as done by the Oregon Department of Transportation cited above).

Furthermore we propose that expenditures for this ED-GIS project, combined with the numerous components of the Workforce Mobilization Project discussed below (for a total request of roughly $207 million in IT spend), be combined into a memorandum account capped at the expenditure levels proposed by TURN. After the projects are completed, PG&E must provide a combined ex-post benefit/cost analysis showing positive benefits (at least a B/C ratio of 1.0 over the combined projects) in order to obtain rate recovery of amounts recorded in the memorandum account. Part of the reasoning in our request for this benefit/cost analysis, albeit on an ex-post basis, is to require PG&E to critically assess the benefit of each aspect of the desired functionality of this project versus its cost. We recommend including only the functionality that provides the largest benefit for the least cost. Unless a strict benefit/cost discipline is implemented, each IT expenditure contributes to the IT treadmill.

### *5. OUTAGE REPORTING AND ANALYSIS SYSTEM REPLACEMENT*

PG&E requests $8.37 million in capital in 2013-2014 and $600,000 in expense over those two years for a replacement outage data management and reporting system. (PG&E-4,

---

[41] This will be on a different platform than the GIS system for Gas Distribution.

[42] The strategic objective is "to improve safety, compliance and data integrity by ensuring the accuracy and accessibility of critical asset records." Business Case, TURN 22 Q 5 attachment 9, p. 3. This is the influence of San Bruno felt in Electric Distribution.

p. 2-14 to 15). This project moves outage reporting out of CEDSA and into another platform based on the GIS/AM project (PG&E-4, WP 2-32.)

Not only have the cost savings not been estimated for this project (PG&E-4 WP 2-35) but also the costs of the alternatives have not been estimated (TURN 53 Q 4). The project is only at the "ideation" stage. TURN suggests that this program is not ready for prime time, should not be considered to be ready for completion in 2014, and could be rejected on that ground alone.

In light of delays of the GIS/AM project, the need for this outage system replacement may not occur on the expected timeline. The existing CEDSA system is well-liked and well-supported (TURN 22 Q 5 attachment 9 p. 12). We note that the status quo for GIS/AM and keeping CEDSA is a much cheaper alternative (TURN 22 Q 5 attach 9 p. 15).

Given the competing priorities and limits on available funding, TURN recommends disallowing this project pending its timeliness and PG&E's demonstration of the reasonableness of its costs in light of its benefits, as well as alternative approaches. Disallow capital of $3.3 million in 2013 and $4.5 million in 2014 as well as $362,000 in expense in 2014.

### *6. GRAPHIC WORK DESIGN TOOLS*

PG&E requests an IT spend of $12.4 million (2012-2016) for the Electric Graphic Work Design Tools project.[43] This is used for turnaround of work drawings and cost estimates to customers (PG&E-4, WP 2-62). It will be used for large New Business, Subdivisions, Rule 20, Reconstruction, Capacity/Reliability, and Work at the Request of Others (PG&E-4, WP 2-63).

Again, there are no quantified benefits, but the project supports more customer satisfaction, increased data integrity regarding distribution assets, and employee productivity by streamlining documents and estimates. (PG&E-4, WP 2-65).

---

[43] Note there is a separate Gas Graphic Work Design Tool request for $12.55 million (capital and expense, 2013-2016) (PG&E-3, WP 11-35.) This occurs because the Gas Operations has a different GIS system from Electric.

This project is dependent upon the ED GIS/AM project (TURN 22 Q 5 attachment 9 p. 17). ED AM/GIS is not scheduled to be completed until the end of 2014, and its timeline has already slipped (TURN 53 Q 6 and TURN 60 Q 12). This is a second-order project, and should not be approved until it is clear that the GIS/AM project has stabilized. Expenditures are already planned to keep the existing estimating tool (FFE) operational until it is appropriate to phase it out (PG&E-4, WP 2-64). We should not pay for two estimating systems at once. The need for this project is not urgent. TURN recommends no funding at this time.

Disallow capital of $2.9 million in 2013, $3 million in each of 2014 and 2015, and $0.3 million in 2016, as well as $0.8 million in expense in 2014 (calculated from PG&E-4 Workpaper Table 2-11).

### *7. SAP PLANT MAINTENANCE MODULE*

This five-phase project will serve as the SAP platform for workorder activity. No capital is requested in the test year, but the entire project entails an IT spend of $13.7 million over 2012-2016. (PG&E-4 p. 2-37 and PG&E-4 workpaper table 2-11.).

The most expensive phase of this project is Phase 5, Operational Reporting and Analytics, $4.6 million in capital in 2016 and $236,000 in expense in 2016. This project will evaluate the business need for an operational reporting and decision support system and develop reports/dashboards (PG&E-4 WP 2-74). TURN recommends no funding of Phase 5 of this project. Disallow $4.6 million in capital in 2016.

### *8. PROJECT MANAGEMENT AND REPORTING TOOLSET ENHANCEMENTS*

This request is for additional project management tools and analytic capability, costing $7.9 million in IT spend, 2014-2016. (PG&E-4, WP 2-76). This project is not urgent, and has no quantified benefits. TURN recommends no funding at this time. Disallow capital of $ 0.5 million in 2014, $6.19 million 2015 and $ 0.5 million in 2016, plus $ 0.5 million in expense in 2014.

### *9. CUSTOMER CONNECTIONS ONLINE (CCO) TOOLS (ELECTRIC AND GAS)*

Based on feedback regarding its New Business Process, PG&E proposes to revamp its customer-facing systems for new service requests. Specifically, deficiencies in dealing with service installation and modification, communications, and predictability of work timing were identified as problematic for customers (PG&E-4, p. 2-40 and TURN 53 Q 9). In order to improve this aspect of customer satisfaction, PG&E therefore proposes to enhance the Customer Connections Online Tools (CCO), with IT spending of $26.2 million between 2012 and 2016 (PG&E-4, Workpaper table 2-11, electronic version. $11.9 million of this sum is planned expense between 2012 and 2016.). Documentation substantiating this project (DRA 63 Q 8 attachment 2) requests only $12 million for this task, plus a $2.4 million contingency, to be spent in 2012-2013. $3.6 million has been funded for 2012 for this project (DRA 63 Q 8 attachment 2, p. 4). No justification has been presented for a $26 million project.[44] Although this project is currently in "Gate 3" analysis (DRA 63 Q 8), there are no quantified benefits to this project (Ibid, p.7), and it is primarily to enhance customer satisfaction.

This project serves New Business (and residential) customers and therefore should be paid for by the customers causing this expenditure. Similar to the principle behind PG&E's collection of new customer connection administrative costs (see PG&E-5, p. 4-35), any expenditures on this project should be paid for by a new <u>online administrative fee</u> which covers the costs incurred. Given the planned levels of expenditure, $26 million over 5 years or roughly $5 million per year,[45] serving an average of 37,300 online customers per year,[46] the charge per customer using the online system should be $134.[47]

TURN recommends no funding of this project by general ratepayers (disallow capital of $3.1 million in 2012, $ 0.83 million in 2013, $3.8 million in 2014, $3.2 million in 2015 and $3.2 million in 2016 as well as expense of $3.8 million in 2014). Any expenditure on this project should be paid for by a fee on the customers using this functionality.

---

[44] An earlier version of this project ($3.3 million) is described as the "Work Order Fulfillment" project, see DRA 63 Q 7 attachment 2.

[45] Because IT expenditures need to be renewed on a 5-7 year basis, it is not unreasonable to assume an ongoing $5 million per year for this functionality.

[46] Calculated as the 3-year average (2014-2016) of customers forecasted to use the online system from TURN 53 Q 10.

[47] Calculated as $5 million/37,300 customers.

Furthermore, we note the size of the charge which would be required to pay for the system, $134 per customer, demonstrates how grandiose PG&E's IT plans are. This project includes not only the minimum needs for better customer communication regarding project costs and timelines, but also non-essentials such as interconnection with municipalities to permit online showing of completed permits.[48]

The fact that the fee required to cover these outsized costs is probably four times what a tolerable fee[49] would be is consistent with the broader conclusion TURN believes the Commission should reach here: PG&E's IT plans are roughly 4 times the size of an appropriate system, where costs are more in line with benefits (judged by what customers would pay). The example of this CCO system also provides a telling indictment of the scale of PG&E's other IT requests, and supports our general conclusion that PG&E's IT costs are far in excess of commensurate benefits. PG&E's IT costs must be severely scaled back.

### *10. WORKFORCE MOBILIZATION AND SCHEDULING (ELECTRIC AND GAS)*

PG&E proposes to provide mobile technology and scheduling to its field crews in a phased-in project. This consists of workforce mobilization ($63 million IT spend, 2012-2016), a work scheduling and dispatch system consolidation ($30 million in capital and expense, 2012-2016), integration with time-keeping ($4.4 million spend 2012-2016), and Vegetation Control Application Replacement ($2.7 million). The total is thus $100 million in IT spend, 2012-2016. (PG&E-4, WP 2-15 to 16, electronic version).

BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL. In light of this changing environment, we are reluctant to invest $100 million for hardware and software which even in the best of cases would need to be replaced in 5-7 years (for another $100 million plus escalation) and is likely to become outdated even more quickly than that. Thus we

---

[48] This functionality is termed "municipality support."

[49] It's even questionable whether the average customer would pay $30 to use the online system, but we use this as the maximum fee level that may not engender substantial objection from users of the system.

counsel caution in PG&E's proposed complete rollout of mobilization to all field personnel.

PG&E has identified that it lags other utilities in mobile technology usage, and does not consider the status quo as an option. PG&E did not consider as a viable option either that only certain field crews or work types receive technology (PG&E-4, WP 2-93). This request is in addition to the funds spent on the prior 3 releases of MobileConnect projects.[50]

The workforce mobilization project is expected to increase productivity and efficiencies, conservatively estimated at $2.8 million in 2013, $5.2 million in 2014, and $7.2 million in 2015 (PG&E-4, WP 2-86 and WP 2-92 – calculated from the Mobile Connect Release 3 Business Case, plus expected benefits from mobilization of the Electric Compliance (GO 165) and Locally Headquartered (T-200) crews).

The Workforce Mobilization project is subdivided into components.

*a. Service Planners*

Regarding Workforce mobilization for service planners, PG&E requests a total of $12.9 million in IT spend for 2015-2016. This request purchases 948 units in two capital work orders (#5748014 and 5748081 (TURN 22 Q 1 supp 2, attachment 1). Initially PG&E stated that there are only 459 users among the mobile service planners shared between electric and gas (TURN 53 Q 13). However a revision clarified that PG&E has 825 personnel that need to use these laptops, as well as an allowance for spare devices of 15% (TURN 80 Q 3). It has not yet been determined if these ruggedized laptops will be a feasible replacement for the desktop computer used by the estimators (TURN 80 Q 2). Thus PG&E proposes that ratepayers pay for each estimator to have one desktop computer, one ruggedized laptop ($6000), plus 15% extra laptops in case one is non-operational. This is an example of the lack of frugality at PG&E, and the abundance of devices that are included with this request.

---

[50] Mobile Connect Release 3 was completed in 2012. The project designed, built and tested capabilities on the Field Automation System (FAS) for restoration troublemen, enabling work to be more efficiently dispatched via electronic work orders. DRA 63 Q 6 attachment 1. The features were also extended to GO 165 compliance inspectors in 2012 (PG&E-4, WP 2-8).

TURN recommends a belt-tightening adjustment of 20% reduction. Disallow capital of $1.3 million in 2015 and $758,000 in 2016.

*b. Scheduling Integration with Time Management*

Regarding the Scheduling Integration with Time Keeping, this project, at a cost $4.6 million, mainly has the benefit of saving some clerical labor. (PG&E-4 WP 2-99 to 100). Time card entry is now semi-automated for field workers, with administrative effort needed to enter the time sheet summaries into SAP. The number of clerical positions that will be saved has not yet been determined (TURN 80 Q 1). The benefit does not justify the cost of this project. TURN recommends zero funding for this project. Disallow capital of $1.75 million in each of 2015 and 2016. We also reject PG&E's expectation of $0.45 million in expense in 2015.

*c. Mobile Devices for Additional Crew (Electric and Gas)*

PG&E is requesting 1520 mobile devices for additional crew members. (TURN 22 Q 1 supp 2 attachment 1 and TURN 22 Q 1 attachment 15). This consists of 780 units for gas crews that have only received one mobile device for a multi-person crew ($ 5.6 million PG&E 3 p. 11-35), and 740 units for electric crews that have received only one device per multi-person crew ($5.4 million, PG&E-4 p. 2-55).[51] (TURN 80 Q 3)

Between the locally headquartered, general construction and substation crews (electric and gas) PG&E has 960 crews that are targeted for workforce mobilization (TURN 53 Q 13). PG&E plans to furnish a total of 999 units to those crews under its requested plan (calculated from TURN 22 Q 1 supp 2 attachment 1 by 2016). This is more than 1 device per crew. PG&E has failed to sufficiently demonstrate that net efficiencies will be obtained from adding additional expensive mobile units ($5,000-6,000 each) for an additional 1520 employees. TURN recommends zero funding for these projects. Disallow capital of $3.67 million in each of 2014 and 2015, and $3.56 million in 2016 (MWC 2F), plus expense of $325,000 in 2014 (MWC JV).

---

[51] We note that justification in TURN 22 Q 15 supp2 attachment 1 line 12 put the electric cost at $3.7 million, far less than the $5.4 requested for this project. Similarly the gas cost in TURN 22 Q 15 supp 2 attachment 1 line 20 was $3.9 million, far less than the $5.6 million requested in testimony. Those costs in TURN 22 Q 15 supp 2 attachment 1 were calculated at $5000 per device.

PG&E claims that additional mobile devices will enable data gathering in the field, thereby reducing the number of data handoffs and the likelihood of data input errors (TURN 39 Q 46). TURN believes that having more people with the ability to enter data (as opposed to having one mobile device per crew) could not only waste money, but could counterproductively make data management and quality control more difficult and expensive. Additional data inaccuracy could arise as 1) data from the field is input under difficult weather or environmental conditions, 2) data entry standards are not followed by all personnel, whose main task is equipment repair rather than data quality, 3) data is unknown by field personnel, and 4) contradictory data may be entered by several people working on the same job. TURN fundamentally is not convinced of the correctness of PG&E's unstated premise that multiple data entry points necessarily leads to more accuracy.[52]

PG&E also states that a virtue of mobilization is that field crews will have fewer paper-based processes that are prone to error (PG&E-3, WP 11-79). However electronic data is also susceptible to error. Absent significant data safeguards for quality control, a situation of "garbage in, garbage out" can easily arise, at considerable expense.

*d. Mobile Devices Replacement/Upgrade*

Although there has been some confusion in data provided by PG&E regarding additional mobile units requested[53] our latest information confirms that PG&E requests 780 additional mobile units for replacement/upgrade (TURN 80 Q 3). This covers field workers who currently lack the appropriate device, employees with damaged devices, and those with mobile phones at the end of their useful life. We assume this category is listed in PG&E-4 WP 2-88 to 2-89 as "Mobilization for Emergency Work Types" and "Automation of Clearance and Switching."

TURN disallows this expenditure. Employees with damaged devices are already covered by the 15% allowance for extra units in PG&E's estimates of number of devices

---

[52] The Oregon Department of Transportation study cited above (see footnote 11) discovered that inspectors found it impractical to fill out forms in the field using laptops and rather returned to the office to complete the forms. This meant that field data entry was less cost-effective than expected. (p. 24)

[53] Contrast TURN 11 Q 1 supp 2 attachment 1, TURN 53 Q 13, TURN 80 Q 3, and PG&E 4 p. 2-44.

for the mobilization project (TURN 80 Q 4). Workers who lack the appropriate device can be covered by PG&E's program that repurposes devices to appropriate uses (TURN 80 Q 5). Phones at the end of their life do not need to be replaced by $5000 units.

Disallow capital of $1.8 million in 2014, $6 million in 2015, $2.4 million in 2016, and expense of $440,000 in 2014.[54]

*e. As-Built Drawings*

Part of PG&E's plan for the workforce mobilization is to provide the facility in the field to research as-built records of equipment encountered on the site (PG&E-4, p. 2-45). This feature would supposedly enhance worker safety. Current mobile devices do not support such research (TURN 53 Q 1). We question how widespread is this benefit, and at what cost. There are, no doubt, some structures which are unique and non-standard (underground vaults, etc.) but we expect the majority of equipment encountered by crews on a daily basis is within a relatively narrow range of standard conditions. The cost of assembling and maintaining electronic data on as-built structures, however, is probably significant. The utility has existed more than a century without electronic as-built records, and we do not see this as a high priority for electric distribution. When necessary the as-built records can be acquired by crews in advance of their work, in the manner which they do at present. This may be another example of functionality which is nice to have but very expensive, and we encourage PG&E to pare its requests to the minimum best value.

*f. Summary*

For the Workforce Mobilization and Scheduling projects we summarize the following disallowances: capital of $5.5 million in 2014, $12.7 million in 2015, and $8.5 million in 2016. Disallow expense of 765,000 in 2014.

### *11. EFFICIENCY OFFSET OF ESCALATION*

The Electric Distribution LOB has committed to offset escalation for 2012-2015 via productivity improvements and other initiatives. This totals roughly $30 million in expense for 2014-2016 and $180 million in capital from 2012-2015 (PG&E-4, p. 20-6).[55]

---

[54] Calculated as the summation of Emergency Work Types and Clearance and Switching in PG&E-4, WP 2-88 to 2-89.

On the expense side this offset results in a reduction of roughly $10.7 million to requested 2014 (TURN 53 Q 15 attachment 1 and PG&E-4 WP 20-17). However we understand that after the TY amount is authorized in this GRC, attrition will be applied for 2015 and 2016. Thus this offset in effect reduces the test year expense (and implicitly post-test years) by $10.7 million each year, but normal attrition increases will apply going forward to authorized expenses.

The escalation offset was calculated as follows: each expense item was divided into its labor and non-labor components via ratios, and each component was escalated by yearly escalation rates from PG&E 10 ch 3. That sum of this escalation makes up the productivity benefit PG&E is claiming for its improvements and initiatives. The same method was used for capital.[56] This means that the productivity benefit for ED is a low 1.7% of the 2014 expense request[57] and 2.5% of the 2014 capital request for ED.

The claim that the escalation is representative of the productivity benefit is purely an assumption.[58] It could be (and hopefully will be) the case that efficiency benefits would be much more than the escalation in expense and capital.[59]

The expected efficiency improvements are not necessarily due to investments in IT. In fact the majority of predicted capital savings from the Electric Operations Improvement Plan are from analysis of shared costs and overheads[60] and from reviewing labor and contracting strategies.[61] IT investments may contribute to the expected expense savings of $10 million per year, but the return on IT investment that PG&E is planning is still

---

[55] No capital escalation offset was calculated for 2016 according to PG&E's methodology (PG&E-4 WP 20-18). The Electric Operations Improvement Plan absorbs escalation from 2012-2015.

[56] No escalation was attributed to MWC 2F (IT applications) or to parts of MWCs 06, 08, and 46.

[57] Calculated as 10.7 million / 631.1 million in expense in 2014 (PG&E-4, WP 20-17 line 40) and 43.66/1,770.06 million in capital in 2014 (WP 20-18).

[58] From TURN 10 Q 4, "There was no specific methodology PG&E used to determine that the goal to offset escalation was the appropriate estimate of the savings the Company would achieve."

[59] Actual capital savings for 2012 from the improvement program have been higher than forecast, although expense savings were less than forecast. (TURN 10 Q 3).

[60] Estimated at $91 million from 2012-2015, from PG&E's Electric Operations Improvement Plan, TURN 10 Q 1 attachment 1 p. 32.

[61] Ibid, estimated at $39 million, 2012-2015.

quite small. The projected IT spend for Electric Distribution is $350 million between 2012-2016.[62]

The costs that PG&E requests for its IT expenditures in Electric Distribution are vastly greater than the benefits PG&E is claiming. PG&E needs to achieve greater benefits or lower costs in order to align its IT expenditures.

## C. CUSTOMER CARE

PG&E is facing customer expectations for "anything, anywhere, anytime" (PG&E-7, p. 8-10), therefore PG&E proposes to "enhance customers overall user experience." But at what price?

PG&E claims its Customer Care IT expenditures are reasonable and fully justified because IT uses cost-effective technology offerings (PG&E-5, p. 9-2). PG&E clarifies, however, that "cost effective" is interpreted to mean that the project is complying with PG&E's long term goals of safe, reliable and affordable service. Apart from multi-year financial savings, "cost-effectiveness" also includes non-cost benefits such as customer satisfaction (TURN 50 Q 10). PG&E desires to provide service to customers through "personalized solutions in the channel of their choice," be it mobile, web, or live interaction (PG&E-5, p. 9-3). PG&E also notes that there is a cost to responding to the "increasing complexity of dynamic rate options." (PG&E-5, p. 9-3).

This LOB at least attempted to quantify benefits for the major software projects, although many benefits do not start until later years (2017 onward).

### *1. CUSTOMER INTERACTION AND RELATIONSHIP MANAGEMENT*

PG&E proposes to spend $37 million in capital (2014-2016) on this project, plus $3 million in expense in the test year. (PG&E-5, WP 9-60).

This project includes the "single view of the customer" (PG&E-5, p. 9-5) that was requested in the prior Business Transformation project. With this project CSRs would be able to avoid toggling over several applications and screens (PG&E-5, p. 9-6).

---

[62] Calculated from PG&E-4, WP Table 2-11 (electronic).

PG&E has identified $ 9 million per year in benefits from this system starting in 2017 (PG&E-5, WP 9-35 and 9-37), and expects also to increase customer satisfaction (PG&E-5, WP 9-32) and manage DSM programs more effectively (WP 9-36).

TURN recommends that this project be rescoped so that costs are more in line with financial benefits. Otherwise this contributes to the IT treadmill, requiring increasing ratepayer investments each refresh cycle for intangible benefits that are not even expected to arrive until after this GRC cycle ends.

Disallow the current project: capital of $12 million in 2014, $15 million in 2015 and $10 million in 2016, along with expense of $3 million in 2014 (PG&E-5, WP 9-34).

### 2. *INTERVAL DATA PROCESSING AND EXCEPTIONS MANAGEMENT*

PG&E proposes to spend $22.2 million in capital (2014-2016) on this project, plus $1.8 million in expense in the test year (PG&E-5, p. 9-10 and WP 9-60). The project will upgrade the meter-to-cash (MTC) architecture to better support work on prebilling exceptions and reduce the cost impacts of AMI software upgrades and fixes. We discuss two aspects of this project.

i. Need for Prebill Processing

Apparently PG&E is finding that the reams of electronic data that are produced by AMI are not necessarily more accurate than what existed before, at least not without considerable manual intervention to address data gaps and inconsistencies in the SmartMeter data. Pre-billing activity includes advanced validation, editing, and estimation (VEE), much of which is done automatically according to various data rules (addressing spikes and gaps, for example). However pre-billing situations that cannot be resolved automatically need to be worked manually. (This outcome, where considerable attention and effort needs to be given to data quality, causes us to be extremely cautious regarding PG&E's assertion that electronic data will provide more accuracy and net benefits than paper data, as PG&E alleges in its Electric and Gas Operations testimony. Not necessarily, in our view.)

Thus the hidden cost of AMI (and any move toward interval rates) is an alleged massive requirement ($18 million per year, for 188 FTEs PG&E-5 p. 4-17) to manually work the pre-bill exceptions for 4.5 million customers on an ongoing basis.[63] In the alternative PG&E proposes to spend $22 million in capital on this requested project to automate to a certain extent the prebilling exceptions, and to reduce somewhat the SmartMeter IT support costs.

Much of this projected effort is to process data that is not necessary and will not provide an incremental benefit. Currently PG&E only processes interval data exceptions on a manual basis for the 106,000 customers that are billed on interval rates (TOU customers) (TURN 50 Q 3 and Q 6). As part of this GRC PG&E projects the need to process interval data exceptions manually for an additional 4.2 million customers that are not currently on interval rates, and this perceived need is driving the request for 188 FTEs for prebilling processing as well as the request for the Interval Data Processing and Exceptions Management System. PG&E claims exceptions processing is needed for these customers, even though they are not currently on interval rates, because:

1. Utility rate analysis, system planning, and electric settlements depend on accurate underlying data;

2. In order to analyze customer rate options a full year of historical interval data is needed; and

3. If customers choose to enroll in MyEnergy (PG&E's website portal), it is impractical to retroactively resolve data exceptions so that a customer can utilize the rate option estimator. (TURN 50 Q 4)

We respond as follows to each reason PG&E presents above:

1. Rate analysis, system planning, and electric settlements can continue as they have for years without this level of detail and accompanying expenditure. Even if we assume that PG&E's proposal would achieve additional accuracy (a questionable assumption), there has been no demonstration that the additional accuracy is worth the extra cost.

---

[63] Not all of these employees are additional as release of 52 employees occupied with legacy requirements would mean only 136 are new hires. (PG&E-5, p. 4-18).

2. Customers of MyEnergy are already able to see analyses of different rates using existing data. Currently 2.5 million customers have enrolled in MyAccount (My Energy) (TURN 50 Q 1) and the status quo situation already offers these customers the ability to see their hourly usage and approximate bill analysis under different rate options.[64] The existing data is good enough for purposes of MyEnergy; additional manual processing is not needed for this purpose. Attachment 2 contains a sample of data already available on MyEnergy. Any minor improvements to those data are simply not worth millions of dollars.

3. Customers who enroll in MyEnergy already can view hourly data on their electric usage.[65] We do not see the need for additional prebill processing for these customers.

Thus we do not see the need for manual exceptions processing for an additional 4.2 million customers who are not currently on interval rates. Current data is good enough.

Furthermore because this function connects with billing, PG&E expects it to be in the new data center in a "high availability environment" with "disaster recovery and backup / restore of data" (PG&E-5, WP 9-44). PG&E has thus classified this as a "mission critical" system that needs to be "highly available," with few breakdowns. (See also Section II.A.2.b above discussing costs requested for IT Disaster Recovery). We disagree and maintain that prebilling exceptions processing for non-intervally billed meters is not a mission critical system. Extra expenditure does not need to be incurred for this level of criticality for non-intervally billed customers.

ii. Forecast Exceptions Rate

In the event that additional customers are billed under interval rates,[66] some additional manual processing may be necessary, but PG&E overforecasts the exceptions rate.

---

[64] The bill analysis is rounded to the nearest $5 or $10 as shown in Attachment 2; getting it to the nearest dollar will not influence customer decisions.

[65] A caveat on the data quality may sometimes appear, if there is a data gap or a spike, but that is acceptable for web presentment.

[66] PG&E forecasts only 98,810 customers to choose an optional rate which requires interval billing by 2014. (PGE-5, WP 4-30 line 8 note c).

PG&E expects additional customers to generate a much higher proportion of exceptions (0.9%) than existing TOU customers (0.2%) (TURN 50 Q 6, TURN 26 Q 2 attachment 1 tab 2f[67], and PG&E-5 WP 4-30). We see no support for 0.9% in the long run (TURN 50 Q 6),[68] as PG&E has been able to reduce the daily exception rate for TOU customers from 0.77% in 2011 to 0.21% in 2012 (TURN 26 Q 2 attachment 1 tab 2f), and those methods should also be employed to reduce exceptions from any future intervally billed customers. At the rate of exceptions experienced in 2012, the number of exceptions worked for all 4.5 million customers would then be 11,340[69] each year (2016 onward), one fifth of the figure projected by PG&E in support of its FTE requirements (calculated from PG&E-5, WP 9-47). This is a more reasonable maximum number of exceptions, in the event that all customers require interval billing. Thus rather than the 99 FTEs PG&E expects are needed for this function in the years from 2017 onward (calculated from PG&E-5 WP 9-47), the existing staffing should more than suffice.[70] This means that the 52 FTEs that are currently performing legacy meter exception work can be redeployed to provide one component of the net benefit that was expected under AMI, worth $5.2 million per year. (PG&E-5 p. 4-17 to 18 and TURN 50 Q 7)

iii. Conclusion

PG&E notes that if it remains on the existing platform, the prebilling exceptions would cost $10 million per year and technology upgrades roughly $1.5 million per year (PG&E-5, WP 9-44). For reasons discussed above we foresee the pre-billing exceptions cost to be closer to $2 million per year, one fifth of PG&E's estimate. It is not a reasonable use of resources to be devoting $10 million per year (as an actual cost or an avoided cost) to manual exceptions processing.

We note that the legacy system can be maintained for $3.5 million per year (PG&E-5, WP 9-47), and without the requirement for prebilling for non-intervally billed customers, PG&E's request for prebilling exceptions can be further reduced to $2 million per year.

---

[67] The daily rate of exceptions was 0.21%, averaged over 2012.

[68] PG&E claims the exceptions rate will not increase (PG&E-5, WP 9-46).

[69] Calculated as 4.5 million meters x 12 months x 0.21% exceptions.

[70] PG&E had an average of 30 FTEs working on this function in 2012. (TURN 26 Q 2a).

PG&E has failed to establish the need for manual prebill exceptions processing for an additional 4.2 million customers (PG&E 5 ch 4) or for this expensive IT solution to process prebilling exceptions.

Without the illusion of savings from prebilling exceptions, this project is not cost-effective (spending of $22 million to save $3.5 million per year).

TURN recommends that PG&E rescope this project as a lifecycle replacement at the appropriate time (when replacement costs are less than costs of upgrades), and minimize the functionality to reduce cost. Waiting to implement such a project is also more prudent, because forthcoming rate design decisions may shed further light on the need for and requirements of such systems.

Disallow capital of $20.7 million in 2014-2016.[71] Disallow capital of $15.5 million in 2014, $3.7 million in 2015, and $1.5 million in 2016. Authorize $2.8 million per year in expense to fund the existing platform. (PG&E requested $1.8 million in expense for the new system, which we reject. PG&E-5 WP 9-60).

### 3. *OPTIMIZING TIME TO MARKET RATES*

PG&E proposes to spend $12 million in capital (2014-2016) on this project. (PG&E-5, WP 9-60). This software supports more complex rates, including supporting a definition of a "customer" as mobile (electric vehicles, prepaid energy cards, etc.) rather than attached to a "premise." Such a feature will support a move to point of purchase pricing.

This project may be "nice to have" but appears to be non-essential at the moment, with no quantifiable benefits. TURN recommends no funding at this time. Disallow $6 million capital in 2015 and $6 million capital in 2016. This project is associated with an expense of $1 million in each year 2015 and 2016 which we also reject.

## III. MEASUREMENT OF ELECTRIC RELIABILITY

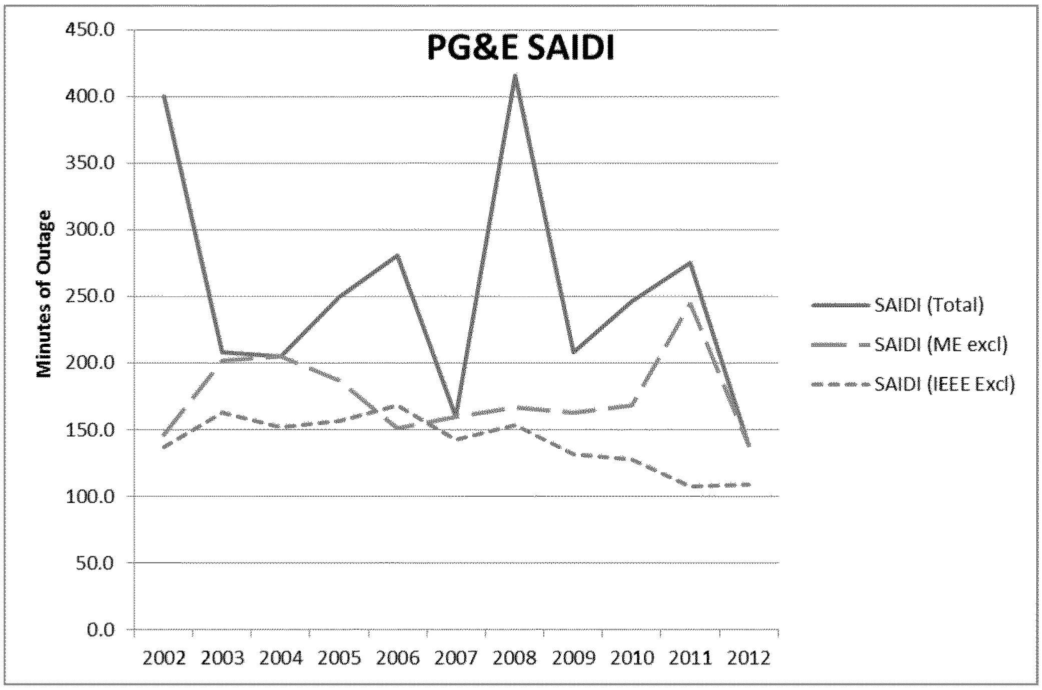
PG&E claims its electric transmission and distribution reliability is improving (PG&E-4, p. 15-5 to 15-8), however the true picture is more complicated. As shown in Figure 2, the

---

[71] Calculated as $22.2 million for the Interval Data Processing and Exceptions Management Project, less $0.5 million per year in capital for the existing system (PG&E-5, WP 9-47).

total duration of outages (the solid line) each year can vary, depending often on large weather-related events. The figure depicts SAIDI (System Average Interruption Duration Index), the per-customer index of outage duration.

Figure 2: **PG&E's System Annual Interruption Duration Index (per Customer)**




Source: PG&E, 2011 and 2012 Annual Electric Distribution Reliability Report (D.96-09-045 and D.04-10-034), Tables 2, 3, and Table A. Also TURN 4 Q 7b, TURN 32 Q 2.

Two different definitions have been employed to exclude outages caused by major event (ME), representing events beyond the utility's control, in order to obtain a clearer picture of what the underlying reliability is under normal circumstances. These definitions provide very different interpretations of PG&E's current reliability, as shown above. Under the definition of exclusions provided in D.96-09-045 ("SAIDI ME excl" in the figure above), reliability worsened through 2011 and no major events occurred in 2012.[72] Under the definition provided by the IEEE 1366-2003 standard ("SAIDI IEEE excl" in the figure above), reliability is improving (fewer minutes of outage) and there were

[72] Under D.96-09-045, an event is classified as "major" if a) the event is caused by earthquake, fire or storms of sufficient intensity to give rise to a state of emergency being declared, or b) it affects more than 15% of the system facilities or 10% of the customers.

excludable events in 2012. Thus the two definitions of major events provide different conclusions with respect to what is happening with PG&E's reliability under normal circumstances.

A full understanding is needed of whether the large MEDs are caused by worse-than-average weather, inefficient response on the part of PG&E, or other factors. Under the IEEE definition a slow response by PG&E to an average event could cause it to be classified as an MED. Is the "improvement" in PG&E's "normal" reliability, as viewed under the IEEE definition, caused by slower storm response and thus more events classified as MEDs?

**A. IEEE DEFINITION**

PG&E and the electric industry now favor the method created by the IEEE (Institute of Electrical and Electronics Engineers) to identify and classify outage data for purposes of reporting. The IEEE definition, created in 2003,[73] relies on a statistical analysis to identify outage events that appear to be "outliers," where the event is therefore assumed to be beyond the utility's operational and/or design limits. On the assumption that daily outage response is normally distributed,[74] a cutoff value of SAIDI can be calculated which separates "major events" from other events. It was determined that identifying observations outside of a statistically calculated value (termed Tmed)[75] created a reasonable definition of "major event," because in practice such a demarcation was expected to exclude roughly 2.3 days per year.[76] Under the IEEE definition it was

---

[73] Although published formally in 2004, the standard is referred to as "IEEE 1366-2003."

[74] The distribution of the natural logarithm of the daily SAIDI observation is therefore assumed to follow the normal distribution. Implicitly there is also an assumption that outage response on each day is independent of response on other days.

[75] The cutoff value, termed "Tmed" is calculated from the natural logarithm of the daily SAIDI data as a function of the average plus 2.5 standard deviations, calculated over (preferably) 5 prior years of data. "MED" denotes "Major Event Day."

[76] Cheryl Warren, James D. Bouford, Richard D. Christie, Dan Kowalewski, John McDaniel, Rodney Robinson, David J. Schepers, Joseph Viglietta, Charlie Williams, "Classification of Major Event Days, 2003, http://grouper.ieee.org/groups/td/dist/sd/doc/2003-01-Major-Events-Classification-v3.pdf. See Attachment 3.

emphasized that no data is <u>excluded</u>, but rather events are classified into two groups—normal performance and outage performance under abnormal conditions.

## B. THE IEEE DEFINITION AS APPLIED TO PG&E'S DATA

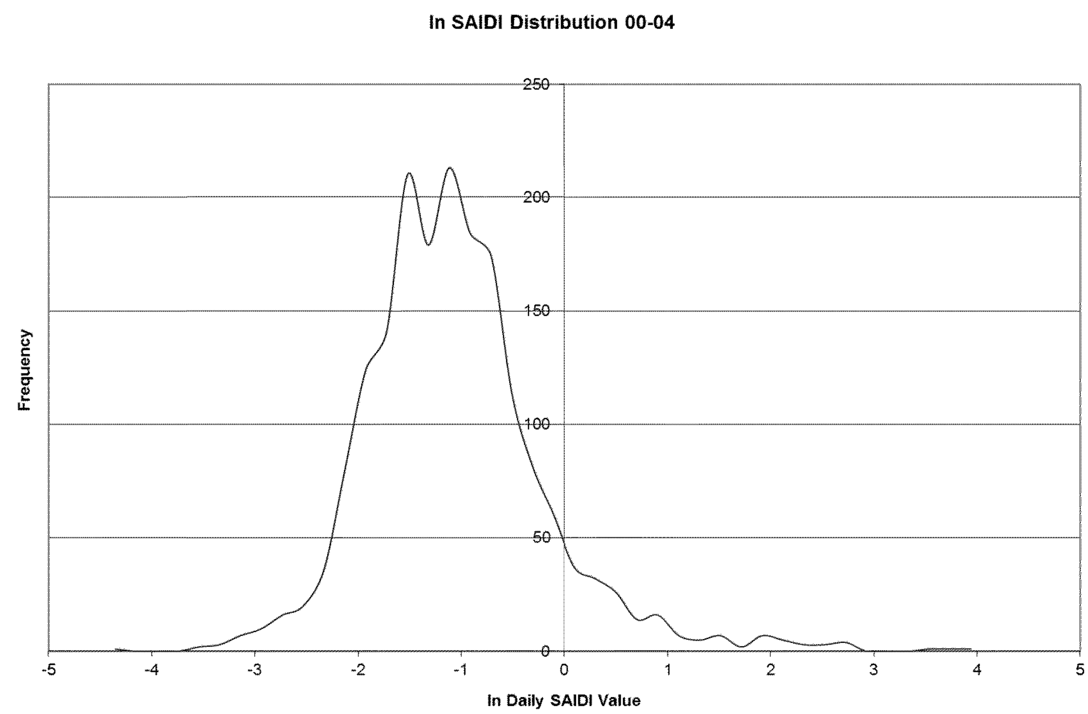
### *1. PG&E'S DATA DOES NOT FIT THE IEEE ASSUMPTIONS*

In several respects the application of this definition to PG&E's data has created results which are increasingly out of alignment with the original intent of the definition.

*a. Outage Distribution is not Normal*

PG&E's outage data does not exactly fit a log-normal distribution. Figure 3 shows the distribution of the natural logarithm of the daily outage duration, over a 5-year period. Note that the observations in the right hand tail of the distribution (the area from 1 to 4 on the horizontal axis) are not smoothly conforming to an expected normal curve.

**Figure 3: Daily SAIDI, Natural Log Distribution, 2000-2004**




Source: TURN 4 Q 11 attachment 1.

When TURN requested the data underlying PG&E's assertion in AL 3812-E that the IEEE definition of major event days correlated with extreme outlier days better than the

ME criteria in D.96-09-045, PG&E had no specific analysis that made that conclusion. Rather, PG&E presented graphic examples of cumulative daily outage distributions (TURN 4 Q 11, see also Figure 4). PG&E states that the data response shows that the lognormal distribution is the best fit of the five distributions tested. While that may be the case, that conclusion is not the same as proof that the IEEE definition of major event days is suitable or better than the criterion in D.96-09-045.

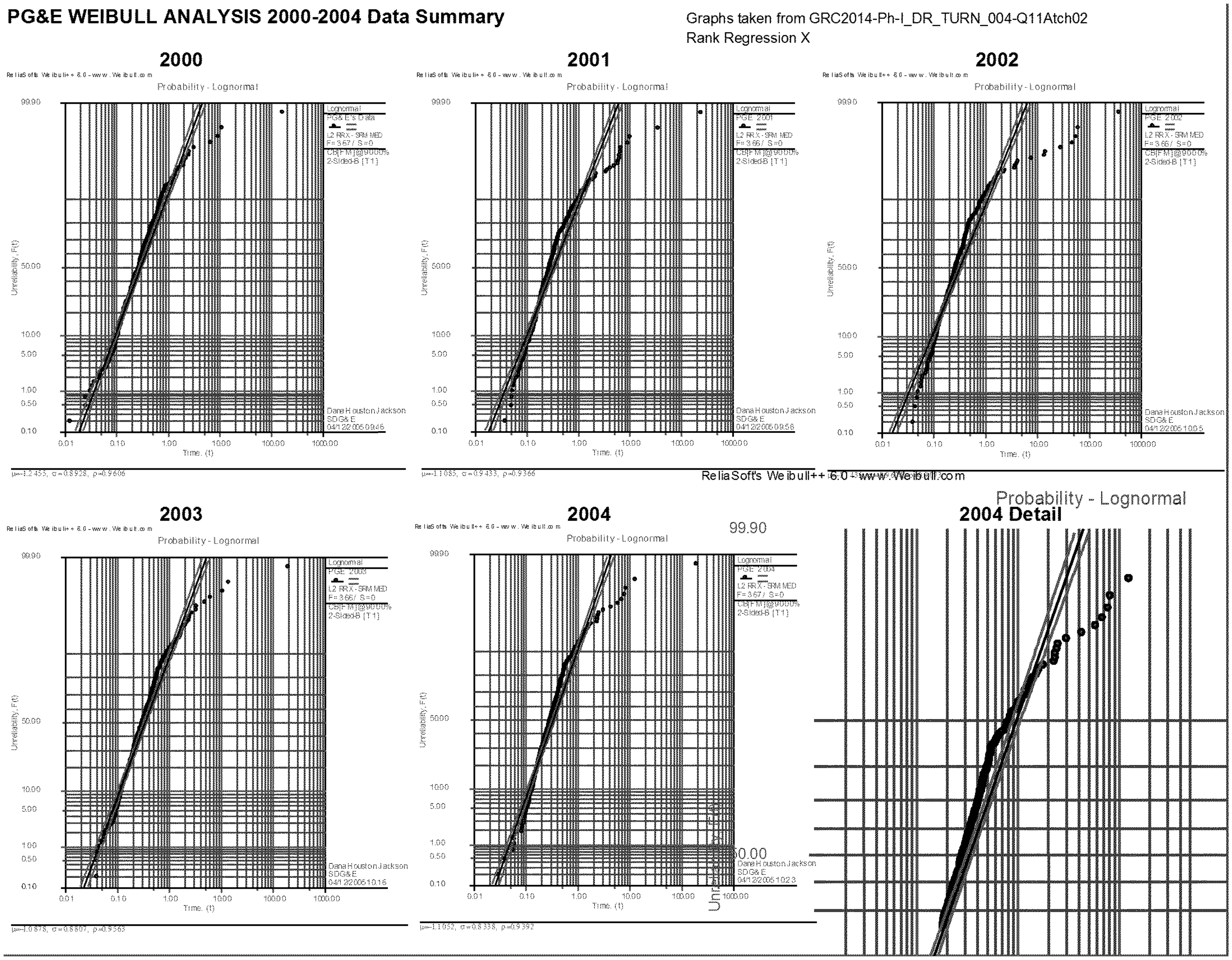
Rather, we note that it is in the right-hand tail of the distribution (the large outage events) where the lack of log-normal fit is most apparent (because the observations do not fit the straight line in the diagram below).[77] In the past PG&E has admitted that the distribution of SAIDI data does not perfectly fit a log-normal distribution.[78]

---

[77] These are cumulative probability plots of the natural log of PG&E's SAIDI data and the normal curve. If the fit were perfect, the points would line up along the straight line (representing the normal distribution).

[78] See A.08-05-023 (Cornerstone), TURN 3 Q 1b.

**Figure 4: Log-Normal Distribution Cumulative Probability Plots, PG&E Daily SAIDI, 2000-2004**



We quote from the paper by Richard Christie which was the seminal statistical work that underlies the choice of the IEEE definition:[79]

> *One note of caution is that the statistical method presented here relies on evaluating small probability values in the extended tails of probability distributions. In the statistical method, the tail is determined by the fit of the entire distribution. A good fit for the distribution may not be all that good for the tail. The major reasons to believe that the fit to the right hand tail is good are (a) the good match to linearity in the probability plots of the sample data of the high historical reliability days, and (b) the intuitively satisfactory classification results obtained using the method. Both of these depend on the nature of the historical data. Data from a larger number and a wide variety of utilities should be examined before drawing final conclusions about the proposed classification method. (p. 15)*

It appears that PG&E's data for these available years do not meet criteria a), because especially the right tail events do not follow the log-normal distribution as shown in Figure 4. We examine criteria b) in the comments below.

*b. Daily Performance is not Independent*

In situations of multi-day weather events, the assumption that the outage performance in each day is independent of the other does not hold. This is one way in which the distribution of outage performance deviates from the original statistical assumptions. We note that the majority of the "major event" days (MEDs) excluded by PG&E under the IEEE definition are consecutive, as shown in Table 2 below. Over the ten years of data shown, where PG&E classified on average 8.1 days of MEDs each year (far more than the 2.3 intended), on average 3 MEDs each year were due to consecutive weather events; five MEDs on average each year were due to non-consecutive (unique) events.

[79] Richard D. Christie, "Statistical Classification of Major Reliability Event Days in Distribution Systems, August 8, 2001. (See Attachment 3: IEEE Articles)

**Table 2: Number of Major Event Days for PG&E under IEEE Definition**

| | *Total MED* | *Non-consecutive MEDs (unique)* | *Consecutive MEDs* |
|---|---|---|---|
| 2002 | 11 | 4 | 7 |
| 2003 | 6 | 5 | 1 |
| 2004 | 7 | 7 | 0 |
| 2005 | 8 | 7 | 1 |
| 2006 | 10 | 6 | 4 |
| 2007 | 3 | 1 | 2 |
| 2008 | 7 | 4 | 3 |
| 2009 | 5 | 5 | 0 |
| 2010 | 10 | 4 | 6 |
| 2011 | 14 | 8 | 6 |
| Average | 8.1 | 5.1 | 3.0 |

Source: calculated from TURN 4 Q 7b

According to the IEEE conventions, interruption durations that span multiple calendar days accrue to the day on which the interruption began.[80] PG&E follows IEEE practice (TURN 32 Q 5). However the fact remains that for storms spanning several days, the outage performance on a given day is not independent of the performance on prior days.

*c. Major Event SAIDI is Very Large*

A study of various utilities found that SAIDI under the IEEE Standard was roughly 11% lower than total SAIDI (unadjusted for MEDs).[81] For PG&E, the IEEE value is lower by far more, on average 39% lower than the unadjusted total SAIDI.[82] This indicates that major event days are a significantly greater proportion of PG&E's overall outage response than other utilities' overall outage response. Conversely, exclusion of these MEDs from PG&E's reliability statistics (to arrive at "normal reliability") makes a far greater change in the resulting reliability data than it does for other utilities. By excluding the major event data, the total exposure of PG&E's customers to loss of power is vastly understated.

---

[80] Warren ibid., p. 2.

[81] Joseph H. Eto, "Update on DOE-Sponsored LBNL Reliability Research," July 26, 2011, p.11. See Attachment 3: IEEE Articles.

[82] Calculated from data covering 2002-2012 from PG&E's Annual Reliability Reports.

The result is not "intuitively satisfactory" in TURN's view, as required by Christie, quoted above. The following recent examples demonstrate some of our concerns:

- In 2011 the SAIDI representing "normal" circumstances according to the IEEE definition, 107.4 minutes in 2011, excludes far more outage time (168.3 minutes from MEDs) than it includes. The reliability under "normal" circumstances, 107.4 minutes, is VERY different from what customers as a whole experienced, 275 minutes in 2011. PGE admits "... customers' experience of an outage is the same whether PG&E categorizes the cause of that outage as a major event or non-major event..." (TURN 12 Q12).

- In 2012 when no major event day occurred according to the definition provided in D.96-09-045, under the IEEE definition 30 minutes of SAIDI were excluded due to MEDs, or 22% of the total. This is double the 11% reduction experienced on average by utilities, as cited by Eto above.[83] Although we have not yet ascertained which days were excluded under the IEEE definition, we are concerned that smaller events are being excluded as a result of the IEEE definition.

- We note with concern that the number of MEDs appears to be increasing. In prior testimony, we calculated an average of seven MEDs per year for the period 2004-2008 for PG&E under the IEEE definition.[84] Here, over the period 2002-2012, it appears there is an average of 8.1 MEDs. Both statistics are far greater than the design number of MEDs, or 2.3 days per year.

*d. Conclusion*

Our conclusion from the above data is that the IEEE definition for PG&E does not work well. (This echoes our conclusion made in a prior case, where we recommended altering the IEEE definition to 3.6 Beta, rather than 2.5, for use by PG&E.[85] We are not making such a recommendation again here.) Referencing the quotation of Christie above, we see

[83] See Footnote 81.

[84] A.08-05-023, W. Marcus and G. Schilberg, Report on PG&E's Distribution Reliability Improvement Program, for TURN, July 17, 2009, p. 102. Extract available in Attachment 4.

[85] Ibid.

that PG&E's data illustrates exactly the caution "a)" that he raised – that the distribution of reliability data, especially on the high-value days, does not follow a log normal distribution. Christie's caution "b)" also fails because the results produced are not intuitively satisfactory. Thus any use of the IEEE definition for PG&E data must be exercised with extreme caution.

PG&E believes that using the IEEE 1366-2003 definition is more statistically accurate (TURN 4 Q 9). However we have seen that the statistical assumptions upon which this conclusion is based are not met in PG&E's case. Log-normality is not met, especially in the right tail. Independence of each day's outage performance is not met for PG&E, especially for major event periods. Furthermore we note that the number of MEDs is increasing over time, and Tmed appears to be decreasing over time (TURN 4 Q 7e).

### 2. *REGULATORY CONCERNS*

PG&E notified the Commission in AL 3812-E of its intent to report only outage data according to the IEEE definition -doing away with the prior major events exclusion definition under D.09-09-045. Several aspects of this Advice Letter and notification concern us:

- PG&E requested and was granted permission to report only outages under the IEEE 1366-2003 definition.[86] It is not clear whether PG&E will continue to report the total outage statistics, <u>inclusive</u> of IEEE major event days. Response to TURN 32 Q 6 indicates that PG&E agrees with the IEEE recommended guidelines that outages excluded from reporting under the IEEE 1366 definition (e.g. the major event days) should be reported and analyzed separately, but this needs to be clearly stated in a Decision on this matter.
- Notification of this change via Advice Letter, whereby total outages would no longer be reported, was not made to the service list which has deliberated these definitional issues, nor to the parties on the service list of D.96-09-045, but rather to the GO-96-B, Section IV list. (TURN 4 Q 11). TURN and JBS Energy are not on

[86] "after which time [3 years hence, ed.] the Company will only report the IEEE 1366-2003 calculation." AL 3812-E. March 7, 2011.

the GO 96-B service list and were not aware of the opportunity to comment on this topic.

- IEEE policy and guidance is that the major event outages be separately analyzed.

> *It is anticipated that both executives and regulators will scrutinize those events that cause MEDs and take appropriate action to mitigate their future impact on reliability.*[87]

> *It is the group's recommendation that major event day performance be reviewed in a direct, possibly more rigorous, manner than normal day performance.*[88]

The Commission needs to require such reporting and analysis. It is best if it is made very clear in a decision that PG&E is required to report on total outages and to analyze its major event performance. Our preference is to see a) total outage statistics, b) outages excluding MEDs, and c) an analysis of MEDs, similar to the annual reporting PG&E currently does.

### *3. CONCERNS REGARDING USE OF THE IEEE DEFINITION*

In addition to the above concerns we encourage further caution in use of the IEEE definition for the following reasons:

- A mechanistic application of this definition could easily exclude major outages due to utility-caused events – for example the electric equivalent of the San Bruno explosion.

- Many smaller events are considered as MEDs using the IEEE definition. Some even appear to be within the system design criteria.[89] (See Table 3). We are especially concerned to find "major events" excluded due to equipment failures (transmission relay), dig-ins, the "first rain of the season," and events which didn't even make the list of the most important 10 outages of the year.

---

[87] Warren et al, ibid. p. 2. See Attachment 3: IEEE Articles.

[88] Ibid., p. 3.

[89] The system is generally designed for wind speeds of up to 55 mph.

**Table 3: Selected "Major Event Days" of Concern under the IEEE Definition**

| Date | Description | # customers Affected | SAIDI |
|---|---|---|---|
| 12/28/2003 | Not on list of largest 10 events in 2003 | 24,201 | 5.2 |
| 10/1/2004 | Third party dig-in to a transmission line in De Anza division | 58,591 | 4.7 |
| 10/8/2005 | Not on list of largest 10 events in 2005 | 45,469 | 3.1 |
| 3/20/2005 | Rainy and blustery with gusts up to 45 mph | 69,774 | 3.1 |
| 9/20/2005 | Lightning in the Bay Area | 110,226 | 4.3 |
| 11/20/2005 | Transmission relay malfunction (Moraga-Oakland Station X) | 116,513 | 4.6 |
| 2/26/2007 | Gusts up to 45 mph; rainfall below 1 inch | 82,763 | 3.4 |
| 10/4/2008 | First rains with gusts of up to 44 mph; flashover incidents. | 99,720 | 3.8 |
| 10/24/2010 | Early season storm; Redding wids of 49 mph; Santa Rosa 4.75" rain | 110,862 | 3.8 |
| 11/22/2010 | Not on list of largest 10 events in 2010; followed a 2-day event | 20,680 | 3.7 |
| 9/10/2011 | Thunderstorms in Fresno and Kern divisions. 3833 lightning strikes in Kern Division. | 77,443 | 3.0 |
| 10/5/2011 | Moderate southerly winds and heavy rain. Central Valley Region outages due to pole fires/flashover caused by the first rain after months of prolonged dry weather. | 100,357 | 3.0 |

Source: TURN 4 Q 9 and PG&E's 2011 Annual Reliability Report.

- Many of these events affected a relatively small number of customers. Remembering that the major event criterion under D.96-09-045 concerned 10% of customers out (which for PG&E would be around 500,000 electric customers), categorizing events with 100,000 customers or less as MEDs appears to classify too many in this category. This data seems to contradict PG&E's assertion in AL 3812-E that the IEEE definition of major event days correlated with extreme outlier days better than the ME criteria in D.96-09-045.

- The reliability indicator excluding MEDs as defined by IEEE is proposed as a component for use in calculating executive bonuses under the STIP program (TURN 4 Q 14 and TURN 32 Q 2).[90] We cannot accept rewarding executives for reliability when MEDs are increasing, numerous questionable events are excluded as MEDs, and storm performance has not been analyzed.

---

[90] Planned outages would be included in the STIP reliability component.

- The IEEE Benchmark study in 2010 identified a task to consider data which helps the industry back into a scorecard for evaluating storm performance (TURN 32 Q 1). No industry scorecards have been created, however. PG&E has no method in place for comparing storm performance either, but suggests six possible metrics for measuring and analyzing response (TURN 32 Q 1d). A plan to analyze performance on MEDs must be implemented, and should be made a component of the annual reliability reporting to the Commission.

## C. RECOMMENDATIONS

TURN recommends extreme caution in interpreting PG&E's outage statistics that result from the IEEE definition. PG&E's data do not fit the assumptions required to make this definition a valid method for excluding major event days. TURN therefore makes the following recommendations:

- PG&E should continue to report total outages, including MEDs, in its annual report to the Commission. The report should contain a) total outage statistics, b) outages excluding MEDs, and c) an analysis of MEDs.
- PG&E should recognize that the IEEE method of classifying MEDs does not work well for PG&E's data and that this is not a "gold standard" that is sacrosanct. The fact that it is based on statistics does not make it accurate in PG&E's case.
- PG&E should examine whether the IEEE definition is classifying too many small events as MEDs compared to the definition in D.96-09-045. Such an examination may be more difficult since PG&E has recently implemented a more inclusive interpretation of that decision such that any emergency declaration, even for a small area, can cause PG&E to omit the outage data for that area.[91]
- PG&E should undertake analysis of the frequency and response to MEDs, as recommended by IEEE. A full understanding is needed of whether the large

[91] This was not the intent of the "major" event definition agreed upon in D.96-09-045. See the summary of exclusion characteristics from that decision in footnote 72 above.

MEDs are caused by worse-than-average weather, inefficient response on the part of PG&E, or other factors.

- Any utility-caused major outage should not be classified as an MED or allowed to be excluded for purposes of outage reporting and for the STIP program.

## IV. ELECTRIC DISTRIBUTION EXPENSE

### A. POLE TEST & TREAT FOR JOINT POLES

PG&E calculates its expenses for pole test and treat (MWC GA) and offsets those costs with a credit from reimbursement from Joint Pole Owners (See PG&E-4, WP 6-7, lines 13, 21, 29, and 62). As noted on that workpaper, "historically 50% of the costs for joint poles are recovered." In other words, under current agreements with Joint Pole Owners PG&E and ratepayers are owed twice as much as PG&E is currently recovering for the pole tests and treatments that PG&E does on behalf of Joint Pole Owners to keep the poles maintained and in safe condition.

TURN requested an explanation from PG&E as to why it was not recovering 100% of the costs that are due from Joint Pole Owners. The response was: "PG&E must collect from the joint pole parties, and PG&E's collection rate depends on the parties' willingness to pay those fees." (TURN 67 Q 2).

This is an unacceptable response. Many remedies exist for PG&E to recover the amounts due, as under any contractual obligation that PG&E enters. It is intolerable that PG&E allows the situation of only 50% fee recovery to continue, and that PG&E proposes to put the consequence of its lack of full recovery on to ratepayers.

TURN recommends that ratepayers be credited with 100% of the pole test and treat fees that are due from Joint Owners. We therefore reduce the 2014 forecast for MWC GA by $1.6 million.[92] Note that this adjustment is in addition to any other adjustments to this account identified by TURN and other parties.

---

[92] Calculated as 1.09 + 0.496 million from PG&E-4, WP 6-7, lines 13 and 29.