BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms	Rulemaking 11-02-019 (Filed February 24, 2011)

PACIFIC GAS AND ELECTRIC COMPANY'S PIPELINE SAFETY ENHANCEMENT PLAN (PSEP) COMPLIANCE REPORT

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Dated: July 30, 2013

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I. INTRODUCTION

Pursuant to Ordering Paragraph 10 of Decision 12-12-030, attached is PG&E's PSEP Quarterly Compliance Report, for the reporting period April 1, 2013 through June 30, 2013.

Respectfully Submitted,

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PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)
COMPLIANCE REPORT

NO. 2013-02

REPORTING PERIOD
APRIL 1, 2013 – JUNE 30, 2013

IN COMPLIANCE WITH CPUC DECISION 12-12-030

SUBMITTED JULY 30, 2013

PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY ENHANCEMENT PLAN (PSEP)
COMPLIANCE REPORT
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Introduction

In response to the California Public Utilities Commission's (CPUC or the Commission) order in Rulemaking 11-02-019, Pacific Gas and Electric (PG&E) filed its Pipeline Safety Enhancement Plan (PSEP or Implementation Plan) on August 26, 2011 with the goal of enhancing safety and improving operations. Subsequently, the Commission issued Decision 12-12-030 on December 28, 2012. Ordering Paragraph (OP) 10 of that decision directs PG&E to file and serve quarterly compliance reports to keep the CPUC and the public informed of PG&E's progress and actual cost experience related to the Implementation Plan. Per OP 10, the PSEP Compliance Reports are to be submitted in compliance with instructions set forth in Attachment D of the decision, which is separated into 29 specific requirements.

PSEP Compliance Report No. 2013-02[1] is submitted in compliance with the instructions set forth in Attachment D and reflects the reporting period of April 1, 2013 through June 30, 2013. It is being served on the directors of the Commission's Energy Division and the Safety and Enforcement Division (formerly the Consumer Protection and Safety Division), and to the service list in the PSEP proceeding (R.11-02-019). It will also be posted on the PG&E website at http://apps.pge.com/regulation/.[2] Each subsequent report shall cover the preceding three months and will be served no later than 30 days after the conclusion of each calendar quarter.[3]

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[1] This report is labeled "No. 2013-02," to designate that it covers the reporting period ending the second quarter of 2013. Subsequent report submissions will follow this nomenclature (Note PSEP Compliance Report No. 2013-01 covers the reporting period from program inception on April 1, 2011 through the first quarter of 2013).

[2] Click on "Search" under Public Case Documents. Select "Gas Pipeline Safety OIR" from the "Case:" dropdown menu. Select filing date of 07/30/13 to narrow the search criteria. Then click Search. Report filename is "01_GasPipelineSafetyOIR_Report_PGE_20130730-PSEP Qrtly Compliance Report.docm"

[3] D.12- 12-030, Attachment D, p. D1.

Summary

PSEP is an essential part of PG&E's commitment to rigorous safety standards, improved operations and better service for its customers and the public. Since program inception in 2011 through June 30, 2013, PSEP Phase 1 costs total approximately $1.2 billion, with shareholders funding more than $700 million of that amount. Based upon current program forecasts, PG&E estimates the total cost for PSEP Phase 1 will be approximately $2.4 billion, with shareholders funding approximately $1.25 billion,[4] of that amount.

As a result of this commitment and investment through June 30, 2013, PG&E's PSEP's accomplishments include:

- Completing 485 miles of strength testing.[5]
- Replacing 59 miles of pipeline.[6]
- Upgrading 78 miles of pipeline to accept in-line inspection technology, of which 39 miles has already been inspected.
- Automating 78 valves.
- Completing the records collection and Maximum Allowable Operating Pressure (MAOP) validation of PG&E's entire transmission system.[7]
- Material improvements in PG&E's records processes and tools.

Through the end of the second quarter of 2013, PG&E's PSEP has continued to build upon an earlier start to pipeline replacement construction activities compared to 2012. Earlier completion of 2013 project engineering and continued improvements in planning activities have enabled the successful scaling of construction activities across the program with significant progress being made towards 2013 workstream targets. The following table highlights the progress of PG&E's construction activities during the second quarter of 2013 and on a year-to-date basis, in comparison to the same periods in 2012.

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[4] Includes $353 million for disallowed capital expenditures that are forecasted to exceed the CPUC authorized levels or that were specifically disallowed.

[5] Miles of strength testing includes pipeline mileage for which records of prior strength tests have been validated as meeting the traceable, verifiable and complete standard.

[6] Miles of pipeline replaced is based on pipelines in construction or tested and tied-in.

[7] In a letter dated July 8, 2013, PG&E informed the CPUC that it had completed MAOP validation as of July 1, 2013. In that letter, PG&E also requested and subsequently received approval of a 90-day extension (from July 31, 2013 to October 29, 2013) to file its Update Application as required in Ordering Paragraph 11 of Decision 12-12-030.

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF PSEP CONSTRUCTION ACTIVITY
QUARTER ENDING JUNE 30 AND YEAR-TO-DATE 2013 vs. 2012

	Q2 2013	Q2 2012	YTD Q2 2013	YTD Q2 2012
Pipeline Replacement (Miles)	8.8	3.4	18.9	3.4
Strength Testing (Miles)	44.0	47.7	66.4	64.0
In-Line Inspection (ILI) (Miles)	39	0	39	0
Pipeline Upgrades to Allow ILI (Miles)	0	0	0	0
Valve Automation (Valves)	2	4	19	24

In addition to the units completed as shown in the table above, in the current reporting period, PG&E has delivered tangible improvements to the safety of the gas transmission system, met key program milestones, and demonstrated material improvements in project success criteria, including:

- Replaced approximately 270 feet of pipeline to remediate two pipeline leaks and a rupture identified under high-pressure hydrostatic testing.
- Improved public, contractor and employee safety performance, including commencement of monthly construction contractor safety committees.
- Improved environmental compliance performance.
- Completed implementation of integrated risk management tools (High Consequence Area (HCA)[8] determination tool).
- Completed first ILI project on pipeline upgraded by PSEP.
- Completed allocation of entire 2013 PSEP construction projects to construction contractor Alliance and existing PG&E General Construction.
- Identified, commenced and—in many instances—completed the implementation of lessons learned and improvement initiatives across construction-focused workstreams and processes designed to increase the capability to meet schedule and cost commitments (see Questions 6, 7 and 17 for more detail).

As of June 30, 2013, PSEP has 44 projects in construction and is scheduled to commence another 67 in the third quarter of 2013. PG&E is focused on executing project activities effectively and efficiently throughout PG&E's service area by:

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[8] HCAs are defined as areas with 20 or more occupied dwellings, public gathering places or structures difficult to evacuate, e.g., nursing homes, hospitals, day cares, etc. (Source: 49 CFR, Subpart O, Section 192.903.)

- Engaging affected customers and local communities via phone calls, customer mailings, and open houses to increase public awareness of project operations (see Questions 24 and 25 for more detail).
- Developing, executing and monitoring project plans that put the safety of the public, contractors, and employees first (see Question 7 for further detail).
- Monitoring the quality of all critical work performed by employees and contractors (see Questions 4 and 5 for more detail).
- Updating the prioritization and scheduling of work based upon changes in pipeline information from the results of the Pipeline Records Integration Program[9] (see Question 1).

PSEP Compliance Report No. 2013-02 provides insight into PG&E's progress in completing the scope outlined in the Implementation Plan, how risks (originally identified in the filing) have influenced the actions taken on a project-by-project basis, and how PSEP program management activities have enabled and provided assurance regarding completion of work in compliance with PG&E's safety and quality standards.

This report demonstrates the progress PG&E has made in executing its Implementation Plan while recognizing that significant elements of the PSEP scope (particularly within pipeline replacement, pressure testing and valve automation) remain to be completed through 2014. Many of the risks that PG&E identified in its contingency estimate have materialized and, in spite of all mitigation efforts, have driven significant upward cost variances into both individual projects and workstreams.

Given the naturally evolving project scope and design development associated with PG&E's continuing efforts on PSEP, this report compares PG&E's incurred costs to adopted amounts at a program level to provide a meaningful and consistent comparison. PG&E will incorporate in future quarterly reports the quantification of total costs to be paid by PG&E's shareholders and ratepayers for work at the project level as identified in the Update Application[10] to be filed no later than October 29, 2013.[11] This Update Application information will enable PG&E to perform a comprehensive,

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[9] The Pipeline Records Integration Program consists of MAOP validation work and the Gas Transmission Asset Management (GTAM) project, now referred to as "Mariner Project."

[10] PG&E's Update Application will present the results of its MAOP validation and records search. Additionally, the Update Application will update its Implementation Plan's authorized revenue requirements and related budgets, consistent with this Decision 12-12-030, OP 11.

[11] Please see Footnote 7.

summary level reconciliation between the amounts adopted by the Commission in Decision 12-12-030 for anticipated work efforts and the incurred program costs.

Table 2 provides a summary of the PSEP activities and actual costs for the period of April 1, 2011 to June 30, 2013 (see Question 20 for further detail).

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF PSEP FILED VS. ACTUAL COSTS BY WORKSTREAM
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013
(IN MILLIONS OF DOLLARS)

	PG&E Filing Estimate(a)	Authorized Program Expenses(b)	Actual Costs Program Inception-to-Date (4/1/11 – 6/30/13)	Actual Costs Reporting Period (4/1/13 – 6/30/13)
Pipeline Modernization				
Pipeline Replacement	838.5		369.6	130.0
Strength Testing	452.6		434.6	57.5
ILIs/Upgrades	40.0		36.3	19.7
Subtotal	1,331.0	1,002	840.5	207.2
Valve Automation	143.6	135.7	59.4	18.7
Pipeline Records Integration	286.0	0	296.3	44.5
Interim Safety Enhancement Measures	3.2	2.1	3.2	0.8
Program Management Office (PMO) and Other(c)	34.8	28.9	40.8	8.9
Risk-Based Contingency	360.4	0		
Total	**2,159.0**	**1,168.8**	**1,240.2**	**280.1**

(a) The amounts represent PG&E's filed PSEP request, excluding Stanpac's amount of $11.3 million.

(b) Decision 12-12-030 did not authorize rate recovery for pipeline replacement and strength testing activities (based upon specific pipeline attributes), the total amounts requested for the Pipeline Records Integration Program, and risk-based program contingency. PG&E's Update Application, to be filed later this year, will update these authorized amounts (based upon the results of completing its records collection and MAOP validation project) and provide supplemental segment-level detail supporting the project-level data provided in this report.

(c) "Other" includes costs of activities pending assignment to an individual workstream or determined as not directly associated with an individual workstream.

Decision-Making Process

1. Project Planning and Prioritization of Work

Describe PG&E's project planning process including how the projects were and are being scheduled and sequenced and what measures were and are being taken to conduct the work in a cost effective manner.

Response

PSEP's prioritization and scheduling processes remain consistent with the descriptions previously provided in PSEP Compliance Report No. 2013-01 and testimony supporting PG&E's August 26, 2011 Implementation Plan.[12] Specifically, work prioritization continues to be driven from the results of applying PSEP Decision Trees to pipeline segment attribute data. Project scheduling continues to incorporate ongoing assessments of pipeline system operational safety, customer service requirements, permitting restrictions, and cost effectiveness.

During 2013, these processes have incorporated updated Decision Tree results driven from the validation of pipe segment attribute data (scope and schedule changes), verified records, permit delays, scheduling constraints that require work to be shifted to avoid a peak that exceeds available resources, and changes in integrity management assessments (schedule). Material project-level changes to scope and schedule as a result of these processes during the reporting period are provided within the "comments" column of the table responses to Questions 11 through 14. Of the 135 projects identified in PSEP Compliance Report No. 2013-01 as scheduled to commence construction in 2013, 74 were to start during the second quarter (reporting period). Of those projects, 41 commenced construction as planned within the current quarter reporting period, and 27 have been rescheduled to commence during the coming third quarter. The schedule on the remaining 6 projects, all strength test projects, remains under review.

To ensure that projects are conducted in a cost effective manner, PG&E maintains a coordinated approach to the management of project scope,

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[12] PG&E PSEP Implementation Plan (R.11- 02-019) Prepared Testimony, Chapter 3 – Gas Transmission Pipeline Modernization Program, Section A.5, and Chapter 4 – Gas Transmission Valve Automation Program, Section K.1.

schedules, resources, and risks. This approach increases the capability to communicate issues and coordinate responses; and provides a continuous focus upon individual project activities and upcoming milestones. In addition, at a workstream level, program managers are focused on implementing consistent process improvements to improve project delivery and align activities across workstreams. Details on many of these improvements are provided in response to Questions 6, 17 and 18 in this report.

Resource Procurement and Oversight

2. Resource Planning

Explain how PG&E decided whether to do the work in-house (e.g., use own employees and equipment) or contract the work out to other parties.

Response

PSEP's resource planning process remains consistent with the description previously provided in PSEP Quarterly Compliance Report 2013-01. To ensure that Implementation Plan work is completed on a timely basis, PG&E has implemented a resource management model whereby the skills and experience of existing employees are augmented by contractor resources. PG&E also uses contractor resources where it has identified the need to efficiently leverage new skills or equipment within an accelerated timeframe. Where it has identified that these resources are important to the ongoing success of the Program or its gas system operations, PG&E is in the process of acquiring equipment and training existing or hiring additional employees.

Central to the adoption of this strategy was the scope and timeline inherent in the CPUC Decision 11-06-017 to commence Implementation Plan activities and the significant scope of the work identified in PG&E's Implementation Plan. PG&E's August 2011 PSEP filing itself leveraged significant support from contractor resources (e.g., engineering and construction estimators) and fully anticipated that a significant level of contractor support would be required to execute the Program. PG&E indicated in its testimony that much of the work identified in the Implementation Plan was considered to be in addition to current activities and in response to the implementation of new industry standards. As such, the use of contractor resources was an intrinsic element in how PG&E formulated and proposed to execute the Implementation Plan.

Finally, in completing work using contractors, PG&E is aware that the contractor's quality of performance is central to the success of the Program. PG&E ensures that contractors provide appropriately trained staff and deliver work in compliance with PG&E standards and work procedures, while taking all actions consistent with maintaining the safety of the public and employees.

3. Contractor Selection Process

For work contracted out to other parties, what criteria did PG&E use to select the contractors and did PG&E use a competitive bidding process to select the contractor(s)? If not, explain why.

Response

No material changes in PG&E's contractor selection and competitive bidding processes, as previously outlined in the PSEP Compliance Report No. 2013-01, have been made during the current reporting period. PSEP has continued the implementation of an Alliance Construction contractor delivery model, completing the preliminary assignment of all 2013 PSEP construction projects to PG&E General Construction and Alliance Construction contractors. The primary objectives of the alliance strategy remain the establishment of best-in-class safety performance, a robust construction delivery model, and the maintenance of a qualified/skilled workforce to perform work planned in 2013 and the future.

The alliance model includes the following key components:

Resources and Planning

- Consistent "A" team availability and scalable crew composition.
- Commitment to provide early constructability feedback via joint planning and co-location.
- Bundling of work across PSEP workstreams and within four regional areas that span PG&E's entire service area to reduce "peaks and valleys."
- Collaboration on industry best practices and lessons learned.

Performance Measurement

- Increased transparency and alignment across construction cost estimation models using negotiated standardized "open book" labor and equipment rates and consistent overhead (general and administrative expenses).
- Shared project risk/incentive model using negotiated "target pricing" model which shares under and over runs on a 50:50 basis.
- Project completion cost true-up and lessons learned—costs being fully auditable where appropriate.
- Five year agreement with cancellation off ramps, including option to bid any portion of work to maintain pricing/cost discipline.
- Monthly program scorecarding and quality leadership reviews.

As of the end of June 2013, PG&E has agreed to target pricing on approximately 58 percent of 2013 construction projects, 14 of which have completed construction. The remaining 2013 construction projects are planned to complete target pricing negotiations during the next quarter. All other 2013 construction projects, outside of the alliance contracting process, are being completed with existing suppliers using competitive bidding or using existing Master Service Agreements (MSA) that were previously subject to competitive bidding.

4. Quality Assurance – Outside Contractors

How does PG&E monitor the quality of work performed by outside contractors? Has PG&E found any instances where a contractor failed to do the work properly? If so, what actions did PG&E take in response?

Response

PG&E's contracts require contractors to consistently follow the same PG&E standards followed by internal resources, and holds contractors accountable for instances where such standards have not been followed.

The PSEP PMO structure and procedures incorporate PG&E procedures that monitor contractor compliance with these contractual quality commitments and check the quality of work performed from two perspectives.

The first involves oversight within each line of business to ensure individual process quality and ensure compliance with PG&E standards. For example, construction inspection procedures follow PG&E's inspection standards and involve the checking of field construction activities using a Quality Control (QC) manual to ensure proper procedures are followed and the appropriate forms are completed. Given the scope of PSEP construction activities, much of this work may itself be performed by third-party contractors. Partially for this reason—and more importantly—to provide additional Quality Assurance (QA) that PG&E procedures are being followed and that work is consistently being performed to PG&E standards. Additional quality procedures are undertaken by staff not linked to the performance of the original work.

This second area of responsibility is conducted on a randomized basis to support analysis and involves assessments that document the performance of reviews that check adherence to PG&E standards and the completion of required work process forms. These random assessment activities on PSEP construction projects include, but are not limited to, areas such as trenching, backfill and compaction, water discharge plan compliance, test plan compliance, inspector qualification, welder qualification and compliance with weld procedures, weld repair rates, pipeline surface prep and field-applied coating application.

The results of these quality monitoring processes are documented and used to measure the level of quality and provide feedback to PG&E and our contractors on issues discovered. In addition to communicating these issues back to the contractor, PG&E has implemented a formal corrective action program.

This program is used to address internal process, material and systemic issues that are discovered.

PG&E has found instances where the contractor did not perform quality work in accordance with the written procedures. In such situations, and as appropriate, PG&E takes specific actions to maintain the integrity of its gas transmission system and ensure such instances do not reoccur. Examples of such quality issues identified during the reporting period include:

- As part of quality assurance activities performed by specialist personnel from PG&E's Applied Technologies Services organization on Non-Destructive Examination (NDE) processes, it was determined that inadequate weld inspection and documentation had been performed by a specific inspection contractor's personnel supporting a pipe replacement project on Line-114. PG&E immediately commenced a review of all radiographic inspection activities completed by the contractor on the affected project and is in the process of re-inspecting all affected weld sites prior to completing the project. PG&E has also undertaken and completed an "extent of condition" analysis including all weld inspection work previously performed by these contract personnel. PG&E has revoked its contract with the NDE contractor and is pursuing re-imbursement for the cost impacts associated with all remediation work.
- A PG&E QC Specialist, as part of Welding Assessment on a pipe replacement project on Line-167 identified that the Daily Field Weld Summary Report was missing the Welder IDs. A Corrective Action Form was completed and the documentation error was corrected the same day, closing the corrective action.
- As part of field quality control procedures, PG&E identified during a strength test (T-223A) that contractor personnel had placed a weld bead on the threaded nipple of a test head flange. PG&E validated that this weld activity had not been approved and ensured that the contractor replaced the flange. QC and QA procedures related to MAOP validation remain consistent with details provided in PSEP Compliance Report No. 2013-01.

5. Quality Assurance – Internal Resources

What quality assurance procedures does PG&E have in place to determine whether the project work is being done correctly by its own employees? Has PG&E found any instances where the work was not done properly? If so, what actions did PG&E take in response?

Response

The PSEP PMO structure and procedures include specific areas of responsibility for QA. While each line of business maintains oversight to ensure individual process quality and ensure compliance with PG&E standards, the PSEP PMO since inception has established procedures to independently monitor work performed by employees to ensure its adherence to PG&E standards and thereby assure quality. These assurance procedures involve random assessments that review work activities and documentation for completeness and adherence to the PG&E standard. These random assessment activities on PSEP construction projects include, but are not limited to, areas such as trenching, backfill and compaction, test plan compliance, water discharge plan compliance, inspector qualification, welder qualification and compliance with weld procedures, weld repair rates, pipeline surface prep and field applied coating application. The results of these quality monitoring processes are documented and used to measure the level of quality and provide feedback to the line of business on issues discovered. In addition to communicating these issues back to the line of business, PG&E has implemented a formal corrective action program. This program is used to address internal process, material and systemic issues that are discovered.

PG&E has found instances where our employees did not perform quality work. In such situations, and as appropriate, PG&E takes specific actions to maintain the integrity of its gas transmission system and ensure such instances do not reoccur. An example of such quality issues identified during the period includes:

- QC inspection of welding documentation (Daily Field Weld Summary Reports (DFWSR)) identified typographical errors. A "Corrective Action Form" was completed and the corrective action was closed after all errors were validated as corrected upon subsequent follow-up review.

When PG&E employees' work product contains errors, it is returned to the employee for correction when appropriate. The rejected work product contains a similar type of technical corrective action request that a contractor would receive.

In the second quarter of 2013, the PSEP PMO has completed the integration of PSEP QA within the Gas Operations Quality and Improvement organization which spans all Gas Operations construction activities, including Gas Transmission, and utilizes consistent QA processes and qualified resources.

6. Project Management Office Overview

Describe the role of the Program Management Office (PMO) (see p. 7-10 of Prepared Testimony) in containing project costs. Provide specific examples where the PMO's recommendations led to cost savings.

Response

The role of the PMO, as described in the prepared testimony referenced in the question above, remains unchanged and its objectives can be summarized as follows:

- To help manage the overall Program execution and to coordinate the activities of inter-related projects or work streams.
- To provide oversight and provide observations and recommendations for process improvements and enhanced performance.
- To provide assurance that Program control tools and procedures are operating in the way they are intended to achieve Program objectives.

The operation of each of the groups within the PMO support these objectives and in doing so contribute to the cost effective execution of the Implementation Plan. In 2013, the PMO has worked with each workstream to identify and prioritize a series of improvement initiatives that are designed to influence a broad range of program performance factors, including cost efficiency. While it is not possible to accurately segregate and quantify individual cost savings impacts, initiatives that are anticipated to provide the most significant impact in helping to achieve 2013 program budget and operational targets include:

- Broader application of project-level functional budgeting: includes additional project-specific tracking of budget to actual hours and costs for primary functional cost categories (e.g., Construction Management and Inspection).
- Increasing consistency of construction resources: includes alliance construction contractor commitments to provide consistent and sustained access to "A-team" resources to efficiently execute bundled PSEP work across an assigned region.
- Alliance construction contractor partner pricing: consistent availability of competitive equipment and labor rates within a negotiated target pricing mechanism with appropriate cost efficiency incentives.
- Development and implementation of an information technology system to track and approve change orders and documents to reduce stand-by time for

contractors waiting for approval to proceed with a change and clearer visibility into the magnitude of change orders under review.

- Consolidation of consistent project activities into program-wide service agreements that leverage consistent best practices and improve unit costs: includes NDE (X-ray) services and site remediation.
- Improved onboard training for Construction Management personnel, including construction managers and inspectors.

A broader list of lessons learned is being implemented and tracked within each workstream and is provided in response to Question 17.

7. Project Management Office Costs and Benefits

Provide the costs incurred by the PMO year-to-date and describe the specific work they did for the benefit of PG&E customers.

Response

The PSEP PMO incurred approximately $5.8 million during the period January 1, 2013 through June 30, 2013. Consistent with PG&E's commitment to customers to provide safe, reliable, and affordable gas service, the PSEP PMO is responsible for the successful delivery of all projects within PG&E's Implementation Plan.

During 2013, the PMO, in partnership with project teams and cross-functional leads including PG&E's Customer Care and Corporate Communications organizations, is focused on many areas that directly benefit customers including:

- <u>Improving Construction Site Safety</u>: Implemented a series of safety-focused activities designed to improve construction site safety for employees, customers, and local communities, including leadership site visits, "good catch" reporting, after-hours site security audits and job hazard mitigation analyses. In addition, the program has added new metrics to track targeted 10 percent performance improvements for the incidence of construction-related public safety incidents and at-fault "dig-ins." Through June 30, 2013 on a year-to-date basis, these metrics were 91 percent and 35 percent, respectively, below prior year rates and remain on track to meet or exceed 2013 targets. PSEP's 2013 recordable incident rate of 0.82 as of June 30, 2013, also reflects a significant improvement compared to both industry average and prior year performance for the same period.
- <u>Improving Environmental Compliance</u>: Inspection findings and feedback to PG&E and contractor construction resources have focused on addressing compliance performance related to approved soil off-haul procedures, storm water management plans, dust control readiness and implementation, and fire prevention and response readiness. Through June 30, 2013, PSEP remains significantly ahead of plan to meet or exceed a 10 percent reduction in its 2012 environmental compliance incidence rate.
- <u>Maintaining Consistency of Pre-Construction Customer Communications</u>: During 2013, PG&E continues to deliver extensive PSEP construction-related customer communications, including pre-venting notification, open houses

and customer communication materials, across Implementation Plan construction activities. PG&E is working to integrate PSEP-related activities and safety-related messages within broader customer-focused communications such as divisional local service bulletins.

- Improved Construction Project Bundling: PG&E consistently seeks to align PSEP construction schedules and bundle work across workstreams, including non-PSEP projects. Bundling enables potential reductions in the required system clearances, clearance resources, and the duration and impact of construction-related service and traffic disruptions.
- Customer Outage Management: PG&E is continuing significant increases to its compressed and liquefied natural gas equipment (CNG/LNG) fleet. Project planning improvements are focused on better identifying potential customer demand requirements and integrating this information into project schedules. This will improve the availability of CNG/LNG equipment for projects to meet customer demand, minimize planned customer outages and reduce the risk of unplanned customer outages.

The PMO's role includes many activities that also indirectly impact customers including, but not limited to, the implementation and management of consistent program controls and governance, quality control, reporting and improvement initiatives designed to improve project success and increase cost efficiencies.

Budgeting and Spending

8. Factors Impacting Cost Effectiveness

Describe any factors, either internal or external, that may have prevented or affected PG&E from conducting the work in a more cost-effective manner. Quantify the cost impact of such factors.

Response

PG&E has consistently sought to identify foreseeable risk factors in executing the planned PSEP work scope and address additional challenges that, due to nature of the work itself, cannot yet be identified but can be reasonably expected to be encountered through the normal course of executing a program of PSEP's scope and depth. Many of these uncertainties and risks have materialized and, in spite of all mitigation efforts, have driven significant upward cost variances into both individual projects and workstreams. These factors have included, but are not limited to, the following:

- <u>Project Scope and Committed Phase 1 Timeline</u>: Changes in pipeline data upon completion of data validation and prioritization of individual pipeline segments to maintain system integrity and public safety (shortened project lengths, increased project counts and reduced development schedules).
- <u>Pipeline Routing Restrictions</u>: Increased complexity of pipeline routing due to the limitations upon the use of urban franchise areas due to existing utilities and infrastructure.
- <u>Geographical Conditions</u>: High water table, trench dewatering costs, excessive permitting conditions, site specific contamination, and excessive waste disposal fees (increased construction duration and costs).
- <u>Permitting and Land Rights</u>: Delays and uncertainty in receiving permits from state and local authorities while acquiring additional land rights from customers (compacted construction schedules). For example, projects being forced to adopt costly "in-road" construction within franchise rather than being able to pursue cheaper verge construction that is subject to extended permitting timelines.
- <u>Unidentified Pipeline Field Conditions</u>: Additional construction activities including pipeline cleaning particularly to meet unique waste water disposal requirements, the removal of known and unknown pipeline anomalies,

the repair and replacement of pipe, valves and fittings due to condition, and construction obstructions and re-engineering due to previously unidentified non-PG&E structures or utilities (increased construction duration and costs).

- Gas System and Customer Service Constraints: Limited availability of gas system clearances due to seasonal customer demand and system operations, safety-related pressure reductions, CNG/LNG resource requirements, and the availability of PG&E crews to complete tie-ins, particularly during peak summer construction periods and towards the end of the calendar year.

The specific impact of these risks upon individual projects completed in 2013 is also provided in our response to Question 19.

In aggregate and on an inception-to-date basis, the above items have resulted in strength testing costs being approximately 100 percent higher than original filing estimates included in the August 2011 Implementation Plan. The 2013 strength testing budget targets a unit cost of approximately $0.97 million per mile which itself reflects a reduction of 5 percent, or approximately $8.9 million against actual 2012 unit costs.

The pipeline replacement project portfolio has similarly been affected by the above factors, with forecast unit costs representing an approximately 24 percent increase over the original filing estimate for 2013, or 18 percent on a program inception-to-date basis. It should be noted that on an individual project basis, significantly higher unit replacement cost variances are being identified, which on a portfolio basis are subject to offset by reduced project costs associated with projects being addressed using pipeline retirements. Unit costs for pipeline replacement are forecast to continue to increase in 2014 as the program addresses some of the most challenging projects from an engineering and permitting perspective. Valve automation continues to monitor 2013 costs associated with projects previously scheduled in 2012 that were materially impacted due to delays in receiving environmental and encroachment permits on certain San Francisco Peninsula projects. Finally, continued increases to engineering and construction work associated within ILI upgrade/retrofit projects, continue to drive program costs significantly above original filing estimates.

9. Procurement Policy and Practices

Describe PG&E's procurement policy and practices for pipe and other materials used for projects. Was a competitive bidding process used? If not, explain why. Describe what factors PG&E considers in procuring material ranked by importance. Identify the manufacturer(s) or suppliers of the pipe used for the replacement projects and for any material that cost more than $100,000 per item.

Response

The majority of all material is purchased from existing suppliers through MSAs, the terms and conditions of which (including unit pricing) are the result of a competitive bidding process.

Material supplier selection and competitive bidding processes and factors previously described in PSEP Compliance Report No. 2013-01 were unchanged during the current reporting period.

Manufacturers or suppliers of the pipe used for PSEP replacement projects are:

- Berg Pipe;
- Durabond Industries; and
- California Steel Industries.

No materials procured during the current reporting period cost more than $100,000 per item.

10. Pipeline Disposition Procedures and Costs

What was the disposition (e.g., sold) of replaced pipe and other material? Identify all the amounts earned for the disposition of the material, costs incurred to transport or dispose of the material and regulatory treatment of the incurred costs and revenues.

Response

The disposition of transmission pipeline and other material replaced as part of the PSEP program—stored, hazardous waste, retired-in place or salvage—and related cost allocations as described in PSEP Compliance Report No. 2013-01 remain unchanged during the reporting period. For the reporting period and on a year-to-date basis PG&E has recovered approximately $37,000 and $54,000, respectively, as a result of salvage activities.

Project Status Summaries

11. Projects Completed During Reporting Period

Provide a complete description or a specific reference to proceeding workpapers, of projects completed during this reporting period and those completed Year-to-Date, include the start and finish dates. On a project-by-project basis, provide the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred completing of the project. Identify the amount that a project was over or under-budget. Indicate whether the work was done in-house or by outside contractor(s). Identify the outside contractor(s). Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project. Identify costs that shareholders will absorb.

Response

Table 11-1 of the Appendix provides details on 41 individual projects across four PSEP construction workstreams that were completed by PG&E during the reporting period.[13] With respect to these projects, Table 11-1 includes specific reference to proceeding workpapers, including the construction start and finish dates.[14] In addition it provides, on a project-by-project basis, the amount budgeted for the project and an itemized list of the costs, including labor and material, incurred in completing the project; the amount that a project was over or under-budget; and whether the work was completed in-house or by outside contractor(s), including the identification of the outside contractor(s). All work detailed in the table was undertaken in compliance with Decision 11-06-017; each project including pipeline segments for which a prior strength test has previously not been performed and/or for which traceable, verifiable and complete records of such a test do not exist. As PG&E progressed from the preliminary work scope and associated estimates and work plans included in its Implementation Plan filing, it developed more specific work plans and estimates. These refined

[13] For the purposes of this report, the completion of a project is the date the pipeline segments and valves are returned to operations.

[14] For projects completed during the reporting period, construction finish dates may reflect the anticipated finish date of construction activities.

estimates, or “Job Estimates,” are used in this report for Questions 11 through13 and 15 to represent the budgeted amount by project for a more meaningful comparison. Given the continually evolving project scope associated with PSEP, PG&E will have to reconcile its total incurred costs for the work scope contemplated in the Implementation Plan filing to the amounts adopted by the Commission upon completion of the PSEP Phase 1 work scope. As part of this reconciliation, PG&E will be able to provide descriptions of how work was performed in compliance with Decision 11-06-017, the associated Decision Tree outcome identifier, and costs in excess of the authorized amount for expense and capital expenditures at the project-level, but that information is not yet available for this report. Table 11-2 provides a reference for the specific data points requested in Question 11 to their corresponding columns in Table 11-1 of the Appendix. Additional data points are included for context in navigating the tables.

TABLE 11-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 11-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing Project Status and Reporting System (PSRS)	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition.
Order Number	Financial system of record reference number to track specific costs, e.g., on individual projects.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing. Includes project reference IDs that start with a letter that reflects the construction activity or workstream (i.e., R – pipe replacement, T – strength testing, V – valve automation, and I – in-line inspection).
City	Location of project.
Construction Contractor	Contractor who performed the work ("GC" refers to PG&E in-house general construction).
Mobilization Date	Project start date.
Tie-In Date	Project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Total Cost	Itemized costs per project completed.
Labor Cost	
Materials Cost	
Contracts Cost	
Other Cost(a)	
Variance to Budget	Variance between Total Cost and Job Estimate (see Question 19).
Non-PSEP Costs	Project costs not recoverable within PSEP.

(a) Other costs include costs not included in Labor, Materials, or Contracts such as overhead.

TABLE 11-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 11-1 COLUMN REFERENCE
(CONTINUED)

Column Name	Description
PSEP Disallowed Cost	Project costs disallowed based on CPUC Decision, i.e., post-1955 pipe work (does not include any estimation of amounts in excess of individual workstream authorized expenses and capital expenditures).
> 10% Over Budget	Projects greater than 10 percent over Job Estimate.
Comments	High-level descriptions of changes to the project agenda including project additions, accelerations, delays, and cancellations.

12. Projects Started, Pending Completion

Provide a complete description, or a specific reference to proceeding workpapers, of projects that have begun but are currently unfinished, include the start and anticipated completion dates. On a project-by-project basis, provide the amount budgeted for each project. Explain how the work is being done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, provide the Decision Tree outcome identifier associated with each project.

Response

Table 12-1 of the Appendix provides details on 44 individual projects across five construction workstreams[15] on which construction has been commenced by PG&E and has not yet been returned to operations (tied-in) as of June 30, 2013. Table 12-1 includes specific reference to proceeding workpapers, of projects that have started construction but are not yet completed[16] as of the end of the reporting period, including the construction start and anticipated finish dates. In addition, it provides, on a project-by-project basis, the amount budgeted for the project.

All work detailed in the table was undertaken in compliance with Decision 11-06-017; each project included pipeline segments for which a prior strength test has previously not been performed and/or for which traceable, verifiable and complete records of such a test do not exist. PG&E will provide the specific engineering decision tree results supporting the actions being taken within the PSEP program upon completion of its MAOP records validation process and as part of its subsequent Update Application. Table 12-2 provides a reference for the specific data points requested in Question 12 to their corresponding column in Table 12-1 of the Appendix. Additional data points are included for context in navigating the tables.

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15 Includes: pipeline replacement, strength testing, ILI, pipeline ILI upgrades, and valve automation.

16 For the purposes of this report the completion of a project is the date the pipeline segments are returned to operations.

TABLE 12-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 12-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Mobilization Date	Project start date.
Tie-In Date	Anticipated project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Comments	High-level descriptions of changes to the project agenda including project additions, accelerations, delays, and cancellations.

13. Projects Planned, But Yet to Start

Provide a complete description, or a specific reference to proceeding workpapers, of projects that were forecasted for Phase 1 that have yet to start, include the anticipated start and anticipated completion dates. Rank the priority of these projects and explain the ranking. On a project-by-project basis, provide the amount budgeted for the project. Explain how the work was done in compliance with D.11-06-017 and PG&E's Decision Tree and, if so, identify the Decision Tree outcome identifier associated with each project.

Response

Table 13-1 of the Appendix provides detail on 115 individual projects across five construction workstreams on which pre-construction activities have commenced but construction resources have not yet mobilized as of June 30, 2013.

Table 13-1 provides specific reference to proceeding workpapers, of projects that have yet to commence construction as of the end of the reporting period.[17] For each project, PG&E has supplied the current anticipated construction start and finish dates, which reflect the updated output of the prioritization and schedule procedures or ranking noted in response to Question 1. In addition, the table provides, on a project-by-project basis, the amount budgeted for the project. All work detailed in the table was undertaken in compliance with Decision 11-06-017; each project including pipeline segments for which a prior strength test has previously not been performed and/or for which traceable, verifiable and complete records of such a test do not exist. PG&E will provide the specific engineering decision tree results supporting the actions being taken within the PSEP program upon completion of its MAOP records validation process and as part of its subsequent Update Application. Table 13-2 provides a reference for the specific data points requested in Question 13 to their corresponding column in Table 13-1 of the Appendix. Additional data points are included for context in navigating the tables.

[17] Includes projects that have commenced pre-construction activities, but not yet mobilized.

TABLE 13-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 13-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Mobilization Date	Anticipated project start date.
Tie-In Date	Anticipated project finish date.
Job Estimate Amount	Amount budgeted for project after completing project engineering, routing, permitting and construction bids.
Comments	High-level descriptions of changes to the project agenda including project additions, accelerations, delays, and cancellations.

14. Additional Projects Not in Original Workpapers

Describe, in detail, projects that PG&E has completed, are work-in-progress, or have yet to start that were not included in the workpapers submitted in R.11-02-019. Explain why these projects have been included in Phase 1 and whether these projects have lowered the priority of other projects identified in proceeding workpapers and, if so, why. Explain how this work complies with D.11-06-017 and PG&E's Decision Tree and provide the Decision Tree outcome identifier associated with each project.

Response

In the tables referenced in PG&E's prior responses to Questions 11 through 13, PG&E has identified 6 projects that were not included in the workpapers submitted in Rulemaking 11-02-019. In each case, an explanation of why these projects have been included in Phase 1 is provided in the column titled "Comments". To date, PG&E has not lowered the priority of other projects that were planned in the August 2011 filing. PG&E will provide the specific engineering decision tree results supporting the actions being taken within the PSEP program upon completion of its MAOP records validation process and as part of its subsequent Update Application.

15. Project Costs > 10% Above Estimate

For completed projects that are 10% or more over estimated costs, provide a detailed explanation why the overrun occurred.

Response

As PG&E progressed from the preliminary work scope and associated estimates and work plans included in its Implementation Plan filing, it developed more specific work plans and estimates. These refined estimates, or "Job Estimates," are used in this report to represent the budgeted amount by project for a more meaningful comparison. Table 11-1 of the Appendix referenced in the response to Question 11 includes nine[18] projects that have cost variances equal to or greater than 10 percent of the budgeted amount, on a project-by-project basis. Identification of the cost and schedule impacts that have driven these cost variances are included within the project-by-project risk analysis on Table 19-1 provided in response to Question 19.

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[18] Includes pipe replacement project R-029, which was split in the current period to complete closeout of scope previously tied-in in 2012. Cost and schedule impact drivers associated with realized 2012 risks on this portion of the project were previously reported in PSEP Compliance Report 2013-01 and are not included in this report.

16. Pipeline Piggability Status

Provide a list and map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP. Provide the total mileage of transmission pipelines, the total mileage of pipelines that are currently piggable and percentage of the total that is piggable.

Response

As shown in Table 16-1 below, 79.13 miles of transmission pipeline (39.95 miles from transmission pipeline 300A, and 39.78 miles from transmission pipeline 300B) were made piggable under PSEP from program inception through June 30, 2013. There have been no additional lines completed from Q1 2013 to the end of Q2 2013, although work is currently in progress.

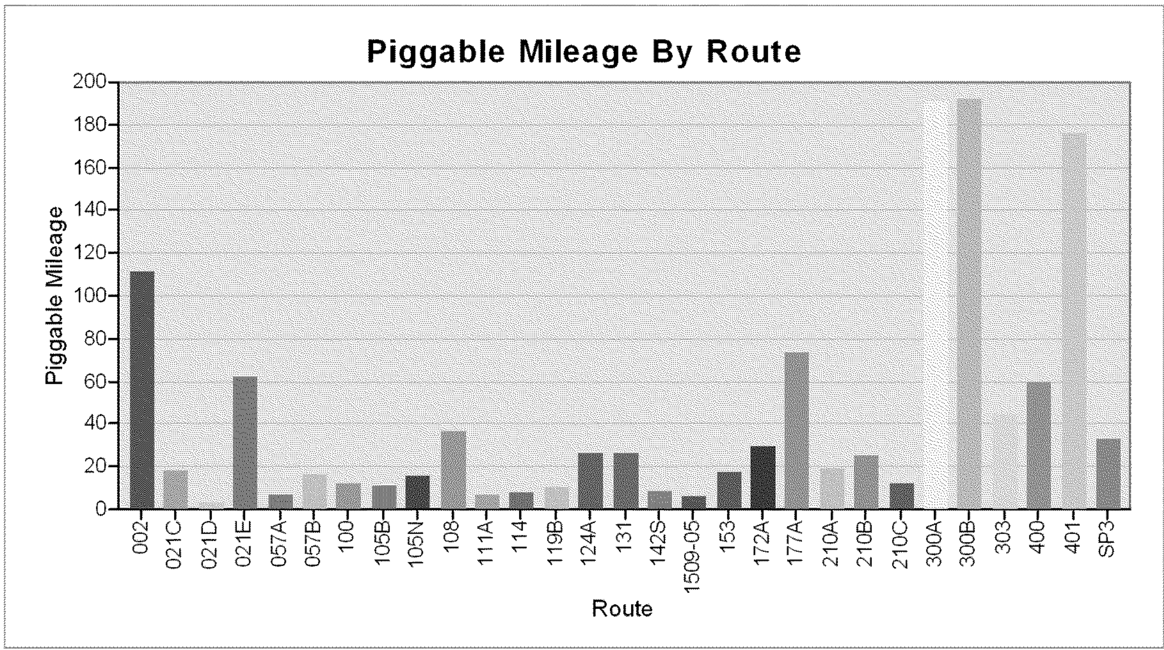
TABLE 16-1
PACIFIC GAS AND ELECTRIC COMPANY
SEGMENTS MADE PIGGABLE UNDER PSEP

Route ID	Launch Mile Point	Receiver Mile Point	Piggable Distance(a)
300A	354.19	393.53	39.35
300B	354.09	393.61	39.78

(a) Piggable Distance is measured in PG&E's Geographic Information System (GIS) and does not necessarily equal the difference between launch mile point and receiver mile point.

Figure 16-1, shows PG&E's total piggable mileage by transmission pipeline. In total, there are 1,270.52 miles of piggable transmission pipeline (see Table 16-2), which amounts to 18.87 percent of PG&E's 6,734.16 total transmission pipeline miles (as of June 30, 2013). Figure 16-2 provides a map of pipelines that are currently piggable, highlighting pipe that was made piggable as a result of projects conducted under the PSEP.

FIGURE 16-1
PACIFIC GAS AND ELECTRIC COMPANY
PIGGABLE MILEAGE BY TRANSMISSION LINE



SB_GT&S_0152269

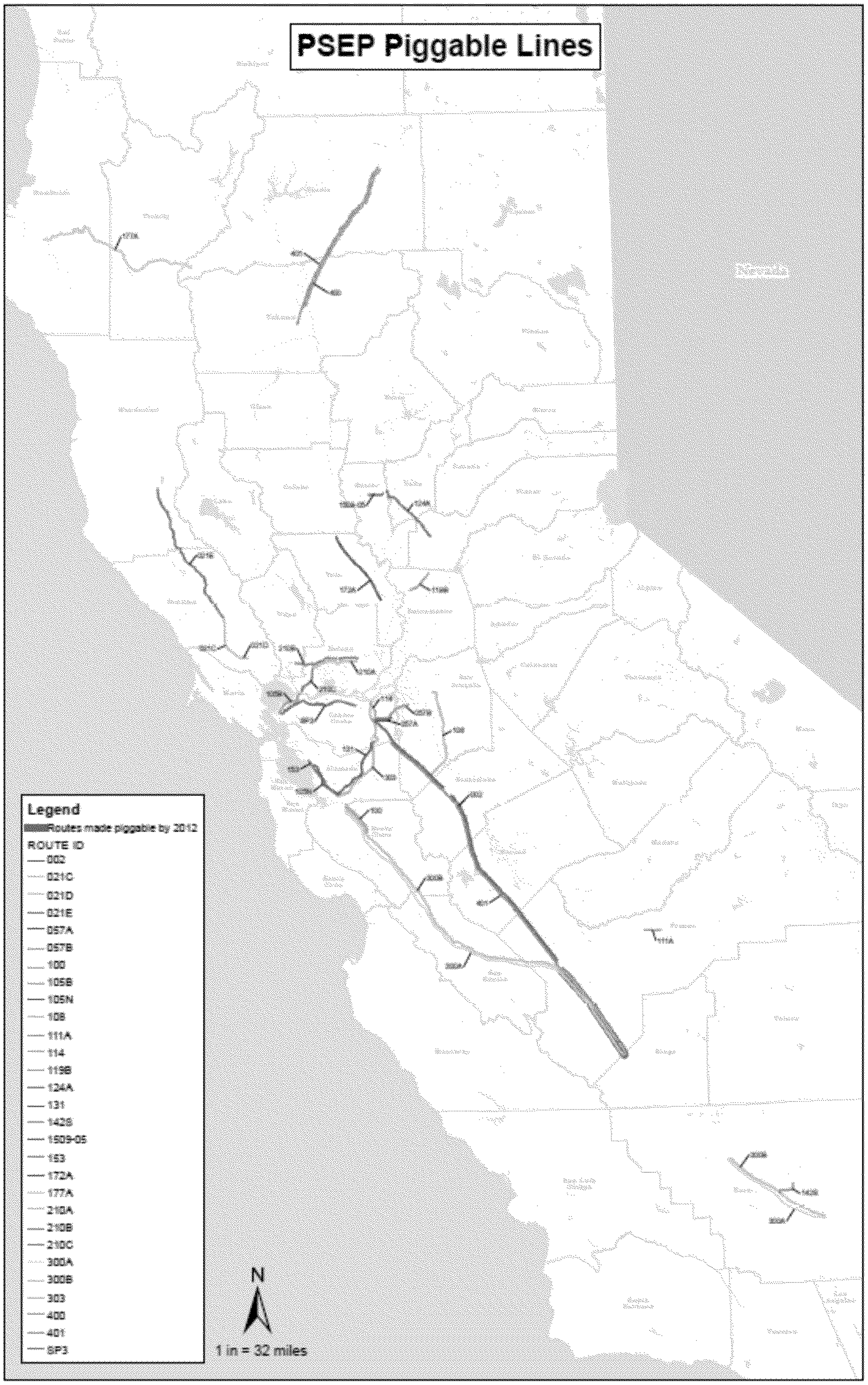
TABLE 16-2
PACIFIC GAS AND ELECTRIC COMPANY
PIGGABLE TRANSMISSION PIPELINE SEGMENTS

	Piggable Pipeline Segments		
Route	Launch Mile Point	Receiver Mile Point	Piggable Distance*
002	43.45	118.02	75.28
002	122.06	158.00	36.39
021C	35.05	53.12	18.67
021D	18.65	21.88	3.22
021E	53.12	64.36	11.39
021E	64.54	93.67	30.77
021E	93.67	114.89	20.20
057A	9.18	16.68	7.41
057B	0.00	16.68	16.62
100	138.43	150.13	11.96
105B	0.00	11.81	11.84
105N	7.75	23.00	16.27
108	0.00	37.15	37.05
111A	20.32	27.58	7.26
114	9.03	16.59	8.02
119B	0.00	10.16	10.60
124A	0.00	26.03	26.42
131	24.88	50.57	26.19
142S	0.00	9.01	9.06
1509-05	0.00	6.49	6.45
153	0.00	17.65	17.86
172A	40.07	69.81	29.78
177A	88.80	163.04	74.48
210A	1.38	19.47	18.98
210B	1.37	25.98	25.65
210C	19.46	32.11	12.75
300A	256.21	299.00	43.39
300A	393.53	450.83	57.29
300A	450.83	502.24	52.01
300A**	354.19	393.53	39.35
300B	256.64	299.00	43.23
300B	393.76	450.79	57.18
300B	450.79	502.64	52.45
300B**	354.09	393.61	39.78
303	0.00	42.83	44.72
400	82.33	142.61	60.28
401	82.34	149.19	67.01
401	317.95	427.98	110.06
SP3	167.31	198.49	33.19
Total			**1,270.52**

* Piggable Distance is measured in GIS and does not necessarily equal the difference between launch mile point and receiver mile point.

** PSEP segment.

FIGURE 16-2
PACIFIC GAS AND ELECTRIC COMPANY
MAP OF PIGGABLE PIPELINES



17. Lessons Learned in Phase 1 Work

Describe any lessons learned from undertaking the Phase 1 work that has led to cost efficiencies and quantify any cost savings.

Response

As previously described in detail within PSEP Compliance Report No. 2013-01, during 2012 PSEP developed a track record of identifying lessons learned and implementing process improvements to improve project delivery and cost efficiency.

In 2013, PG&E has extended this lessons learned process to include all other construction workstreams (i.e., Pipeline Replacement, Valve Automation and ILI Upgrades/ILI Inspections). Response to Question 6 in this report highlighted the role PMO plays in coordinating the program wide implementation of key initiatives lessons. In addition, each workstream tracks a series of specific 2013 process improvements at a detailed level, which includes:

- Improving chemical cleaning handling by reducing the amount of waste by using a lower pH cleaning solution and using train cars, rather than trucks, to ship waste to an approved facility rather than trucking.
- Utilizing PG&E-owned baker tanks and test heads to reduce lease and fabrication costs.
- Reducing the need for excess overtime and stand-by time by training and utilizing on-site contractors to perform "tie-in" work typically performed by PG&E resources.
- Improving the dispatching of inspectors to reduce unnecessary inspector hours on-site.
- Reducing in labor overtime costs by restricting project schedule and activities to support 6 × 10 workdays.
- Improving the selection criteria used to determine pipe assessment process (H form versus A form when pipe characteristics are unknown or of low quality based upon pipeline features list or when a leak or other anomaly is found).
- Reducing reliance on Division and Local Transmission and Restoration resources by increasing the use of Alliance contractor resources to complete tie-in welds, "cut and cap" and clearance activities—includes additional PG&E mobile resources to supervise these clearance activities.

- Implementing a series of long-tests in-series to reduce mobilization costs and improve crew utilization (T-206-13 through T-211-13 on Line 187).
- Projecting when a pipeline has low mercury levels that allow us to directly weld on a test head rather than weld on a launcher and receiver, and conduct cleaning runs.
- Reusing of test water for site restoration.
- Implementing a higher cleaning target threshold for cleaning runs to account for demonstrated subsequent cleaning impact of rinse runs.
- Adopting improved contractor Request for Information (RFI) response times.
- Realigning safety inspection responsibilities across existing Construction Management resources.
- Defining and implanting a specific constructability review step with alliance contractors, including sign-off on identified temporary construction easements.
- Increasing the timeliness and quality of potholing and surveying activities, including use of ferrous and non-ferrous detection tools such as ground-penetrating radar.

18. Potential Enhancements to Phase 2 Planning and Budgeting

How will the work PG&E conducts in Phase 1 influence how PG&E will plan and estimate the costs of its proposed projects for Phase 2?

Response

Consistent with our response in Report 2013-01, the work PG&E conducts in Phase 1 will have a direct influence on how PG&E will plan and estimate the costs of its proposed future projects, including:

Employee and Public Safety: In delivering on its commitments in PSEP Phase 1, PG&E has focused upon maintaining employee and public safety as the primary consideration. As a result, PG&E has taken specific actions to engage employees, contractors and customers on the underlying reason for undertaking the work in Phase 1. This has resulted in increased levels of accountability for customer outreach, safety performance and quality. PG&E anticipates that in planning future work it will continue to place employee and public safety as the primary consideration in all that PG&E does.

Risk Management: Having completed the unprecedented level of construction activities in Phase 1, PG&E will have a clearer understanding of the risk profile of projects and the key mitigation activities that are essential to project success (e.g., in 2012, PG&E successfully developed and continues to utilize specific pipeline cleaning and water handling procedures that dramatically improved PG&E's ability to execute effective and efficient strength tests). PG&E identified these and other significant potential risks in its original contingency request and will now be better able to demonstrate the potential impact such factors will have on planned projects in the future.

Cost Drivers and Resource Management: Having successfully scaled to meet the unprecedented construction commitments in Phase 1, PG&E will have a greater understanding of the attainable efficiency levels through future years of the Implementation Plan (e.g., in 2013, PG&E is continuing to work to address resource constraints associated with peak summer construction volumes). PG&E anticipates that the more flexible resource support models and process refinements that are being identified and implemented to improve resource capabilities in Phase 1 will provide greater certainty surrounding cost forecasts in future phases. In addition, the large number of projects completed in Phase 1 will significantly improve the data set from which to validate the reasonableness of future cost models updates and outputs.

Scope Definition: Having completed MAOP records validation of PG&E's entire gas transmission pipeline system during Phase 1, PG&E now has access to improved pipeline feature information. Validation of future work, including proposed project lengths and decision-tree results, will be able to be completed much earlier than was possible in Phase 1. This creates the potential to possibly avoid the related schedule and cost uncertainties identified and realized in Phase 1.

Scheduling and Prioritization: Incorporating PSEP decision tree analysis within a broader risk-based integrity management prioritization approach that enables the appropriate scheduling and bundling of activities along a longer-term time horizon which, subject to appropriate work volume and unit costs commitments, will better enable PG&E to better anticipate and mitigate the potential impact of the risks identified during Phase 1.

As PG&E progressed from the preliminary work scope and associated estimates and work plans included in its Implementation Plan filing, it developed more specific work plans and estimates. These refined estimates, or "Job Estimates," are used in this report to represent the budgeted amount by project for a more meaningful comparison. For all the activities noted above, it should be anticipated that the costs associated with the risks (that were identified by PG&E in its original PSEP filing) involve large elements of uncertainty, such as water handling and pipeline cleaning, have materialized for many projects. As a result, costs have been significantly higher to complete strength testing and urban pipeline replacement than originally forecast. Also, other risks rarely encountered in Phase 1 are still possible for future phases and will create some forecast uncertainty. For example, as strength testing begins on long pipelines through Class 1 areas, which are also typically environmentally sensitive areas and are the single source of gas for large communities, such as the 100-mile long Line 177A in Eureka, there will be significant challenges to overcome, including how to serve the community when the pipe is out of service for months to conduct strength testing.

19. Cost Impacts of Unexpected or Unforeseen Items

What, if any, significant unexpected or unforeseen items did PG&E encounter in undertaking the projects and what were the resulting cost impacts on a project-by-project basis?

Response

Table 19-1 of the Appendix provides PG&E's most recent risk management assessment with a project-by-project analysis of unexpected or unforeseen items that have affected 2013 completed projects and the resulting cost and schedule impacts and identifies ways in which PG&E is addressing these risks on an ongoing basis by incorporating the lessons learned into project delivery processes.

PSEP's risk management process maintains risk registers at both an individual project level and for the program as a whole. A designated risk management committee reviews the results of risk analysis on a monthly basis and takes action to ensure that issue remediation and risk mitigation activities are appropriately prioritized and aligned across program workstreams.

For projects completed in 2013, PG&E identified that "Changes After IFB (Issue for Bid)"[19] and "Productivity Impacts"[20] caused the greatest cost increases totaling approximately $4.7 million and $3.35 million, respectively. "Productivity Impacts" and "Unexpected Condition of Pipe, Valves or Fittings"[21] accounted for the greatest number of schedule day delays totaling 280 and 156 days, respectively. The majority of these cost and schedule impacts were associated with risks realized on four projects previously scheduled for completion in 2012 but delayed into 2013. Excluding these projects to better identify realized risks associated with 2013 planned projects, analysis identified "Changes After IFB" and "Unexpected Condition of Pipe, Valves or Fittings" as having caused the greatest cost increases overall, but with significantly lower impacts totaling approximately $1.12 million and $0.68 million, respectively. Similar reductions

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19 Any scope changes made to the project after IFB.

20 Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.

21 Pipe, valves or fittings may be leaking or faulty requiring additional work to repair or replace them, not including linear indications on the pipe.

were also identified for schedule impacts under this analysis with "Productivity Impacts" and "Unexpected Condition of Pipe, Valves or Fittings" accounting for the greatest number of schedule day delays with a total of 244 and 24 days of delay, respectively. Significantly, the second quarter risk analysis highlighted a material reduction in impacts associated with permitting,[22] due to improvements in the identification of permits with long lead times, regional construction planning with Alliance construction contractors, and the coordination of projects to reduce overall permit quantities.

This report identified the following main risk areas (with associated impacts) with recommendations:

- **Changes After IFB (Cost and Schedule)**
  - Results: Four replacement projects that continued from 2012 into 2013 due to various construction complexities were a major driver behind the impact of this realized risk in 2013. The cost impact on 2013 scheduled projects, excluding the impact of these delayed 2012 projects, was significantly lower. The identification of the common causes of changes that affected 2012 projects, as previously recommended within prior risk management analyses, was successfully used to inform planning activities for 2013 projects. The ongoing tracking of these risks on individual project risk registers enabled project teams to better anticipate and reduce potential impacts.
  - Recommendations: Continue monitoring of this risk within project risk registers along with earlier commencement of pre-construction activities in coordination with Construction Management and Alliance contractors.
- **Productivity Impacts (Cost and Schedule)**
  - Results: Primarily affected the delayed 2012 pipe replacement projects noted above and two valve automation projects that experienced schedule issues as a result of their combination with larger non-PSEP station rebuild projects. A cost/benefit analysis determined that the anticipated cost savings from combining these projects were outweighed by the potential schedule impacts. Greater regional coordination,

[22] Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g., limited working hours, limited access, delays in issuance, etc.).

particularly with Alliance contractors, also enabled construction resources to move efficiently between projects and workstreams, thereby reducing the impact of this realized risk in 2013.

– Recommendations: Continue the increased coordination of PSEP workstream activities with regional construction resources, including combination with non-PSEP activities when appropriate opportunities are identified. Continue to build portfolio of 'back-up' projects available to commence construction, if required, to meet annual workstream targets.

- **Unexpected Conditions of Pipe, Valves or Fittings (Cost and Schedule)**

– Results: Impacts related to this risk included pipe damage by farming equipment on a strength test project, and the identification of a leaking valve that required replacement just prior to scheduled tie-in on a pipe replacement project. This risk and the manner in which it may materialize and impact a specific project is being identified as part of planning activities that also incorporate the local knowledge of gas transmission personnel (e.g., the recognition that there is a potential for pipe leaks during a specific strength test due to a history of agricultural land use and prior instances of damage from farming equipment on the pipeline). However the exact timing, location and extent of impact are highly variable and have the potential to materially impact project cost and schedules (e.g., it may take several days and significant resources to locate a leak).

– Recommendations: Continue the monitoring of this risk using project risk registers, in particular for projects on the same line, in close proximity, or with similar pipeline attributes (e.g., shallow pipe). Continue to carry forward lessons learned from these and prior occurrences to improve the efficiency of response to future line damage or leaks (e.g., determining damage/leak location).

- **Field Conditions Differ from Expected Conditions[23] (Cost)**

– Results: The impact of this risk primarily affected 2013 strength test projects, however to a lesser extent than 2012 projects. This risk was

23 Expected conditions based upon availab le "as-built" drawings and/or Geographic Information System (GIS) data.

generally realized due to the extensive passage of time since installation, the extent of subsequent field changes, and the availability and completeness of as-built documentation. The carry forward of lessons learned into 2013 has included greater consistency in the determination of design drawing tolerances and level of detail and an increased focus on the quality of surveying and potholing/mark and locate activities, particularly when undertaken to address specific project uncertainties. In addition, a recent revision of PG&E's "Dig-In" Prevention Policy now requires construction contractors to perform sub-surface validation using multiple technologies, including ground-penetrating radar.

– Recommendations: It is recognized that this risk cannot be fully mitigated and it is recommended that project-level risk assessments and implementation of mitigation activities continue.

PG&E will continue to supplement this risk analysis with the results of the remaining 2013 PSEP projects. Table 19-2 provides a reference for the specific data points requested in Question 19 to their corresponding column in Table 19-1 of the Appendix. Additional data points are included for context in navigating the tables.

TABLE 19-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 19-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Region	Region where line is located.
Risk	Categorization of risk factor affecting the project.
Description	Description of risk factor.
Cost Impact ($)	Impact of risk to project cost.
Schedule Impact (Days)	Impact of risk to schedule in number of days.
> 10% Variance	Projects greater than 10 percent over Job Estimate.
Comments	Description of how risk factor materialized.

20. Program Amount Authorized and Spent

Provide a table showing the total amount authorized for recovery from ratepayers and the total amount spent by PG&E year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 20-1, in the Appendix, shows the total amount spent by PG&E year-to-date through the second quarter ended June 30, 2013, shown by month and broken down by activity. Amounts authorized for customer recovery are provided at the program activity level, consistent with the presentation in Attachment E of the December 2012 CPUC PSEP Decision.

21. Shareholder Costs Absorbed

Provide a table showing the total amount of costs that shareholders will absorb year-to-date shown by month and broken down activity (e.g., hydrotesting, pipe replacement).

Response

Table 20-1 included in response to Question 20 provides the total amount of costs that shareholders have absorbed year-to-date through the second quarter ended June 30, 2013, shown by month and broken down by activity. Amounts funded by shareholders are provided at the program activity level, consistent with the presentation in Attachment E to the December 2012 CPUC PSEP Decision.

To date, no activity has incurred allowable costs in excess of its total Phase 1 authorized amount.

22. Forecast vs. Actual Mileage – Replacements

Provide a table showing the total mileage of pipe PG&E forecast to replace in R.11-02-019 and the mileage PG&E has replaced year-to-date. Identify the location, Line #, milepost, Class of the pipe replaced. Indicate whether the pipe is located in a High Consequence Area.

Response

As of June 30, 2013, PG&E has replaced over 59 miles of gas transmission pipeline as part of the PSEP program. Table 22-1, below, provides the total pipeline miles PG&E forecast to replace in Rulemaking 11-02-019 and the total pipeline miles replaced (from program inception through the end of this reporting period). Table 22-2 of the Appendix provides detail on 12 projects completed (tied-in) in 2013 through the end of this reporting period and identifies the location, pipeline number, milepost, class of the pipeline section replaced, and indicates whether the pipeline is located in a HCA on a project-by-project basis. Table 22-3 provides a reference for the specific data points requested in Question 22 to their corresponding columns in Table 22-2 in the Appendix. Additional data points are included for context in navigating the tables.

TABLE 22-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL PIPELINE MILES REPLACED – FORECAST AND ACTUAL
APRIL 1, 2011 – JUNE 30, 2013

Pipeline Replacement	2011 Actual	2012 Actual	2013 Actual YTD	2013 Forecast
Forecast R.11-02-019	0.3	39.0	n/a	64.0
Replaced and Tied-In(a)	–	31.5	4.3	n/a
Installed Pending Tie-In	0.3	8.7	14.5	n/a
Total	**0.3**	**40.2**	**18.9**	**64.0**

(a) Mileage reflects pipeline lengths identified in PSEP filing and is subject to final engineering review of "as-built" drawings to validate segment-level completion of PSEP scope.

TABLE 22-3
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 22-2 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Miles Completed	Miles of pipeline replaced or tested.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date	Date pipe became operational and project completed.

23. Forecast vs. Actual Mileage – Strength Testing

Provide a table showing the mileage of pipe PG&E forecast to hydrotest in R.11-02-019 and the mileage PG&E has tested year-to-date. Identify the location, Line #, milepost, Class of the pipe tested. Indicate whether the pipe is located in a High Consequence Area.

Response

As of June 30, 2013, PG&E has completed strength testing on 485 miles of gas transmission pipeline since the inception of the PSEP program, including the validation of the records of over 108 miles of prior hydrotests as meeting the "traceable, verifiable and complete" standard. Table 23-1 below, provides the total pipeline miles PG&E forecast to strength test in Rulemaking 11-02-019 and the total strength tested through the end of this reporting period. Table 23-2 of the Appendix provides detail on 20 completed projects and identifies the location, pipeline number, milepost, class of the pipe tested, and indicates whether the pipe is located in a HCA on a project-by-project basis. Table 23-3 provides a reference for the specific data points requested in Question 23 to their corresponding columns in Table 23-2 in the Appendix. Additional data points are included for context in navigating the tables.

TABLE 23-1
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL PIPELINE MILES STRENGTH TESTED – FORECAST AND ACTUAL
APRIL 1, 2011 – JUNE 30, 2013

Pipeline Strength Testing	2011 Actual	2012 Actual	2013 Actual YTD	2013 Forecast
Forecast R.11-02-019	236.0	185.0	n/a	204.0
Actual Tested and Tied-In(a)	163.6	176.2	36.5	n/a
Records Validated(b)	50.9	27.8	29.9	n/a
Total Tied-In and Records Validated	**214.5**	**204.0**	**66.4**	**204.0**

(a) Mileage reflects pipeline lengths identified in PSEP filing and is subject to final engineering review of 'as-built' drawings to validate segment-level completion of PSEP scope.

(b) Includes pipeline miles for which records of a prior Hydrotest were validated as meeting the traceable, verifiable and complete records standard.

TABLE 23-3
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 23-2 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Miles Completed	Miles of pipeline replaced or tested.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date	Date pipe became operational and project completed.

24. Public Outreach Costs

Provide the costs of the public outreach PG&E has incurred year-to-date by month as compared to the amount authorized. Explain in detail what public outreach activities PG&E has engaged in.

Response

Customer Outreach is included as an integral part of each of PG&E's PSEP construction projects. Table 24-1 below provides customer and community outreach costs incurred since program inception in 2011, shown annually for 2011-2012, and monthly during 2013 (see Table 24-1 below.)

TABLE 24-1
PACIFIC GAS AND ELECTRIC COMPANY
PUBLIC OUTREACH COSTS
APRIL 1, 2011 – JUNE 30, 2013
(IN MILLIONS OF DOLLARS)

2011 Total	2012 Total	13-Jan	13-Feb	13-Mar	13-Apr	13-May	13-Jun	YTD 2013 Total
$2.62	$4.54	$0.36	$0.35	$0.38	$0.38	$0.35	$0.38	$2.20

The CPUC's PSEP decision approved customer outreach costs, including governmental outreach, within individual project estimated costs. PG&E's estimated customer outreach costs varied by workstream driven by the nature of the work and were based upon a percentage of project costs before project management and escalation. For pipeline replacement and strength testing project the customer outreach estimate percentage was 2.9 percent, and for valve automation projects the percentage was 0.54 percent. Specific monthly authorized amounts cannot be accurately determined from the CPUC decision due to individual project durations and the timing of activities within projects; however, PG&E notes that customer outreach costs have averaged approximately 1 percent of total project costs. PG&E has been able to reduce initial estimated customer outreach costs through effective project planning, the use of external contractors to create materials, send and manage customer outreach activities and has improved the integration of these activities within existing PG&E processes and resources. Public outreach activities undertaken by PSEP have included the use of Interactive Voice Responses (IVR, or automated phone notifications), letters, open houses, signage, door-to-door canvassing, one-on-one customer phone calls and meetings, and customer group presentations. As of June 30, 2013, 27 Open Houses have been hosted, approximately 88,853 letters have been mailed, and 131,402 IVR calls have been made to customers impacted by PSEP work.

Customer Outreach activities are managed on a consistent basis across PSEP workstreams by a dedicated team of Customer Impact Specialists within PG&E's Customer Care organization. Each project follows a standardized process for customer outreach which includes, but is not limited to:

- Site walk with project team to identify customer impacts.
- Letter to impacted customers.
- Invitation to an open house, hosted within the affected project area.
- Work location signage prior to mobilization.
- IVR sent to area customers prior to significant activities (e.g., venting/release of natural gas).
- Additional customer outreach and accommodations as dictated by the nature of the project (e.g., temporary relocation for nitrogen strength test).
- Local customer canvassing to identify and incorporate feedback into ongoing procedures.

In this reporting period, the Customer Outreach team added another touch point to the communications process for some projects. In effort to increase Open House attendance, the Customer Outreach team sent out an IVR reminder and/or canvassed an impacted area, inviting customers to attend the Open House in their area. The IVR reminded customers of the date, time and location of the Open House. Canvassing visits involved leaving behind door hangers that included copies of the letter with Open House invitation that these customers had already received. Only a minor increase in attendance to Open Houses has been seen as a result.

Customer Outreach has begun to look for opportunities to attend Homeowners Association (HOA) meetings where appropriate. The Customer Outreach and project team has met with various HOA boards/groups with regards to the L-109 replacement project in order to lay the framework for the work expected to start in 2014. In May, the teams met with an HOA in San Francisco to present project maps and explain schedule and potential customer impacts of

Strength Test T-13C, and another in Newark for T-28. Nearly 50 residents attended.

The Customer Outreach team is often on site during project work to ensure that impacts to customers and local communities are minimized. On a 2013 pipe replacement project on Line-138 in Fresno, Customer Outreach worked closely with local businesses to ensure minimum disruption due to the sound of scheduled gas venting activities. When the needs of local businesses changed at short notice, PG&E was able to delay the venting activities. Customer Outreach visited the affected customers to confirm the updated schedule and ensure that the potential disruption would be avoided.

In addition and as part of project design and planning activities, PG&E identifies and reviews specific customer impacts. Where customer loads are significant, PG&E will work with assigned account representatives to schedule activities to minimize the impact to customers. This may involve scheduling tests outside of agricultural peak periods or scheduling project activities to occur outside of school hours or key events.

25. Service Outage Performance

Describe (e.g., provide date(s), location, Line #) all planned and unplanned service outages PG&E experienced in conducting the project work and explain how PG&E addressed customer needs during the outages. Were customers notified of any outages beforehand?

Response

PG&E has successfully conducted gas transmission pipeline outages supporting 41 completed construction projects in 2013, with minimal impact to customer service. Tables 22-2 and 23-2 provide pipeline outage dates, locations and pipeline numbers, on a project-by-project basis for completed pipe replacement (12) and strength test projects (20). Table 25-1 of the Appendix supplements these tables by providing information for nine completed valve automation and in-line inspection projects in 2013. Table 25-2 provides a reference for the specific data points requested in Question 25 to their corresponding column in Table 25-1 in the Appendix. Additional data points are included for context in navigating the tables.

TABLE 25-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 25-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers supporting PG&E's August 26, 2011 filing.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers supporting PG&E's August 26, 2011 filing.
Miles Completed/Valves Automated	Miles of pipeline strength tested, replaced or number of valves automated.
Line	Pipeline identifier.
MP1	Beginning project mile point.
MP2	Ending project mile point.
City	Location of project.
HCA	Project includes a High Consequence Area.
Class Code	Class of pipeline included in project.
Clearance Date	Date pipe was cleared and work authorized to begin.
Tie-In Date	Date pipe became operational and project completed.

As previously mentioned, initial project design and planning activities include identification of potential customer impacts. PG&E specifically works to minimize the impact to customers and schedules work where possible to avoid customer outages by using existing system redundancies (e.g., cross compression, parallel pipes or back-feeds to maintain customer service). This is a primary reason why many construction activities cannot take place during seasonal winter gas demand periods.

PG&E has previously identified that with the previous level of equipment and manpower it would not be possible to complete the entire scope of the Implementation Plan without impacting customer service in certain circumstances. To mitigate this potential customer impact, PG&E increased its LNG/CNG portable program to enable the increased avoidance of customer outages. Rising from 22 units in 2010 to 177 units targeted in 2013, the program continues to be an integral part of project planning and scheduling activities has successfully met the significantly increasing demand for its services—supporting 2,410 customer tap days through the end of June in 2013 using portable CNG equipment, compared to 2,088 customer tap days for the same time period in 2012 (note: 354 customer tap days were supported in 2010). Expressed slightly differently, this represents support at over 13 separate locations daily on average and reached as high as 34 separate locations daily in May. In addition, the group has already successfully delivered one LNG operation in 2013 at a very important electric vehicle manufacturing facility. This operation involved 41 hours of continuous support over a weekend with triple redundancy to deliver on PG&E's commitment to provide continuous and uninterrupted flow of gas to this customer. Current plans for 2013 include up to five more LNG operations during the rest of 2013.

Where customer loads are significant, PG&E has worked with assigned account representatives to schedule activities to minimize impact and potentially avoid the significant costs associated with LNG support operations. This has involved scheduling tests outside of agricultural peak periods and commercial work hours and scheduling project activities to occur outside of school hours or key events. For example, during the current reporting period Strength Test T-217 in Belmont was rescheduled from May to June and July to accommodate customer preference to avoid the use of CNG trailers on their property. Pushing these dates out farther avoided the need for CNG and increased the available space for staging on the customer's property. Other examples include:

- Strength Test T-207 in the Central Coast area was scheduled to take advantage of an existing planned period when a winery did not require service;
- Strength Tests T-331A, T-331B, T-333, and T-223 in the Yuba City area, were rescheduled to avoid impacts to commercial prune dryer operations;
- PG&E worked with a large commercial customer to identify a weekend during which an outage could be scheduled to support Strength test T-310-14 in Crockett.

26. Forecast Projects Not Completed or Replaced

Describe or provide a specific reference to PG&E's work papers of the projects that were not completed or replaced by a higher priority project and show the uncompleted project's associated costs. Compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, as required by Ordering Paragraph 6.

Response

PG&E estimates 28 projects that were originally planned to be executed in the first half of 2013 may no longer be required (e.g., identification and validation of the records of a prior strength test). Table 26-1 of the Appendix includes a list of previously planned 2013 projects, with specific reference to prior PG&E work papers that were not completed or replaced by a higher priority project in this reporting period.[24]

Considering the natural evolution of the specific project work scope within the programs included in the August 2011 Implementation Plan filing and the preliminary nature of the associated cost estimates at the time (i.e., program level estimates based on limited project definition and design completion), PG&E is unable to quantify potential reductions to the adopted amounts (set out in Attachment E of D.12-12-030) until it completes its detailed segment analysis and updated estimates associated with the Update Application later this year. Following the completion of this Update Application, PG&E will be able to reconcile its incurred PSEP costs with the adopted program amounts in Decision 12-12-030, and compute the corresponding reduction to the Implementation Plan adopted amounts set out in Attachment E, if any, as required by Ordering Paragraph 6.

Table 26-2 provides a reference for the specific data points requested in Question 26 to their corresponding column in Table 26-1 of the Appendix. Additional data points are included for context in navigating the tables.

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[24] For similar project data related to 2011 and 2012 projects refer to PSEP Compliance Report 2013-01.

TABLE 26-2
PACIFIC GAS AND ELECTRIC COMPANY
DATA POINT/TABLE 26-1 COLUMN REFERENCE

Column Name	Description
Line #	Reference number for this report.
PSEP Filing PSRS	PSRS number provided in workpapers from proceedings.
New PSRS	New PSRS number resulting from project split or addition.
Project Description	Order Description provided in workpapers from proceedings.
PSEP Filing Year	Year project anticipated to begin as stated in the filing.
Current Status	Current project status.
Comments	High-level descriptions for projects that were not completed or replaced.

27. Project Cost Recovery

Provide a clear explanation, for each project for which expenditures have been incurred, of how the project is necessary to comply with PSEP requirements rather than being included among projects that are already funded in D.11-04-031.

Response

The scope of PG&E's PSEP is based upon pipeline segments previously identified as not having been strength tested, and/or without traceable, verifiable and complete records of such a test. The specific actions to be taken under PSEP and the prioritization of such projects are based upon the results of consistently applying a sequential decision process (decision tree) to pipeline segment features information. PG&E's original PSEP scope was based upon pipeline data as of April 2011 and PG&E anticipated that the update and completion of the review of pipeline segment information would alter the scope of PSEP's projects. During the PSEP proceeding, PG&E confirmed that the PSEP scope as filed excluded any pipeline segments previously included within other recovery mechanisms, including projects approved as part of the Gas Accord V Settlement in Decision 11-04-031.

To the extent that additional scope has been added to a PSEP project that does not meet the PSEP Decision Tree criteria (or it is a non-adjacent non-HCA Class 1 or 2 pipe segment) PG&E has identified and is separately tracking costs associated with this increased project scope. Examples would be an increase in pipeline diameter to support future capacity needs or a project identified in D.11-04-031 is engineered, permitted and constructed with an adjacent PSEP project to capture efficiencies.

PG&E will provide the specific engineering decision tree results supporting the actions being taken within the PSEP program upon completion of its MAOP records validation process as part of its subsequent Update Application.

28. Record Improvement Efforts Progress

Progress report on record improvement efforts, including report on costs absorbed by shareholders.

Response

PG&E's Mariner Project (formerly referred to as the "GTAM Project"), is part of the Pipeline Records Integration Program proposed in the PSEP filing. Mariner costs are included in Table 20-1 and are completely funded by shareholders in compliance with Decision 11-06-017. The goal of the Mariner Project is to further enhance the safety and reliability of PG&E's gas transmission system through increased access to pipeline systems data, integrated risk management and integrity management analytics, and improved work management. Specifically, the Mariner Project will:

- Improve data availability by eliminating paper-based work processes and installing tools to enable the electronic collection, processing, review, analysis, and integration of pipeline systems data.
- Improve PG&E's pipeline risk management capabilities by integrating different types of asset data into a single system.
- Support PG&E's Pipeline Safety Enhancement Plan and address the CPUC and National Transportation Safety Board concerns by enabling and supporting asset data that are traceable, verifiable and complete.
- Generate operational efficiencies related to: the time required to enter and upload data into the system, the time required to locate and collect information maintained in different offices and different records management systems, the time required to correlate and analyze engineering data, and the time associated with field force dispatch as work assignments can be automated and optimized to minimize travel. Full realization of benefits is dependent on the integration of the various components of the Mariner Project.

The Mariner project made progress in several functional areas by providing new mobile devices to field personnel, replacing outdated hardware, providing access to electronic maps, deploying integrated risk management tools, and converting records as part of the MAOP Validation Project. The Mariner Project is also progressing toward integrating work management and asset systems, and mobilizing corrective and preventative maintenance processes.

In PG&E's August 26, 2011 prepared testimony, PG&E described four phases of project development. This report lists the activities that were included in each phase and provides a summary of the activities completed as of June 30, 2013.

<u>Mariner Project Phase 0: Planning and System Architecture Design</u>

Planned Timing ~ Q1 2011 – Q2 2012

Phase 0 Key Activities:

1. Assess industry best practices for management of gas transmission data
2. Evaluate various hardware, software and data models
3. Assess current information technology architecture and design target state architecture
4. Move leak survey reporting data from Integrated Gas Information System (IGIS) to work management system (SAP)
5. Deploy mobile workstations to Locate and Mark and Leak Survey workers

<u>Mariner Project Phase 1: Implement New Technology to Support Mariner Project for Pipeline Assets</u>

Planned Timing ~ Q1 2011 – Q3 2013

Phase 1 Key Activities:

1. Implement a linear event-based GIS system
2. Implement additional mobile technologies for gas maintenance / inspection and leak survey/reporting
3. Integrate GIS and SAP
4. Implement leak-survey and reporting workflows in SAP
5. Enable remote access to pipeline asset data and tools to record leak information in the field
6. Implement Pipeline Integrity/Risk Management tools
7. Deploy document management system
8. Implement a technology platform and work processes to integrate material ordering, receiving, inspection, issuing, installation and maintenance information

Mariner Project Phase 2: Implement New Technology to Support Mariner Project for Corrosion and Line Equipment Assets

Planned Timing ~ Q2 2013 – Q3 2014

Phase 2 Key Activities:

1. Extract, convert and import legacy data to a common SAP platform
2. Implement processes and technology to record materials installed on pipeline replacement projects
3. Integrate SAP and GIS systems for pipeline, line equipment and corrosion data
4. Implement workflows in SAP for pipeline, line equipment and corrosion maintenance and inspections
5. Enable mobile technology for work notifications and field completion for pipeline, line equipment and corrosion maintenance and inspections
6. Implement new tools to manage the gas transmission project portfolio
7. Develop interfaces between GIS and Gas System planning software

Mariner Project Phase 3: Implement New Technology to Support Mariner Project for Station Assets

Planned Timing ~ Q2 2014 – Q1 2015

Phase 3 Key Activities:

1. Extract, convert and import legacy station asset data to a common SAP platform
2. Integrate station asset data within the Core Systems
3. Implement automated workflows in SAP for station asset maintenance and inspections
4. Enable mobile applications for creating work notifications and completing field work for station asset maintenance
5. Deploy a mobile GIS system
6. Implement the SAP Project Portfolio Module to manage the gas capital projects portfolio

The following section details work and progress to date by each functional area affected by the Mariner Project.

Functional Area	Work Completed (as of June 30, 2013)	Mariner Project Phases
Leak Survey	**<u>Project Description</u>** The Leak Survey initiative replaced outdate mobile technology (EZTech phones) and paper forms with new mobile tablet devices, supported by new Leak Survey software and improved processes. The initiative will complete a system wide move of Leak Survey maintenance plans from various Systems into SAP. **<u>Progress and Accomplishments</u>** • Developed new Android application to document findings of leak survey work. • Piloted Android application and Android tablet. • Deployed over 166 tablet devices to Surveyors in 17 divisions, who were trained on the software, new processes and use of the new devices. • New Leak Survey software records leaks information remotely, eliminating the need for paper forms and provides more accurate records through improved business rules and data validation. **<u>Business Benefits</u>** • Enhanced functionality provided on improved, more user friendly equipment. • Ease of data entry and availability of digital maps and forms will reduce need for paper. • Digitize form will ensure verifiable and traceable process. • Integrated system for managing maintenance plans, updating survey cycles and capturing survey and leak data. • Greater visibility of what work is still outstanding and in need of being scheduled and/or dispatched.	**<u>Phases 0 and 1</u>**
Locate and Mark	**<u>Project Description</u>** Replaced legacy mobile technology (5-year old non-ruggedized laptops) with new mobile tablet devices and updated processes with access to current facilities maps. **<u>Progress and Accomplishments</u>** • Developed new Android application and map viewer for processing Locate and Mark tickets. • Piloted Android application. • Deployed Android tablets and new application to 136 Locators in 17 divisions. **<u>Business Benefits</u>** • Enhanced functionality provided on improved, more user friendly equipment including integrated camera enabling enhanced image attachments and improving sync capabilities with IRTH application. • Ease of data entry and availability of digital maps and forms will reduce need for paper. • Improved device connectivity and integrated tools required tools will improve efficiency. • Access to improved electronic Gas and Electric Mapping System (GEMS) maps.	**<u>Phase 0</u>**

<table>
<tr><th>Functional Area</th><th>Work Completed (as of June 30, 2013)</th><th>Mariner Project Phases</th></tr>
<tr><td>Corrective Maintenance</td><td><u>Project Description</u>
This effort provides for an accurate and complete dataset of information recorded in IGIS and other corrective maintenance history to be included in SAP.

<u>Progress and Accomplishments</u>
• Approximately 33K transmission leak related-records scanned and ready for SAP and Documentum.
• Built and Tested the following: SAP Program to include meta data in Documentum; conversion programs to include open and closed leaks from the IGIS and PC Leaks system; the Transmission scanned Legacy records (A-Forms); SAP Search Program to find documents in Documentum; the Corrective Leak process in SAP.
• Designed and created the new SAP solution including new database fields.

<u>Business Benefits</u>
• Integrated corrective maintenance process in SAP.
• Reduce cycle time for leak records entry.
• Sustain data accuracy and integrity due to data validation controls based on business rules.
• Enterprise enabler for future mobility.
• Provide system-wide visibility of the corrective process through improved reporting.
• Consistent use of leak and other forms will reduce unnecessary corrections and reviews.</td><td><u>Phases 0 and 1</u></td></tr>
<tr><td>Records Management</td><td><u>Project Description</u>
This effort sets up the IT structure needed to migrate corrective and preventative maintenance records to Documentum. Enables integration with core GT GIS and SAP systems to ensure traceable, verifiable and complete records.

<u>Progress and Accomplishments</u>
• Set up new Documentum servers, installed software and configured for future use.
• Imaged and uploaded approximately 33,000 Gas Transmission leak documents.
• Imaged and uploaded approximately 163,000 Preventive Maintenance Records related to Regulators, Valve Maintenance and Cathodic Protection processes, not including district-maintained records.
• Code to link images to Asset Registry in SAP is being finalized.

<u>Business Benefits</u>
• Enable enhanced traceability through direct linkage between records in Documentum, SAP asset registry and GIS.
• Enhanced access to system records due to centralization
• Greater ability for reporting.</td><td><u>Phase 1</u></td></tr>
</table>

<table>
<tr><th>Functional Area</th><th>Work Completed (as of June 30, 2013)</th><th>Mariner Project Phases</th></tr>
<tr><td>Mobile Technology Foundation</td><td><u>Project Description</u>
Deliver new mobile devices to gas maintenance and construction (M&C) field workers that will provide the capability to access electronic maps, as well as e-mail and technical information library through the PG&E intranet.

<u>Progress and Accomplishments</u>
• Developed a mobile GIS map viewer.
• Installation of synchronization tools to keep electronic field maps current.
• Piloted hardware and software solutions.
• Deployed 450 ruggedized portable computers, all required software licenses and truck mounts to securely hold computers in field crew trucks.
• Trained super users and field workers to ensure knowledge transfer and adoption by field workers.

<u>Business Benefits</u>
• Enhanced safety due to up to date electronic maps accessibility that will also improve crews ability to determine make safe and repair decisions expediently.
• Decrease in make safe time during emergency response with mobile device.
• Enable future mobile dispatching and bundling of work.</td><td><u>Phase 2</u></td></tr>
<tr><td>Preventive Maintenance</td><td><u>Project Description</u>
Paperless process for documenting preventative maintenance work performed in the field

<u>Progress and Accomplishments</u>
• Converted master data (valve types, etc.) and transactional data (regulator set points).
• Designed and created the new SAP solution including new database fields.
• Designed and created the new Ventyx screens for mobile data entry.
• Pilot and testing of the new SAP solution and mobile application have started. The Pilot delivers new mobile workforce management capabilities to the Gas Transmission and Regulation Mechanics, not including district-maintained records, in 4 divisions on a new version of Ventyx Service Suite.
• Electronic storage of gas distribution valve, regulator station, and rectifier maintenance and corrosion protection data has been implemented, excluding district-maintained records.

<u>Business Benefits</u>
• Business rules and validation in electronic forms will improve data quality and consistency.
• Increased productivity due to reduction in the number of data entry steps, streamlining processes, automation of reporting and asset update processes.
• Improved data quality and transparency of scheduled maintenance work.</td><td><u>Phase 2</u></td></tr>
</table>

Functional Area	Work Completed (as of June 30, 2013)	Mariner Project Phases
GIS	**<u>Project Description</u>** Deployment of new Gas Transmission GIS system using data from the MAOP project that uses Linear Asset Management and is integrated with SAP **<u>Progress and Accomplishments</u>** • Tested and validated the process for maintaining Linear Referencing data in GIS and SAP. • Kicked off the full deployment of GIS/SAP integration. **<u>Business Benefits</u>** • Synchronized data between SAP and GIS to provide "single version of the truth". • View work notifications spatially in GIS and add linear references to SAP assets. • Increased data quality control, minimizing data exceptions and discrepancies.	**<u>Phases 1, 2 and 3</u>**
Integrity Management	**<u>Project Description</u>** Implement industry standard "best practice" technology solutions to automate manual integrity analysis tasks and integrate tools with core enterprise systems **<u>Progress and Accomplishments</u>** • Gathered initial system requirements and mapping of "as-is" and "to-be" processes. • Finalized procurement process and contract for Class and HCA tools and Risk Modeling tools. • Rolled out a new HCA determination tool. • In the process of rolling out Class Location determination tool. **<u>Business Benefits</u>** • Enhanced performance in the areas of safety, reliability, compliance and work efficiency. • Increase productivity due to automation. • Traceable, verifiable, complete data. • Compliance with regulations.	**<u>Phase 1</u>**
Material Traceability	**<u>Project Description</u>** Establish a process to provide nomenclature and location data on specific gas components that are installed in our pipeline systems and trace selected materials used in pipelines and stations from sourced materials received by PG&E from installation to the As-Built process to enhance gas system safety. **<u>Progress and Accomplishments</u>** • Completed initial planning. • Finalized "as-is" and "to-be" process maps. • Executing analyze phase. **<u>Business Benefits</u>** • Enhanced safety, accountability, and asset management due to greater data quality collection controls. • Automation and improvement of material tracing.	**<u>Phases 0 and 1</u>**

29. Additional Relevant Information

Any additional relevant information not listed above as specified in hearing Exh. 2 at 8E-1 and 8E-2.

Response

PG&E considers that the information provided within this report covers all aspects previously outlined in *hearing Exh. 2 at 8E-1 and 8E-2.*

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS COMPLETED
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Order Number	Project Description	City	Construction Contractor	Mobilization Date	Tie-in Date	Job Estimate Amount	Total Cost	Labor Cost	Materials Cost	Contracts Cost	Other Cost	Variance to Budget	PSEP Disallowed Cost	Non-PSEP costs	>10% Over Budget	Comments
1	24022	24022	41482736	L-300A MP 352.3-391.2 ILI & ANALYSIS	Kettleman City	GT/GC	3-Apr-13	15-Apr-13	$ 1,484,526.00	$ 998,659.00	$ 293,356.00	$ 36,108.00	$ 649,519.00	$ 19,676.00	$ (485,867.00)	$ -	$ -	No	Please note that "GT/GC" means Gas Transmission - General Construction.
2	23825	26033	30842223	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Fresno	Snelson	30-Jul-12	6-Jun-13	$ 32,772,765.00	$ 31,863,573.00	$ 1,533,599.00	$ 5,570,290.00	$ 24,504,452.00	$ 255,232.00	$ (909,192.00)	$ 2,701,421.00	$ -	No	Delayed from 2012 to 2013 as a result of construction complexities requiring more time for engineering and planning.
3	23832	26029	30842215	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Fresno	Snelson	21-Aug-12	28-Feb-13	$ 35,520,000.00	$ 35,505,432.00	$ 1,293,165.00	$ 5,910,402.00	$ 25,541,821.00	$ 2,760,044.00	$ (14,568.00)	$ 345.00	$ -	No	Delayed tie-in from 2012 to 2013 due to additional Integrity Management (IM) tie-in and construction complications, including land acquisition delays.
4	23688	26045	30841472	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Oakley	Rockford	21-Sep-12	12-Jan-13	$ 13,961,750.00	$ 18,526,603.00	$ 1,164,699.00	$ 1,995,819.00	$ 14,486,619.00	$ 879,466.00	$ 4,564,853.00	$ 29,156.00	$ -	Yes	Delayed tie-in from 2012 to 2013 due to productivity impacts resulting from easement constraints during construction. Job Estimate (JE) created prior to project split into 3 portions for constructability reasons and then allocated to each project based on mileage. However, this method did not take into account the 2 additional mob/de-mob costs, site restoration costs and other site specific conditions that vary along the line. For the other 2 projects, planned for 2013 and 2014, new JEs will be created.
5	23724	25727	30842248	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Palo Alto/Stanford	ARB	4-Sep-12	19-Jun-13	$ 31,143,398.00	$ 38,977,767.00	$ 1,912,468.00	$ 2,618,293.00	$ 33,493,972.00	$ 953,034.00	$ 7,834,369.00	$ 64,494.00	$ -	Yes	
6	23365	23366	30847128	R-029 L-109 REPL 0.58 MI MP 9.27-9.87 Spread 6A	Mountain View	Snelson	20-Jul-12	18-Dec-12	$ 11,097,878.00	$ 12,975,635.00	$ 773,325.00	$ 651,278.00	$ 10,363,852.00	$ 1,187,180.00	$ 1,877,757.00	$ -	$ -	Yes	This portion of the original project was tied-in in 2012 with another 149 feet to be completed in 2013 because a school could not take the outage required for clearance in 2012; however, it has now been delayed until 2014 to coincide with other work on the line so that portion has been split to a separate project (PSRS 30791) and this portion is now being reported for completeness despite the 2012 tie-in date. Risks realized on the 2012 portion of this project were reported in Q1-13 Table 19-1.
7	23807	23807	30842178	R-041 DFM-1020-01 REPL 2.69mi MP 0.00-2.69 PH1 8" Dist.	Butte	GC	31-May-12	14-Jan-13	$ 2,515,322.00	$ 2,907,131.00	$ 692,521.00	$ 79,883.00	$ 84,526.00	$ 2,050,201.00	$ 391,809.00	$ 1,517,983.00	$ -	Yes	Accelerated from 2014 to 2012 and replaced with Distribution piping to align with PG&E's commitment to retire or replace 1,200 High Pressure Regulators (HPRs) by the end of 2012.
8	24909	24909	97000661	R-043 SP4Z RETIRE 0.22mi MP 8.18-8.43 PH1	Oakley	H&M	6-Mar-13	24-Apr-13	$ 259,825.00	$ 302,594.00	$ 95,445.00	$ 3,755.00	$ 242,563.00	$ (39,169.00)	$ 42,769.00	$ 228,167.00	$ -	Yes	Delayed from 2012 to 2013 for efficiency reasons to coordinate work with other PSEP projects in the Antioch Terminal Area.
9	23862	23862	30842187	R-071 DFM-1502-08 REPL 0.52MI MP 0.01-0.52 PH1	Yuba	GC	29-Oct-12	3-Jan-13	$ 769,377.00	$ 812,207.00	$ 498,598.00	$ 80,282.00	$ 110,944.00	$ 122,383.00	$ 42,830.00	$ 423,425.00	$ -	No	Accelerated from 2014 to 2012 to avoid a pressure reduction and to coordinate with Division work to convert to low pressure main and remove HPRs in 2012.
10	23874	26442	30906224	R-100 L-131 RETIRE 0.37MI MP 8.56-8.93 PH1	Oakley	H&M	6-Mar-13	24-Apr-13	$ 147,444.00	$ 131,152.00	$ 38,943.00	$ 3,929.00	$ 59,005.00	$ 29,275.00	$ (16,292.00)	$ 131,152.00	$ -	No	Added as new retirement project from filed test project to reduce redundant pipeline. Done in conjunction with R-043, R-114, T-015-12, and T-279-13.
11	N/A	25791	30894012	R-114 L-114 RETIRE 0.83 MP 8.18-8.92 PH1	Oakley	H&M	6-Mar-13	24-Apr-13	$ 264,013.00	$ 450,924.00	$ 105,231.00	$ 12,890.00	$ 328,633.00	$ 4,170.00	$ 186,911.00	$ -	$ -	Yes	Added as new project to replacement workstream to retire this portion of L-114_2 due to redundancy. Completed in conjunction with R-100, R-043, T-015-12, T-279-13.
12	24902	27712	30935230	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	Sacramento	GT/GC	8-May-13	14-Jun-13	$ 998,097.00	$ 1,189,841.00	$ 689,737.00	$ 150,642.00	$ 200,656.00	$ 148,806.00	$ 191,744.00	$ -	$ -	Yes	Delayed from 2012 to 2013 for efficiency reasons to coordinate work with L-119B Tests planned in 2013.
13	24903	24903	30939632	R-139 L-131Y REPL 0.01MI MP 0.53-0.54 PH1	Brannan Isld Park	GT/GC	25-Apr-13	10-May-13	$ 578,745.00	$ 501,166.00	$ 342,304.00	$ 10,377.00	$ 87,526.00	$ 60,959.00	$ (77,579.00)	$ 171,881.00	$ -	No	Delayed from 2012 to 2013 to allow more time for engineering after a portion of the line was deactivated.
14	23874	25841	41613030	T-015-12, Line L-131_2, Oakley	Oakley	H&M	6-Mar-13	1-May-13	$ 1,991,409.00	$ 1,093,382.00	$ 270,737.00	$ 12,472.00	$ 1,226,751.00	$ (416,578.00)	$ (898,027.00)	$ 1,093,381.00	$ -	No	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management (IM) in 2012.
15	24537	28473	41801221	T-038B-11, Line L-132, Daly City	Daly City	Snelson	00-Jan-00	25-Feb-13	$ -	$ 306,407.00	$ 30,918.00	$	$ 267,585.00	$ 7,904.00	$ 306,407.00	$ 306,407.00	$ -	N/A	Delayed from 2011 to 2013 and split from T-038-11 (PSRS 24530) to coordinate this pipeline section within Martin Station within that station rebuild project . No separate JE because this was a joint project.
16	23510	25902	41600053	T-046-12, Line L-138, Fresno	Fresno	Snelson	12-Apr-13	24-May-13	$ 2,587,895.00	$ 2,270,003.00	$ 347,357.00	$ 61,240.00	$ 1,855,138.00	$ 6,268.00	$ (317,892.00)	$ -	$ -	No	Delayed from 2012 to 2013 to minimize customer impact during clearance.
17	23554	25866	41600069	T-082-12, Line L-119B, Sacramento	Sacramento	SE Pipe Line	28-Mar-13	27-Apr-13	$ 1,430,196.00	$ 1,112,574.00	$ 375,897.00	$ 14,421.00	$ 680,264.00	$ 41,992.00	$ (317,622.00)	$ -	$ -	No	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012.
18	24216	25884	41617946	T-093-12, Line L-210C, Vallejo	Vallejo	ARB	1-Apr-13	4-May-13	$ 2,132,881.00	$ 2,276,631.00	$ 762,846.00	$ 41,008.00	$ 1,391,058.00	$ 81,719.00	$ 143,750.00	$ 82,100.00	$ -	No	Delayed from 2012 to 2013 because large customer could not take an outage in 2012.
19	23905	25904	41622643	T-101-12, Line DFM-3010-01, Antioch	Antioch	ARB	21-Jan-13	4-Feb-13	$ 1,664,377.00	$ 1,154,038.00	$ 329,529.00	$ 5,570.00	$ 804,216.00	$ 14,723.00	$ (510,339.00)	$ 1,091,532.00	$ -	No	Delayed from 2012 to 2013 to coordinate with the customer planned shutdown during hydrotest.
20	23524	28395	41756005	T-206-13, Line L-187, King City	King City	Underground	8-Apr-13	20-May-13	$ 2,495,220.00	$ 2,536,806.00	$ 544,422.00	$ 33,276.00	$ 1,933,981.00	$ 25,127.00	$ 41,586.00	$ 771,125.00	$ -	No	
21	23524	28407	41756006	T-207-13, Line L-187, Greenfield	Greenfield	Underground	8-Apr-13	13-Jun-13	$ 2,103,598.00	$ 1,820,160.00	$ 339,704.00	$ 10,782.00	$ 1,458,712.00	$ 10,962.00	$ (283,438.00)	$ 1,054,281.00	$ -	No	
22	23524	28408	41756007	T-208A-13, Line L-187, Soledad	Soledad	Underground	22-May-13	28-Jun-13	$ 3,536,097.00	$ 1,114,131.00	$ 313,699.00	$ 29,194.00	$ 754,761.00	$ 16,477.00	$ (2,421,966.00)	$ 56,252.00	$ -	No	JE includes T-208A-13, T-208B-13 and T-208C-13 because split occurred post estimate. T-208A-13 is ~29% of original length and T-208B-13, T-208C-13 tie-in in Q3.
23	23532	27604	41744017	T-218-13, Line L-021B, Napa	Napa	ARB	29-Apr-13	8-Jun-13	$ 2,300,066.00	$ 1,932,059.00	$ 572,971.00	$ 17,859.00	$ 1,275,020.00	$ 66,209.00	$ (368,007.00)	$ -	$ -	No	
24	23565	27609	41744230	T-224A-13, Line DFM-0604-01, Vacaville	Vacaville	Barnard	21-May-13	21-Jun-13	$ 2,318,531.00	$ 1,341,933.00	$ 307,719.00	$ 10,285.00	$ 992,161.00	$ 31,768.00	$ (976,598.00)	$ 1,340,316.00	$ -	No	
25	23876	27613	41744236	T-226-13, Line DFM-0817-01, San Jose	San Jose	SE Pipe Line	11-Mar-13	4-Apr-13	$ 1,950,753.00	$ 1,615,096.00	$ 485,582.00	$ 12,059.00	$ 1,065,062.00	$ 52,393.00	$ (335,657.00)	$ 213,996.00	$ -	No	
26	23550	27615	41748704	T-229A-13, Line L-118B, Madera	Madera	Snelson	17-May-13	21-Jun-13	$ 2,541,348.00	$ 1,914,620.00	$ 443,955.00	$ 22,935.00	$ 1,444,991.00	$ 2,739.00	$ (626,728.00)	$ 1,912,072.00	$ -	No	JE includes both T-229A-13 and T-229C-13 because split occurred post estimate. T-229A-13 is ~11% of original length and T-229C-13 ties in Q3.
27	N/A	28245	97001461	T-279-13, Line SP4Z, Antioch	Antioch	H&M	6-Mar-13	1-May-13	$ 1,448,197.00	$ 1,359,168.00	$ 237,888.00	$ 7,883.00	$ 687,760.00	$ 425,637.00	$ (89,029.00)	$ -	$ -	No	Added as new project to be tied in to L-131 and tested in conjunction with T-015-12. Also done in conjunction with R-114, R-043, R-100.
28	23560	23560	41756013	T-310-14, Line DFM-0141-01, Crockett	Crockett	ARB	6-May-13	19-May-13	$ 1,620,636.00	$ 697,691.00	$ 204,007.00	$ 17,156.00	$ 462,593.00	$ 13,935.00	$ (922,945.00)	$ 24,984.00	$ -	No	Accelerated from 2014 to 2013 due to Class 3 Location.
29	23483	23483	41859176	T-360-14, Line DFM-7226-13, Modesto	Modesto	Snelson	29-Apr-13	8-Jun-13	$ 1,972,730.00	$ 1,132,301.00	$ 194,355.00	$ 6,359.00	$ 920,795.00	$ 10,792.00	$ (840,429.00)	$ -	$ -	No	Accelerated from 2014 to 2013 to offset delays on other projects.
30	24183	25897	41482931	TIM-042-12, Line L-057A-MD1, McDonald Island	McDonald Island	ARB	14-Jan-13	15-Feb-13	$ 1,993,254.00	$ 1,423,331.00	$ 538,606.00	$ 66,449.00	$ 775,136.00	$ 43,140.00	$ (569,923.00)	$ 868,534.00	$ -	No	Delayed from 2012 to 2013 to aid in balancing the use of GC resources.

TABLE 11-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS COMPLETED
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Order Number	Project Description	City	Construction Contractor	Mobilization Date	Tie-in Date	Job Estimate Amount	Total Cost	Labor Cost	Materials Cost	Contracts Cost	Other Cost	Variance to Budget	PSEP Disallowed Cost	Non-PSEP costs	>10% Over Budget	Comments
31	24183	25896	41600051	TIM-043-12, Line L-057A-MD1, McDonald Island	McDonald Island	ARB	14-Jan-13	15-Feb-13	$ 1,809,361.00	$ 1,132,351.00	$ 281,403.00	$ 76,343.00	$ 752,953.00	$ 21,652.00	$ (677,010.00)	$ 1,132,349.00	$ -	No	Delayed from 2012 to 2013 to aid in balancing the use of GC resources.
32	23478	27652	41743429	TIM-273-13, Line DFM-7226-01, Modesto	Modesto	Snelson	29-Apr-13	8-Jun-13	$ 2,875,479.00	$ 2,724,385.00	$ 509,729.00	$ 44,618.00	$ 2,164,174.00	$ 5,864.00	$ (151,094.00)	$ 799,061.00	$ 318,575.00	No	
33	23749	27653	41743430	TIM-274-13, Line GCUST5900, Fremont	Fremont	Underground	4-Jun-13	15-Jun-13	$ 1,324,223.00	$ 577,972.00	$ 255,858.00	$ 6,078.00	$ 286,138.00	$ 29,898.00	$ (746,251.00)	$ -	$ 577,972.00	No	Added nitrogen test from filed TAPS-MI REPL (PSRS 23749) to accommodate a required Integrity Management assessment.
34	23600	23600	30842290	V-013 Valve Auto - Hamlin Court, 1V, Ph. 1	Sunnyvale	Snelson	24-Aug-12	1-Apr-13	$ 1,580,499.00	$ 1,104,834.00	$ 239,935.00	$ 210,888.00	$ 590,750.00	$ 63,261.00	$ (475,665.00)	$ -	$ -	No	Delayed from 2012 to 2013 due to difficulties in obtaining permits from the City of Sunnyvale for electrical service connections.
35	23601	23601	30842316	V-014 Valve Auto - Sand Hill, 2V, Ph. 1	Menlo Park	US Pipeline	8-Sep-12	16-Apr-13	$ 3,513,449.00	$ 4,217,839.00	$ 655,086.00	$ 621,149.00	$ 2,712,130.00	$ 229,474.00	$ 704,390.00	$ -	$ -	Yes	Delayed from 2012 to 2013 in order to coordinate with clearance for replacement project on the same Line, L-109.
36	23604	23604	30842319	V-017 Valve Auto - Sullivan Ave, 1V, Ph. 1	Daly City	ARB	18-Sep-12	6-Apr-13	$ 835,815.00	$ 626,518.00	$ 92,073.00	$ 43,563.00	$ 444,794.00	$ 46,088.00	$ (209,297.00)	$ -	$ -	No	Delayed from 2012 to 2013 due to clearance constraints and construction complexities.
37	23606	23606	30842303	V-019 Valve Auto - Martin Station, 4V, Ph. 1	Daly City	Snelson	6-Sep-12	25-Apr-13	$ 1,176,884.00	$ 775,071.00	$ 190,898.00	$ 15,850.00	$ 517,922.00	$ 50,401.00	$ (401,813.00)	$ -	$ -	No	Delayed from 2012 to 2013 due to clearance constraints and construction complexities.
38	23970	23970	30842289	V-028 Valve Auto - Half Moon Bay Tap, 2V, Ph. 1	San Mateo	US Pipeline	2-Nov-12	13-Feb-13	$ 893,119.00	$ 991,028.00	$ 325,018.00	$ 161,394.00	$ 393,456.00	$ 111,160.00	$ 97,909.00	$ -	$ -	Yes	Delayed from 2012 to 2013 due to clearance resource constraints.
39	24284	24284	30847366	V-032 Valve Auto - SP3-Line 191 Mtr Sta, 4V, Ph 1	Pittsburg	GT/GC	22-Jan-13	19-Mar-13	$ 431,091.00	$ 347,224.00	$ 273,424.00	$ 70,907.00	$ 471,716.00	$ (468,823.00)	$ (83,867.00)	$ -	$ -	No	
40	24288	24288	30847365	V-038 Valve Auto - San Pablo, 3V, Ph. 1	San Pablo	GT/GC	12-Mar-13	18-Apr-13	$ 1,103,042.00	$ 619,801.00	$ 212,591.00	$ 168,412.00	$ 341,574.00	$ (102,776.00)	$ (483,241.00)	$ -	$ -	No	
41	23649	23649	30842285	V-051 Valve Auto - Fairway Avenue, 2V, Ph. 1	San Leandro	GT/GC	27-Feb-13	28-Jun-13	$ 1,093,003.00	$ 824,159.00	$ 357,584.00	$ 126,558.00	$ 264,894.00	$ 75,123.00	$ (268,844.00)	$ -	$ -	No	

TABLE 12-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS BEGUN BUT CURRENTLY UNFINISHED
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
1	24009	24009	I-001 L-131 MP 50.5-57.4 UPGRADE PH-1	2/14/2013	9/28/2013	$ 5,786,394.00	Delayed from 2012 to 2013 due to workspace limitations at Milpitas Station and resource allocation to other higher priority PSEP work.
2	24023	24023	I-005 L-300A MP 299-352 UPGRADE PH-1	3/25/2013	7/20/2013	$ 12,223,488.00	
3	24017	24017	I-003 L-300B MP 299-351.8 UPGRADE PH-1	2/14/2013	9/23/2013	$ 11,916,445.00	
4	23694	23694	R-023 L-131_1 REPL 1.39MI MP 32.38-33.77 PH1	1/15/2013	7/31/2013	$ 15,724,794.00	Delayed from 2012 to 2013 as a result of schedule balancing and permits requiring long lead times.
5	23720	26014	R-003 DFM-7221-10 REPL 4.05mi MP 12.07-16.13 PH1	5/21/2013	7/27/2013	$ 16,945,787.00	Delayed from 2012 to 2013 due to construction difficulties.
6	23365	30791	R-192 L-109 REPL 0.03MI MP 9.87-9.89 Spread 6B	2/6/2014	3/12/2014		A portion of this original project was tied-in in 2012 (PSRS 23366) with this 149 feet to be completed in 2013 because a school could not take the outage required for clearance in 2012; however, it has now been delayed until 2014 to coincide with other work on the line so this portion has been split to a separate project and the other portion reported as complete. Job Estimate (JE) in progress.
7	23688	27979	R-134 L-114_2 REPL 3.60MI MP 12.70-16.52 PH1	1/14/2013	9/20/2013	$ 26,853,561.00	Delayed from 2012 to 2013 due to complicated installation methods which require an additional easement and to coordinate with other work in the City of Brentwood.
8	23845	27960	R-133 L-167 REPL 4.76MI MP 29.78-34.53 PH1	4/8/2013	7/27/2013	$ 24,333,996.00	
9	23698	26843	R-051 L-210A REPL 1.30mi MP 24.14-25.41 PH1	5/28/2013	8/30/2013	$ 7,090,982.00	Delayed from 2012 to 2013 in order to minimize revenue impacts to land owners.
10	23499	27622	T-240-13, Line L-162A, Tracy	6/7/2013	7/15/2013	$ 2,080,533.00	
11	24188	25870	T-028-12, Line DFM-2403-12, Fremont	5/6/2013	7/15/2013	$ 3,322,992.00	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012.
12	23524	28408	T-208B-13, Line L-187, Soledad	5/22/2013	7/26/2013		JE included with T-208A-13 (same PSRS/Order #) - 3 way split occurred post estimate. T-208B-13 is ~60% of original length and T-208A-13 tied-in in Q2.
13	23524	28408	T-208C-13, Line L-187, Soledad	5/22/2013	8/7/2013		JE included with T-208A-13 (same PSRS/Order #) - 3 way split occurred post estimate. T-208C-13 is ~11% of original length and T-208A-13 tied-in in Q2.
14	23550	27615	T-229C-13, Line L-118B, Madera	5/17/2013	7/8/2013		JE included with T-229A-13 - split occurred post estimate. T-229C-13 is ~89% of original length and T-229A-13 tied in Q2.
15	23506	27623	T-241-13, Line L-177B, Chico	5/30/2013	8/4/2013	$ 3,119,267.00	
16	23885	27645	T-265-13, Line DFM-1004-01, Orland	5/30/2013	7/20/2013	$ 2,520,018.00	Accelerated from 2014 to 2013 to offset delays on other projects.
17	23511	25860	TIM-022B-12, Line L-191-1, Walnut Creek	6/3/2013	8/12/2013	$ 4,650,684.00	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE includes TIM-022C-12 and TIM-022D-12- split occurred post estimate. TIM-022B-12 is ~61% of original length.
18	23511	25860	TIM-022C-12, Line L-191-1, Walnut Creek	6/3/2013	7/23/2013		Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE included under TIM-022D-12 (same PSRS/Order number) because split occurred post estimate. TIM-022C-12 is ~24% of original length.
19	23511	25860	TIM-022D-12, Line L-191-1, Walnut Creek	6/3/2013	7/23/2013		Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE included under TIM-022D-12 (same PSRS/Order number) because split occurred post estimate. TIM-022D-12 is ~15% of original length.
20	23602	23602	V-015 Valve Auto - Edgewood, 6V, Ph. 1	5/22/2013	11/19/2013	$ 4,731,789.00	Delayed from 2012 to 2013 due to clearance constraints and difficulty in obtaining required permits.
21	23597	23597	V-010 Valve Auto - Commercial Way, 3V, Ph. 1	4/17/2013	10/3/2013	$ 4,012,486.00	Delayed from 2012 to 2013 due to clearance constraints.
22	23647	23647	V-050 Valve Auto - Winton Avenue, 1V, Ph. 1	3/21/2013	7/11/2013	$ 934,216.00	
23	23645	23645	V-049 Valve Auto - Alvarado, 1V, Ph. 1	4/16/2013	7/10/2013	$ 1,186,817.00	
24	N/A	29461	V-083 Valve Auto - Helm Tap Station, 1V, Ph. 1	5/21/2013	9/4/2013	$ 499,534.00	New Valve Automation project combined with plane ILI project to increase cost effectiveness and support standardization.
25	24254	28282	V-031B Valve Auto Delta Fair, 1V, Ph. 1	5/15/2013	9/4/2013	$ -	Valve Automation site selected at Delta Fair (1 of 2) instead of Antioch Town Meter Station for constructability and cost reasons. JE in progress.

TABLE 12-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS BEGUN BUT CURRENTLY UNFINISHED
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
26	27893	27893	V-039A Valve Auto - Clayton Reg Station, 1V, Ph. 1	6/3/2013	8/30/2013	$ -	Valve Automation site selected at Clayton Regulator Station instead of Crystal Ranch for constructability and cost reasons. Delayed from 2012 to 2013 to allow time for engineering and planning at this new location. JE in progress.
27	23631	23631	V-040 Valve Auto - Walnut Ave, 1V, Ph. 1	6/3/2013	8/30/2013	$ -	JE in progress.
28	24212	27608	T-223A-13, Line L-050A-1, Marysville	5/6/2013	7/9/2013	$ 2,170,350.00	
29	23913	29511	T-333-14, Line DFM-1502-02, Marysville	5/6/2013	7/2/2013	$ 1,696,478.00	Accelerated from 2014 to 2013 to align clearance with T-223A-13 in 2013 and avoid a second shut down in 2014.
30	23911	23911	T-331A-14, Line DFM-1501-01, Yuba City	5/13/2013	7/10/2013	$ 3,033,154.00	Accelerated from 2014 to 2013 to offset delays on other projects. JE includes T-331B-14 (same PSRS/Order #) because split occurred post estimate. T-331A-14 is ~76% of original length.
31	23570	27603	T-217-13, Line DFM-0215-01, Belmont	6/14/2013	8/3/2013	$ 2,226,907.00	
32	23824	23824	R-137 L-173 REPL 0.01MI MP 5.50-7.63 PH1	6/24/2013	7/29/2013	$ 1,150,893.00	
33	23762	23762	R-038 DFM-1813-02 REPL 0.01MI MP 1.00-1.06 PH1	6/21/2013	7/6/2013	$ 569,083.00	Delayed from 2012 to 2013 to accommodate other higher priority projects in 2012. JE in progress.
34	23731	23731	R-102 L-162A REPL 1.12MI MP 6.62-7.72 PH1	6/13/2013	7/15/2013	$ 2,387,228.00	Accelerated from 2014 to 2013 due to meet Integrity Management requirements
35	24895	24895	R-110 DFM-3008-01 REPL 0.03mi MP 7.99-8.02 PH1 <<CM-0407 V-040>>	6/3/2013	8/30/2013		Project completed in conjunction with and included in JE for Valve Auto project Walnut Ave (PSRS 23631).
36	23532	27606	T-220-13, Line L-021B, Petaluma	6/19/2013	7/27/2013	$ 2,139,092.00	
37	23864	27569	T-174-12, Line DFM-1816-05, Watsonville	6/17/2013	7/31/2013	$ 2,513,651.00	Accelerated from 2014 to 2012 to facilitate pressure restoration on the line, subsequently delayed to 2013 as a result of material delivery delays and environmental permitting constraints (CA Tiger Salamander).
38	23550	27614	T-228-13, Line L-118B, Madera	6/14/2013	8/2/2013	$ 2,205,191.00	
39	23911	23911	T-331B-14, Line DFM-1501-01, Yuba City	5/13/2013	7/10/2013		Accelerated from 2014 to 2013 to offset delays on other projects. JE included with T-331A-14 (same PSRS/Order #) - split occurred post estimate. T-331B-14 is ~24% of original length
40	23524	28409	T-209-13, Line L-187, Soledad	6/20/2013	8/17/2013	$ 3,536,097.00	
41	23624	23624	V-035 Valve Auto - Vine Hill, 1V, Ph. 1	3/19/2013	7/2/2013	$ 1,640,938.00	
42	23622	23622	V-033 Valve Auto - Los Medanos, 3V, Ph. 1	4/13/2013	8/6/2013	$ -	JE in progress.
43	N/A	29463	V-084 Valve Auto - West Ford Ave, 1V, Ph. 1	6/14/2013	9/5/2013	$ 702,289.00	New Valve Automation project combined with plane ILI project to increase cost effectiveness and support standardization.
44	N/A	29637	V-087 Valve Auto - L-138 Adams Elm Mtr RegStn, 1V, Ph. 1	6/17/2013	8/19/2013	$ 694,886.00	New Valve Automation project combined with plane ILI project to increase cost effectiveness and support standardization.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
1	24025	24025	I-006 L-132 MP 31.96-38.39 UPGRADE PH-1	2-Aug-13	7-Oct-13	$ 2,750,137.00	Delayed from 2012 to 2013 to coordinate with Crystal Springs Valve Auto project which was rescheduled due to permitting delays for efficiency and cost effectiveness.
2	24898	29426	L-105N-3 TEST 0.03MI MP 0.00-0.01 PH1	TBD	TBD	$ -	Added as new nitrogen test project from filed replacement project for cost efficiency reasons (line runs under a railroad), subsequently delayed from 2013 to 2104 due to long lead permitting required from the railroad company. Job Estimate (JE) in progress.
3	23471	23471	L-131Z TEST 0.54MI MP 0.00-0.54 PH1	TBD	TBD	$ -	Delayed from 2013 to 2014 to coordinate with other work in the vicinity. JE in progress.
4	23800	23800	L-172A-17-3 REPL 0.01MI MP 0.00-0.00 PH1	TBD	TBD	$ -	Delayed from 2013 to 2014 to coordinate with other work on the same line. JE in progress.
5	23742	23742	L-314A REPL 0.08MI MP 0.15-0.24 PH1	TBD	TBD	$ -	Delayed from 2013 to 2014 to coordinate with other work on L-314 which is this vicinity. JE in progress.
6	24077	27594	R-007 L-108_1A REPL 2.24mi MP 37.14-38.17 PH1	24-Oct-13	10-Dec-13	$ -	Accelerated from 2014 to 2013 to incorporate adjacent segments identified as high priority upon completion of data validation. JE in progress.
7	23815	23815	R-010 L-108_2 REPL 0.14mi MP 48.16-48.20 PH1	12-Feb-14	21-Apr-14	$ -	Accelerated from 2014 to 2013 to coincide with other L-108 work in the area. JE in progress.
8	23743	26006	R-011 L-118A REPL 7.24MI MP 5.62-12.55 PH1	16-Jul-13	23-Oct-13	$ 12,570,508.00	
9	23790	27573	R-015 L-050A REPL 2.67mi MP 11.03-18.41 PH1	20-Jun-14	12-Aug-14	$ -	JE in progress.
10	24900	24900	R-016 L-108_3 REPL 2.47mi MP 63.49-65.96 PH1	15-Apr-14	6-Jun-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing.
11	23704	26516	R-031 L-109_3B_1 REPL 1.04 MI MP 18.61-19.71 PH1	TBD	29-Aug-14	$ -	JE in progress.
12	24899	24899	R-035 L-105N-5 REPL 0.10mi MP 36.39-36.47 PH1	26-Jun-14	5-Aug-14	$ -	Delayed from 2012 to 2014 due to schedule and resources load balancing in 2012, subsequently delayed due to potential move of Port of Oakland Pressure Limiting Station. JE in progress.
13	23926	29247	R-037 L-172A REPL 2.76MI MP 75.43-78.53 PH1	18-Jul-13	15-Oct-13	$ -	Added as new Replacement project as a result of data validation. JE in progress.
14	24254	24254	R-042 SP-3 REPL 0.01mi MP 174.29-174.29 (HWY4) PH1	25-Sep-14	5-Nov-14	$ -	Delayed from 2012 to 2014 initially to allow completion of engineering and constructability analysis after scope change (segment changes due to records verification in 2012), subsequently delayed further due to scheduling and workload balancing. JE in progress.
15	23692	26023	R-046 L-109_4A_1 REPL 2.25MI MP 24.84-27.26 PH1	12-Jun-14	11-Oct-14	$ -	JE in progress.
16	23692	26025	R-048 L-109_4C REPL 1.25 MI MP 30.52- 31.7601 PH1	6-Jun-14	18-Oct-14	$ -	JE in progress.
17	23704	27018	R-052 L-109_3C REPL 0.78 MI MP 23.3-24.00 PH1	TBD	19-Sep-14	$ -	JE in progress.
18	24059	26057	R-055 L-057A REPL 1.58MI MP 8.84-10.43 PH1	27-May-14	18-Sep-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
19	23867	26041	R-056 L-220 REPL 5.77MI MP 18.73-34.92 PH1	26-Jul-13	30-Nov-13	$ -	JE in progress.
20	24079	26053	R-057 L-124A REPL 4.61mi MP 20.63-26.27 PH1	3-Jun-14	23-Aug-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
21	23727	26010	R-058 L-021F REPL 2.16MI MP 0.00-2.15 PH1	12-Feb-14	18-Mar-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
22	23822	28468	R-059 L-123 REPL 3.80MI MP 0.00-9.74 PH1	20-Aug-13	2-Dec-13	$ -	Accelerated from 2014 to 2013 to accommodate a required Integrity Management assessment. JE in progress.
23	24052	26049	R-060 L-021D REPL 2.63MI MP 19.27-24.49 PH1	14-Mar-14	24-Apr-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing.
24	23702	27951	R-061 L-196A REPL 2.06MI MP 11.42-13.45 PH1	17-Jun-14	7-Oct-14	$ -	Delayed from 2013 to 2014 due to scheduling and workload balancing. JE in progress.
25	23811	23811	R-062 DFM-0603-01 REPL 0.58MI MP 0.00-0.57 PH1	13-Jul-13	2-Aug-13	$ -	JE in progress.
26	23780	29401	R-064 DFM-0604-16 REPL 0.18 MI MP 0.00-0.18 PH1	30-Aug-13	3-Oct-13	$ 895,352.00	
27	23791	23791	R-066 L-119B REPL 1.12MI MP 0.59-2.23 PH1	7-Feb-14	25-Mar-14	$ -	Delayed from 2013 to 2014 due to schedule and workload balancing. JE in progress.
28	23724	25719	R-067 L-109_2B REPL 0.18MI MP 2.82-10.15 PH1	29-Mar-14	19-Jun-14	$ -	JE in progress.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
29	23790	25790	R-069 L-050A TRANSFER 5.03mi MP 2.55-7.60 PH1	19-Jul-13	15-Oct-13	$ -	Added as new replacement/transfer project from filed test project as a result of data validation. JE in progress.
30	23688	26048	R-103 L-114_2 REPL 2.18MI MP 10.52-12.70 PH1	22-Jul-14	12-Nov-14	$ -	Delayed from 2012 to 2014 due to permits requiring long lead times. JE in progress.
31	23769	23769	R-105 DFM-1815-02 REPL 0.48MI MP 18.76-19.24 PH1	7-Sep-13	16-Oct-13	$ -	JE in progress.
32	24894	24894	R-113 DFM-3002-01 REPL 0.02mi MP 0.00-0.00 PH1	11-Dec-14	21-Jan-15	$ -	Delayed from 2013 to 2014 due to accommodate additional engineering (existing obstructions surrounding the line). JE in progress.
33	23802	23802	R-122 DFM-1306-01 REPL 0.01MI MP 1.48-4.19 PH1	31-Jul-13	9-Aug-13	$ 470,534.00	
34	24889	24889	R-124 DFM-1306-06 REPL 0.02MI MP 0.00-0.01 PH1	15-Jul-13	29-Jul-13	$ 415,359.00	
35	23470	27890	R-132 DFM-7222-01 REPL 10.08MI MP 0.99-11.16 PH1	18-Jul-13	17-Oct-13	$ -	Added as new replacement project from filed test project (PSRS 28511) and accelerated from 2014 to 2013 due to a necessary diameter increase on the line for a capacity increase. JE in progress.
36	23728	27902	R-135 L-103 REPL 0.15MI MP 25.31-25.46 PH1	28-Jan-14	8-Mar-14	$ -	New replacement project added on basis of construction efficiency (2 pipeline segments that remain after completion of records verification on prior filed strength test project) . JE in progress.
37	23743	28091	R-140 L-118A TRANSFER 6.03MI MP 0.00-5.62 PH1	11-Sep-13	28-Sep-13	$ -	Added new project for this transfer to distribution because a new line is being installed instead of L-111A and L-118A which run parallel. Both of these lines are transferred to distribution where they connect to the new line. JE in progress.
38	23470	28494	R-143 DFM-7222-01 REPL 0.61MI MP 0.00-0.61 PH1	8-Apr-14	20-May-14	$ -	Added as new replacement project from filed test project (PSRS 28511) due to a necessary diameter increase on the line for a capacity increase. JE in progress.
39	23533	28472	R-144 L-021C REPL 0.90 MI MP 50.51 - 51.41 PH1	15-Aug-13	29-Sep-13	$ -	Added as new replacement project from filed test project for cost efficiency reason to avoid the need for large amounts of Liquefied Natural Gas (LNG) for customer support during a test. JE in progress.
40	23529	29053	R-145 L-306 REPL 0.01MI MP 43.30-43.31 PH1	10-Feb-14	24-Mar-14	$ -	Added as short replacement project for cost efficiency reasons because all except these 50 ft. of filed test was removed from PH1 due to records verified, subsequently delayed from 2013 to 2014 due to schedule and workload balancing. JE in progress.
41	23682	23682	R-148 DFM-1617-01 REPL 0.45 MI MP 0.00-1.26 PH1	25-Sep-13	9-Nov-13	$ -	Accelerated from 2014 to 2013 to address required Integrity Management assessments.
42	24553	29067	R-149 L-153 REPL 0.06MI MP 3.45-3.51 PH1	1-Oct-14	11-Nov-14	$ -	Added as a new replacement project from a filed test project for cost efficiency reasons) - test project cancelled as a result of data validation. JE in progress.
43	23780	29425	R-152 DFM-0604-16 REPL 0.32 MI MP 0.18-0.50 PH1	7-Sep-13	10-Oct-13	$ -	JE in progress.
44	23796	29633	R-153 L-021C REPL 0.22MI MP 34.85-35.04 PH1	11-Feb-14	18-Mar-14	$ -	JE in progress.
45	24272	29275	R-157 DFM 1603-01 REPL 1.23MI MP 0.07-1.30 PH1	23-Aug-13	21-Sep-13	$ -	Added as new replacement project from filed test project after most of test was removed due to records verified. Downgrading to distribution pressure because a new 10" transmission line will be run parallel. JE in progress.
46	24052	29743	R-158 L-021D REPL 0.62MI MP 18.64-19.27 PH1	1-Feb-14	18-Apr-14	$ -	Delayed from 2013 to 2014 due to permits requiring long lead times and land acquisition challenges. JE in progress.
47	23918	29868	R-160 DFM-1301-01 REPL 4.18MI MP 0.00-4.18 PH1	4-Mar-14	17-May-14	$ -	Added as new replacement project from filed test project for cost efficiency reasons after data validation was completed - certain segments being downgraded to Distribution. JE in progress.
48	23877	29869	R-161 DFM 1815-02 REPL 6.47 MI MP 6.50-16.85 PH1	1-Apr-14	29-Apr-14	$ -	Added as new replacement project from filed test project after most of test was cancelled due to records verified.
49	23733	23733	R-164 DFM-1603-03 REPL 0.49MI MP 0.004-0.49 PH1	9-Oct-13	5-Nov-13	$ -	JE in progress.
50	23704	30361	R-165 L-109_3AA REPL 0.10MI MP 17.01-17.11 PH1	11-Aug-14	22-Sep-14	$ -	Delayed from 2012 to 2014 due to permits requiring long lead times. JE in progress.
51	23704	30589	R-166 L-109_3B_2 REPL 1.75 MI MP 20.38-22.20 PH1	5-Mar-14	31-May-14	$ -	JE in progress.
52	23822	30616	R-167 L-123 REPL 1.92MI MP 4.18-13.74 PH1	9-May-14	16-Aug-14	$ -	JE in progress.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
53	23692	30667	R-185 L-109_4A_2 REPL 1.59 MI MP 28.60-30.11	2-Aug-14	29-Dec-14	$ -	JE in progress.
54	24890	27904	R-202 DFM-1607-01 REPL 0.99MI MP 0.63-1.62 PH1	9-Jul-13	25-Sep-13	$ -	Accelerated from 2014 to 2013 to accommodate a planned diameter increase from 8" to 12" to increase system capacity. JE in progress.
55	23796	29631	R-205 L-021C REPL 0.54MI MP 31.85-32.39 PH1	23-Jan-14	17-Apr-14	$ -	Accelerated from 2014 to 2013 to address required Integrity Management assessments. JE in progress.
56	24055	24055	R-206 L-021H REPL 0.61MI MP 0.00-6.42 PH1	10-Feb-14	15-Mar-14	$ -	JE in progress.
57	23789	23789	R-207 L-177A REPL 0.01MI MP 25.54-173.89 PH1	11-Apr-14	23-May-14	$ -	JE in progress.
58	23728	29124	R-230 L-103 REPL 0.01MI MP 22.20-22.21 PH1	28-Feb-14	24-Apr-14	$ -	JE in progress.
59	23505	30025	T-013C-12, Line L-109, Daly City	26-Jul-13	29-Aug-13	$ -	Delayed from 2012 to 2013 due to permitting delays with Caltrans. JE in progress.
60	23874	25847	T-016-12, Line L-131_2, Fremont	14-Aug-13	18-Sep-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
61	23511	25861	T-023-12, Line L-191-1, Martinez	8-Jul-13	27-Aug-13	$ 2,382,051.00	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012.
62	23856	25889	T-038-12, Line DFM-1615-01, Modesto	1-Jul-13	22-Aug-13	$ 4,154,073.00	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012.
63	23856	25891	T-039A-12, Line DFM-1615-01, Modesto	10-Jul-13	9-Sep-13	$ 2,704,533.00	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012.
64	23493	25820	T-051A-12, Line L-142N, Bakersfield	1-Jul-13	5-Aug-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
65	23493	25820	T-051B-12, Line L-142N, Bakersfield	1-Jul-13	5-Aug-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
66	23493	25820	T-051C-12, Line L-142N, Bakersfield	1-Jul-13	19-Aug-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
67	23493	25820	T-051D-12, Line L-142N, Bakersfield	1-Jul-13	30-Aug-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
68	23493	25820	T-051E-12, Line L-142N, Bakersfield	1-Jul-13	13-Sep-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
69	23554	25864	T-081-12, Line L-119B, North Highlands	13-Aug-13	2-Oct-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
70	23524	28410	T-210-13, Line L-187, Gonzales	10-Jul-13	30-Aug-13	$ -	JE in progress.
71	23542	28411	T-211A-13, Line L-187, Chualar	8-Aug-13	14-Sep-13	$ -	JE in progress.
72	23542	28411	T-211B-13, Line L-187, Chualar	8-Aug-13	14-Sep-13	$ -	JE in progress.
73	23569	27611	T-225-13, Line DFM-0604-07, Vacaville	23-Aug-13	25-Oct-13	$ -	JE in progress.
74	23892	29093	T-227-13, Line DFM-1023-01, Redding	12-Jul-13	16-Aug-13	$ -	JE in progress.
75	23550	27617	T-230-13, Line L-118B, Madera	25-Jul-13	5-Sep-13	$ -	JE in progress.
76	23499	27621	T-239-13, Line L-162A, Tracy	15-Jul-13	19-Aug-13	$ -	JE in progress.
77	23872	27632	T-268-13, Line DFM-1813-02, Seaside	1-Jul-13	24-Jul-13	$ 2,175,967.00	
78	23872	27649	T-269A-13, Line DFM-1813-02, Monterey	1-Jul-13	24-Jul-13	$ 3,216,887.00	JE includes T-269B-13 (same PSRS/Order #). T-269A-13 is ~37% of original length.
79	23872	27649	T-269B-13, Line DFM-1813-02, Monterey	1-Jul-13	24-Jul-13		JE included with T-269A-13 (same PSRS/Order #). T-208B-13 is ~63% of original length.
80	23472	27651	T-272A-13, Line DFM-7223-01, Turlock	12-Aug-13	25-Sep-13	$ -	JE in progress.
81	23472	27651	T-272B-13, Line DFM-7223-01, Turlock	12-Aug-13	25-Sep-13	$ -	JE in progress.
82	23748	28495	T-281B-13, Line L-191, Antioch	3-Sep-13	24-Oct-13	$ -	Added new test project from filed replacement project as a result of data validation. JE in progress.
83	23926	30056	T-282A-13, Line L-172A, West Sacramento	26-Aug-13	10-Oct-13	$ -	Added as a new Test, some segments from Replacement and some new to PSEP - initially proposed replacement project could not be completed due to site conditions limiting constructability. JE in progress.
84	24906	30056	T-282B-13, Line L-172A-1, West Sacramento	26-Aug-13	10-Oct-13	$ -	Added as a new Test, some segments from Replacement and some new to PSEP, initially proposed Replacement could not be completed due to site conditions limiting constructability. JE in progress.
85	23769	30531	T-284-13, Line DFM-1815-02, Monterey	29-Aug-13	27-Sep-13	$ -	JE in progress.

TABLE 13-1
PACIFIC GAS AND ELECTRIC COMPANY
PROJECT STATUS SUMMARY - PROJECTS FORECASTED FOR PHASE 1 BUT YET TO START
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Mobilization Date	Tie-in Date	Job Estimate Amount	Comments
86	23690	27760	T-285-13, Line X6526, Kettleman City	1-Jul-13	24-Aug-13	$ -	Added as a new test project from filed TAP Replacement project and accelerated from 2014 to 2013 to coordinate with other work in the vicinity. JE in progress.
87	23567	23567	T-318-14, Line DFM-0604-06, Vacaville	24-Jul-13	17-Sep-13	$ -	Accelerated from 2014 to 2013 to offset delays on other projects. JE in progress.
88	23533	25833	TIM-065-12, Line L-021C, Penngrove	12-Aug-13	17-Sep-13	$ -	Delayed from 2012 to 2013 to accommodate other higher priority tests for Integrity Management in 2012. JE in progress.
89	23872	27648	TIM-267-13, Line DFM-1813-02, Marina	2-Aug-13	26-Aug-13	$ -	JE in progress.
90	23599	23599	V-012 Valve Auto - Lomita Park, 1V, Ph. 1	1-Apr-14	18-Aug-14	$ -	Delayed from 2012 to 2013 as a result of environmental/species issues. This valve is in a marsh in San Francisco where numerous protected species are present. JE in progress.
91	23603	23603	V-016 Valve Auto - Crystal Springs, 4V, Ph. 1	11-Jul-13	4-Nov-13	$ 4,317,996.00	Delayed from 2012 to 2013 due to permitting delays.
92	24281	30014	V-030 Valve Auto - Antioch Terminal, 5V, Ph. 1	15-Jul-13	19-Oct-13	$ -	JE in progress.
93	27532	27532	V-031A Valve Auto - California, 1V, Ph. 1	1-Aug-13	15-Nov-13	$ -	Valve Automation site selected at California Ave. (1 of 2) will be automated instead of Antioch Town Meter Station for constructability and cost reasons. JE in progress.
94	23623	23623	V-034 Valve Auto - Concord Meter Station, 1V, Ph. 1	22-Jul-13	12-Sep-13	$ 1,438,881.00	
95	23972	23972	V-044 Valve Auto - Sheridan Rd, 2V, Ph. 1	19-May-14	23-Jul-14	$ -	JE in progress.
96	23635	23635	V-045 Valve Auto - Livermore & Airway, 3V, Ph. 1	3-Aug-13	9-Sep-13	$ -	JE in progress.
97	23636	23636	V-046 Valve Auto - Dalton Crossover, 2V, Ph. 1	3-May-14	11-Sep-14	$ -	Delayed from 2013 to 2014 in order to coordinate with Non-PSEP ILI Retrofit project (PSRS 24224) at Dalton Crossover for construction efficiency reasons. JE in progress.
98	23637	23637	V-047 Valve Auto - Livermore Junction, 1V, Ph. 1	21-Aug-13	10-Oct-13	$ -	JE in progress.
99	23651	23651	V-052 Valve Auto - 51St Avenue, 1V, Ph. 1	24-Jul-13	30-Sep-13	$ -	JE in progress.
100	23655	23655	V-053 Valve Auto - 4th & Jefferson, 1V, Ph. 1	26-Jul-13	26-Sep-13	$ -	JE in progress.
101	23657	23657	V-054 Valve Auto - Brentwood Terminal, 9V, Ph. 1	15-Jul-13	14-Nov-14	$ -	Added new replacement for construction efficiency reasons (2 segments that remain after completion of records validation on filed strength test project). JE in progress.
102	23661	23661	V-056 Valve Auto - Bixler Rd, 1V, Ph. 1	11-Jan-14	19-Apr-14	$ -	JE in progress.
103	23663	23663	V-057 Valve Auto - Palm Tract, 2V, Ph. 1	22-Jul-13	23-Aug-13	$ 469,761.00	
104	23674	23674	V-063 Valve Auto - Valero Refinery Tap, 3V, Ph. 1	15-Jul-13	27-Sep-13	$ 1,829,215.00	Accelerated from 2014 to 2013 to offset delays on other projects.
105	23668	23668	V-066 Valve Auto - Cordelia, 6V, Ph. 1	15-Feb-14	17-Jul-14	$ -	JE in progress.
106	23667	23667	V-067 Valve Auto - Ripon-Modesto, 3V, Ph. 1	20-Feb-14	8-May-14	$ -	Accelerated from 2014 to 2013 to offset delays on other projects. JE in progress.
107	N/A	30094	V-068A Valve Auto - Airport & Louise, 3V, Ph. 1	11-Sep-13	24-Dec-13	$ -	Added to replace filed Valve Auto project Airport & Yosemite (PSRS 23664) for cost and efficiency reasons due to construction complexities at the filed project site. JE in progress.
108	23662	23662	V-069 Valve Auto - Airport & French Camp, 3V, Ph. 1	27-Aug-13	30-Sep-13	$ -	Accelerated from 2014 to 2013 to offset delays on other projects. JE in progress.
109	23660	23660	V-070 Valve Auto - Airport & Sorona, 3V, Ph. 1	15-Jul-13	28-Aug-13	$ -	Accelerated from 2014 to 2013 to offset delays on other projects. JE in progress.
110	23658	23658	V-071 Valve Auto - West Lane & Hammertown, 3V, Ph. 1	27-Sep-13	6-Nov-13	$ -	Accelerated from 2013 to 2012 to offset delays on other projects. JE in progress.
111	23656	23656	V-072 Valve Auto - 8 Mile Pls, 2V, Ph. 1	3-Aug-13	14-Sep-13	$ -	Accelerated from 2014 to 2013 to offset delays on other projects. JE in progress.
112	24023	29634	V-085 Valve Auto - L-300A MLV 328.06, 1V, Ph. 1	13-Aug-13	21-Nov-13	$ -	Added as a new Valve Automation project from what was originally part of the scope of ILI work because it will be more cost effective and allow for standardization of Valve Automation. JE in progress.
113	24017	29635	V-086 Valve Auto - L-300B MLV 327.83, 1V, Ph. 1	12-Oct-13	23-Nov-13	$ -	Added as a new Valve Automation project from what was originally part of the scope of ILI work because it will be more cost effective and allow for standardization of Valve Automation. JE in progress.
114	23632	23632	VALVE AUTO - FOLEY'S RANCH CROSSOVER, PH. 1	TBD	TBD	$ -	Delayed from 2013 to 2014 to coordinate work with the station rebuild at Foley's Ranch. JE in progress.
115	23638	23638	VALVE AUTO - THORTON AVE, PH. 1	TBD	TBD	$ -	Delayed from 2013 to 2014 to allow more time for engineering around construction complexities due to location within the vicinity of I-880. JE in progress.

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Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
1	24903	R-139 L-131Y REPL 0.01MI MP 0.53-0.54 PH1	North	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$60,000	1	No	There was an approximately one day delay starting clearance which increased project costs.
2	24903	R-139 L-131Y REPL 0.01MI MP 0.53-0.54 PH1	North	Changes After Issue for Bid (IFB)	Any changes to the project that were excluded from or occurred after IFB.	$25,000	5	No	There was an existing valve vault that we planned to tie-in to, but the new pipe could not be simply fed through the vault requiring a cut to be made to the vault resulting in additional work and subsequently additional costs.
3	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$25,000	2	Yes	An electrical pole was too close to the excavation so SMUD (Sacramento Municipal Utility District) was called to re-locate the pole.
4	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$10,000	N/A	Yes	Clearance on this project was delayed by approximately 4 hours which resulted in additional costs related to the additional time for the clearance crew and stand-by time for the construction crew. Multiple jobs were tie-ing in around the same time so schedule adjustments were required to accommodate system demands.
5	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Field Conditions Differ From Expected Conditions	As-built drawings and/or Geographic Information System (GIS) but did not match what was actually encountered in the field.	$5,000	N/A	Yes	An existing 2" pipe was found to be imbedded in concrete which required additional work to access.
6	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$60,000	N/A	Yes	A portion of pipe, a stub, was encountered that required replacement which resulted in additional project costs.
7	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$8,000	N/A	Yes	Two active valves were encountered that required deactivation.
8	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	North	Low Estimate	Specific cost assumptions in the Job Estimate proved to be inaccurate.	$20,000	N/A	Yes	Traffic Control and Labor costs in particular were underestimated.
9	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Dewatering	A high water table is encountered resulting in unplanned dewatering costs and delays in construction.	N/A	6	Yes	A delay was experienced while creating a discharge plan for the city.
10	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Cultural Resource Impacts	Discovery of Native American artifacts at the construction site may delay construction and result in increased project cost.	$100,000	6	Yes	A portion of this project was strength tested in 2012 to meet integrity management assessment deadlines - this allowed more time to complete the remaining replacement work in areas where several cultural artifacts has been encountered. Before resuming construction in 2013, the site was excavated to a depth of 2 feet where archeologists inspected then cleared the area.
11	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Mercury Cleaning - Pipe Replacement	Cleaning Mercury (Hg) from piping associated with asset retirement.	$60,000	N/A	Yes	Additional cleaning runs were required.
12	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$30,000	N/A	Yes	It was necessary to replace some valve boxes with broken lids.
13	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$20,000	N/A	Yes	A leaking valve was encountered and replaced.
14	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	Ctr Cst	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	N/A	6	Yes	Clearance commencement was delayed due to a delay in writing clearance and tie-in procedures - new changes to this process were being implemented to incorporate Contractor Alliance resources.
15	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Land Acquisition	Difficulty acquiring land due to a variety of complications (e.g. resistant land owners) that could result in schedule delays or increased cost (e.g. purchase land via eminent domain).	$500,000	12	No	Additional costs were incurred to negotiate easements with property owners. Additional contract land agents were hired to maximize property owner reach. Also there was an issue with the Railroad in middle of project path and delays in acquiring the needed easement led to additional mobilization costs to keep construction moving.
16	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$500,000	N/A	No	Some design changes were necessary, primarily due to a conflict with a new water line planned by the city. This incurred additional costs for re-engineering around the planned location of the new line. Additionally, the work was changed from a bore to Horizontal Directional Drilling (HDD) which also required additional engineering.
17	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$500,000	N/A	No	Additional materials were required for the Fresno Junction Regulator Station resulting from design adjustments after commencement of construction.

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18	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$700,000	12	No	Productivity was impacted by the additional time required for re-engineering resulting from the design change - bore to an HDD to address conflict with future city water main installation, cost to expedite materials, and cleaning/removal of an unforeseen abandoned PG&E gas line.
19	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Construction Trades Labor Cost Increase	Increases in construction costs resulting from a 2013 UA labor increase.	$200,000	N/A	No	There was a pay increase for welder/fitters/helpers due to a new 2013 labor agreement.
20	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$500,000	12	No	An additional tie-in was necessary to support the completion of a required Integrity Management assessment prior to the deadline in December 2012.
21	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$200,000	4	No	Additional E&I station work necessary at Fresno Junction and Fresno Load Center.
22	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Weather Impacts	Potential construction delays and resulting additional costs due to rain days. Potential rain interaction with species (e.g. CTS breading migration) delaying construction and increasing cost.	N/A	2	Yes	Two days of delay occurred as a result of rain.
23	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$600,000	N/A	Yes	A higher rate of productivity was assumed when planning than was achievable as a result of limited work space and other conditions. This resulted in additional construction management and QA/QC inspection costs for the additional construction duration.
24	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$150,000	N/A	Yes	Obstructions were encountered during excavation resulting in additional costs.
25	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Environmental/Species Impacts	Potential delays in construction due to the presence of protected or endangered species at the construction site.	$100,000	N/A	Yes	Higher monitoring costs that expected - it was know that burrowing owls could be present near the construction site.
26	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$120,000	N/A	Yes	Additional city inspection fees related to permits were incurred as a result of the extended schedule.
27	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Mercury Cleaning - Pipe Replacement	Cleaning Hg from piping associated with asset retirement.	$200,000	N/A	Yes	Mercury was identified as being present in the line so cleaning was required.
28	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Low Estimate	Specific cost assumptions in the Job Estimate proved to be inaccurate.	$800,000	N/A	Yes	The JE was created prior to this project split into three portions for constructability reasons and was then allocated to each project based on mileage. However, this method of allocation did not take into account the two additional mobilization/de-mobilization costs, site restoration costs and other site specific conditions that varied along the line resulting in a lower JE than would have otherwise been created. For the other two projects from the split that are planned for 2013, new JEs will be created.
29	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Unstable/Weak Soil	Unstable soils may require additional shoring which may cause delays to obtain and install.	)0 claim - pending neg	N/A	Yes	A tardy claim was submitted two months post tie-in claiming that soil conditions were different than anticipated. A claim team has been assembled and is evaluating and negotiating this claim.
30	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$450,000	N/A	Yes	Because tie-in was delayed until winter, LNG was required to guarantee uninterrupted service to customers and site restoration ($50,000) was required at the LNG site.
31	26442	R-100 L-131 RETIRE 0.37MI MP 8.56-8.93 PH1	Bay	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$67,000	N/A	No	A drip was located outside of the terminal, but was expected to be inside so the excavation was extended and deepened and the drip cut off, resulting in cost increases.
32	26442	R-100 L-131 RETIRE 0.37MI MP 8.56-8.93 PH1	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$152,000	N/A	No	An additional valve removal and pipe cap were required resulting in increased costs.
33	24909	R-043 SP4Z RETIRE 0.22mi MP 8.18-8.43 PH1	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$37,000	N/A	Yes	An excavation was added to cap off a tap from the main line resulting in additional costs.
34	24909	R-043 SP4Z RETIRE 0.22mi MP 8.18-8.43 PH1	Bay	Field Conditions Differ From Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$28,000	N/A	Yes	It was necessary to extend and deepen an excavation due to a complicated pipeline configuration.
35	25791	R-114 L-114 RETIRE 0.83 MP 8.18-8.92 PH1	Bay	Mercury Cleaning - Pipe Replacement	Cleaning Hg from piping associated with asset retirement.	$100,000	6	Yes	Additional cleaning runs were required.
36	25791	R-114 L-114 RETIRE 0.83 MP 8.18-8.92 PH1	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$92,000	N/A	Yes	Additional valve removals related to the retirement of the line were required resulting in cost increases.

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37	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$600,000	18	No	An additional tie-in was necessary in November due to the re-classification reduction in MAOP on a pipeline segment upstream of Adams and Elm station. Extra tie-in allowed lifting of Conditional Reduced Operating Pressure (CROP) to restore to full Maximum Allowable Operating Pressure (MAOP) to support Fresno winter loads.
38	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$1,550,000	24	No	Productivity issues were experienced due to delays in material delivery.
39	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Permitting	Unplanned permitting conditions, requirements and delays from various permitting agencies (e.g. limited working hours, limited access, delays in issuance, etc.).	$400,000	24	No	Permits with long lead times caused delays to the construction schedule.
40	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$860,000	24	No	Additional work was required at the regulator station at Adams and Elm.
41	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$1,285,000	132	No	A leaking 24" Main Line Valve (MLV) requiring replacement was encountered and resulted in delayed completion of tie-ins and removals of by-passes. (Break-out: $860K removal of bypasses and complete tie-ins after aborting original tie-in efforts on 1/31/13; $400K replacement of leaking MLV at Adams and Elm; $25K dig-up valve to determine cause and support subsequent removal).
42	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Construction Trades Labor Cost Increase	Increases in construction costs resulting from a 2013 UA labor increase.	$200,000	N/A	No	There was a pay increase for welder/fitters/helpers due to a new 2013 labor agreement.
43	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Unstable/Weak Soil	Unstable soils may require additional shoring which may cause delays to obtain and install.	$30,000	N/A	No	Bad soils/sugar sand were encountered requiring additional work and resources to handle.
44	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	Ctr Vly	Field Conditions Differ From Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$170,000	N/A	No	Other miscellaneous changes to project scope occurred due to differing field conditions (extended bore lengths, etc.).
45	25897	TIM-042-12, Line L-057A-MD1, McDonald Island	Ctr Vly	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$63,000	N/A	No	
46	25897	TIM-042-12, Line L-057A-MD1, McDonald Island	Ctr Vly	Construction Trades Labor Cost Increase	Increases in construction costs resulting from a 2013 UA labor increase.	$62,000	N/A	No	
47	24909	TIM-043-12, Line L-057A-MD1, McDonald Island	Ctr Vly	Construction Trades Labor Cost Increase	Increases in construction costs resulting from a 2013 UA labor increase.	$65,000	N/A	Yes	
48	28395	T-206-13, Line L-187, King City	Ctr Cst	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$450,000	14	No	Due to the age and shallow depth of the pipe as a result of years of farm work in the area, a risk was identified and later realized of the line being damaged from farming equipment. A leak was detected while the line was filled with water and under test pressure at which time various methods of locating the leak were deployed. The leak was located on day 7 by cutting the pipe at the halfway point, running a camera through one side while the other was capped and re-pressurized with water. The damaged section of pipe was replaced and the test completed successfully.
49	28395	T-206-13, Line L-187, King City	Ctr Cst	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$5,000	N/A	No	One customer lost gas service which was restored via a Compressed Natural Gas (CNG) tank.
50	23560	T-310-14, Line DFM-0141-01, Crockett	Bay	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$27,000	N/A	No	During excavation, 2 locations of corroded pipe were discovered, including an 8" 90 degree elbow, which required replacement resulting in cost increases.
51	23560	T-310-14, Line DFM-0141-01, Crockett	Bay	Dewatering	A high water table is encountered resulting in unplanned dewatering costs and delays in construction.	$5,000	N/A	No	Ground water was encountered inside the vaults which required pumping out resulting in additional costs.
52	23560	T-310-14, Line DFM-0141-01, Crockett	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$29,000	N/A	No	Additional sniff holes, an expanded excavation and sav-a-valves were necessary for project completion.
53	23560	T-310-14, Line DFM-0141-01, Crockett	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	impact under negotia	N/A	No	The construction crew worked unplanned overtime which may result in increases to the project cost.
54	27604	T-218-13, Line L-021B, Napa	Bay	Pigging	Potential issues may occur while pigging the line that cause delays or cost increases to resolve them.	$9,000	N/A	No	There were issues during pigging because the PIGs became stuck at a reducer so additional work and time was required to free them which resulted in cost increases.
55	27604	T-218-13, Line L-021B, Napa	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$30,000	N/A	No	Four new 12" mainline valves were installed and valve supports for these were added to the plans after IFB so this resulted in additional costs.

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56	27604	T-218-13, Line L-021B, Napa	Bay	Environmental/Species Impacts	Potential delays in construction due to the presence of protected or endangered species at the construction site.	$60,000	N/A	No	Additional flaggers for traffic control were added for safety reasons after the staging area was re-located to avoid a nesting bird which resulted in additional costs.
57	25841	T-015-12, Line L-131_2, Oakley	Bay	Support for Other Work Teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$28,000	N/A	No	Equipment and labor assistance (welding and other) were provided during clearance and tie-in. A fence was also removed to make clearance possible.
58	28245	T-279-13, Line SP4Z, Antioch	Bay	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$260,000	N/A	No	It was necessary to dig up a drip at the end of line SP4Z in the terminal. It was unknown how large the excavation would need to be and we needed to hydrotest the drip. The construction crew was aware that this dig and test were required and that the extent was unknown. There was also a note in the bid sheet that the excavation would likely need to be larger than planned which it was.
59	25884	T-093-12, Line L-210C, Vallejo	Bay	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$184,000	N/A	No	It was planned to replace a 26 ft portion of pipe, but when digging occurred to do so, after mark and locate, the excavation did not expose the correct portion of pipe due to as-built inaccuracy.
60	25884	T-093-12, Line L-210C, Vallejo	Bay	Support for Other Work Teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$17,000	N/A	No	G.C. was not available to complete planned tie-in so the contractor competed the work instead.
61	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$50,000	N/A	No	It was necessary to remove some unsatisfactory pipe resulting in project cost increases.
62	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Site Security Impacts	The project is located in an area that is known or discovered to have security concerns around theft, etc. so additional measures may be necessary to secure the site.	$18,000	N/A	No	The site location is known to have security concerns. For example, a valve project in this area experienced an issue last year where a drunk driver drove past the traffic control and into the site. Police presence was deemed necessary and added to project costs.
63	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$75,000	4	No	A valve broke during tie-in and had to be replaced.
64	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$38,000	N/A	No	An excavation was expanded and pipe modified at two locations.
65	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Support for Other Work Teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$75,000	N/A	No	Support was provided to the CNG group in the form of manpower and equipment.
66	27613	T-226-13, Line DFM-0817-01, San Jose	Ctr Cst	Support for Other Work Teams	Unplanned support (equipment or labor) was provided to other teams such as GC, CNG, or LNG because they did not have sufficient resources available at the time that they were needed.	$4,200	N/A	No	Additional compressors were required by the G.C. group during clearance and tie-in.
67	27653	TIM-274-13, Line GCUST5900, Fremont	Ctr Cst	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$50,000	N/A	No	Overtime was necessary to meet significantly tightened clearance window after a critical customer could not take the originally planned 5-day outage.
68	27609	T-224A-13, Line DFM-0604-01, Vacaville	North	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$30,000	1	No	An undocumented water line was encountered so the size of the bell hole was reduced in order to avoid affecting the water line pipe.
69	27609	T-224A-13, Line DFM-0604-01, Vacaville	North	Field Conditions Differ From Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$40,000	N/A	No	Two pipes were found to have concrete caps so it was necessary to perform the clearance first ahead of completing the excavation in order to safely remove the caps.
70	27609	T-224A-13, Line DFM-0604-01, Vacaville	North	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$30,000	N/A	No	As a result of the clearance necessary to remove the concrete caps, we were able to test an additional 130 feet of 4" line, saving us from having to do a separate project to test this section next year.
71	27652	TIM-273-13, Line DFM-7226-01, Modesto	Ctr Vly	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$150,000	3	No	Existing pipe to pipe contact (installed in the late 50s/early 60s) was encountered at a regulator station which required additional engineering and work to correct/adjust.
72	27652	TIM-273-13, Line DFM-7226-01, Modesto	Ctr Vly	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$50,000	N/A	No	A pressure control fitting was not located where it was expected so an additional excavation was required.

TABLE 19-1
PACIFIC GAS AND ELECTRIC COMPANY
COST IMPACTS BY PROJECT
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
73	27652	TIM-273-13, Line DFM-7226-01, Modesto	Ctr Vly	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$150,000	1	No	An excavation was extended at location B to fit the pipe as a result of encountering other unexpected utilities which increased project costs.
74	27652	TIM-273-13, Line DFM-7226-01, Modesto	Ctr Vly	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$50,000	N/A	No	Unexpected utilities were encountered so the construction crew was unable to relocate valves as planned which resulted in cost increases because attempts were made to do so prior to encountering the other utilities.
75	23483	T-360-14, Line DFM-7226-13, Modesto	Ctr Vly	Contaminated Soil	Contaminated soil found on a site during excavation. Potential costs associated with contaminated soil handling, storage, hauling and disposal.	$175,000	N/A	No	The State gave notification the day before mobilization that there is PCB (Poly Chloride Benzene) present in the soil which will result in cost increases to properly handle and dispose of soil.
76	23483	T-360-14, Line DFM-7226-13, Modesto	Ctr Vly	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$50,000	N/A	No	It was planned to move a bridle set out of the roadway, but during excavation other utilities were encountered so it would not be possible to move it and additional engineering was required to adjust accordingly.
77	23483	T-360-14, Line DFM-7226-13, Modesto	Ctr Vly	Hydrostatic Test Rupture/Leak	Potential rupture or leak during a hydrostatic test results in increased cost.	$150,000	6	No	A leak was discovered when preparing to test so a leak tracer was introduced into the line during filling operations. Visual inspection occurred and soil samples were tested from above the pipe to test for the leak tracer gas. The line was also probed which located the leak. A Current Tracer was also used which detects where coating loss has occurred since it should be where the leak is located which also was successful in locating the leak.
78	28408	T-208A-13, Line L-187, Soledad	Ctr Cst	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$100,000	N/A	No	Cross compression was required during this test. In order to mitigate the risk in the event that a pressure drop occurred or the compressor failed during cross compression, an additional compressor was on site as back up to ensure customer support.
79	27615	T-229A-13, Line L-118B, Madera	Ctr Vly	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$200,000	4	No	T-229A-13 was split into T-229A-13 and T-229C-13 portions to ensure ongoing supply to a customer tap requiring 400 mcf per day - sufficient LNG resources were not readily available - bypass engineering resulted in cost increases and a few days schedule delay to each portion.
80	25866	T-082-12, Line L-119B, Sacramento	North	Field Conditions Differ from Expected Conditions	As-built drawings and/or GIS but did not match what was actually encountered in the field.	$118,000	5	No	
81	25902	T-046-12, Line L-138, Fresno	Ctr Vly	Unexpected Condition of Pipe, Valves or Fittings	Pipe, valves or fittings may be leaking or require additional work to repair or replace them, not including linear indications on the pipe.	$72,000	6	No	
82	25902	T-046-12, Line L-138, Fresno	Ctr Vly	Unknown Obstructions During Excavation	Potential interference with unmarked and unknown obstructions found during the construction excavation or drawing inaccuracies potentially delaying construction and resulting in additional cost.	$18,000	6	No	A turkey burial ground was encountered requiring additional work and time to move around.
83	23970	V-028 Valve Auto - Half Moon Bay Tap, 2V, Ph. 1	Ctr Cst	Low Estimate	Specific cost assumptions in the Job Estimate proved to be inaccurate.	$100,000	N/A	Yes	The job estimating model for smaller jobs such as this where the current valve is being automated versus a replacement, etc. will be adjusted for future estimates.
84	23601	V-014 Valve Auto - Sand Hill, 2V, Ph. 1	Ctr Cst	Clearance	Additional work hours or resources may be required to adequately support a large customer load during clearance and to meet potentially tight clearance windows.	$200,000	12	Yes	Delays in obtaining system/pipeline clearance dates in 2012 and in station/commissioning clearances in 2013 due to resource constraints resulted in additional permitting/land acquisition costs.
85	23807	R-041 DFM-1020-01 REPL 2.69mi MP 0.00-2.69 PH1 8" Dist.	North	Weather Impacts	Potential construction delays and resulting additional costs due to rain days. Potential rain interaction with species (e.g. CTS breading migration) delaying construction and increasing cost.	$95,000	N/A	Yes	Poor weather caused delays to the project and required increased man- hours, including overtime, from the GC crew to finish the project.
86	23807	R-041 DFM-1020-01 REPL 2.69mi MP 0.00-2.69 PH1 8" Dist.	North	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$300,000	N/A	Yes	In a portion of the project where a new regulator station was being installed, approximately 800 feet of very hard sand stone was encountered which required hand digging. This also contributed to increased labor costs as more man-hours were required for this slower digging method.
87	23606	V-019 Valve Auto - Martin Station, 4V, Ph. 1	Bay	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$100,000	60	No	Construction was delayed due to material delivery delays resulting from late order placement.

TABLE 19-1
PACIFIC GAS AND ELECTRIC COMPANY
COST IMPACTS BY PROJECT
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	New PSRS	Project Description	Region	Risk	Description	Cost Impact ($)	Schedule Impact (days)	>10% Variance	Comments
88	23606	V-019 Valve Auto - Martin Station, 4V, Ph. 1	Bay	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$100,000	60	No	Construction was delayed because the initial plan was to have G.C. do the construction work, but G.C. did not have availability when needed so the work was expedited via direct award to a contractor (under master service agreement outside of Contractor Alliance).
89	23604	V-017 Valve Auto - Sullivan Ave, 1V, Ph. 1	Bay	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$50,000	60	No	Construction was delayed due to material delivery delays resulting from late order placement.
90	23604	V-017 Valve Auto - Sullivan Ave, 1V, Ph. 1	Bay	Productivity Impacts	Potential impacts to contractor productivity caused by multiple issues which may result in contractor moving to another construction location on-site or other methods of mitigation.	$50,000	60	No	Construction was delayed because the initial plan was to have G.C. do the construction work, but G.C. did not have availability when needed so the work was expedited via direct award to a contractor (under master service agreement outside of Contractor Alliance).
91	24284	V-032 Valve Auto - SP3-Line 191 Mtr Sta, 4V, Ph 1	Bay	Environmental/Species Impacts	Potential delays in construction due to the presence of protected or endangered species at the construction site.	$40,000	N/A	No	Red-Legged Frogs were identified to be in the area so additional monitoring was required during construction.
92	28407	T-207-13, Line L-187, Greenfield	Ctr Cst	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$20,000	N/A	No	A camera was run through the line in order to locate a pressure control fitting.
93	28407	T-207-13, Line L-187, Greenfield	Ctr Cst	Changes After IFB	Any changes to the project that were excluded from or occurred after IFB.	$20,000	N/A	No	A bell hole was expanded in order to run a camera to confirm a service tap location and that it had been cut off.
94	24288	V-038 Valve Auto - San Pablo, 3V, Ph. 1	Bay	Opportunity: Construction Resources	Making use of alternate resources to execute construction may result in cost savings.	$310,000	N/A	No	G. C. resources were used for construction in lieu of a contractor, saving on inspection, construction management and construction crew costs. The project also went very smoothly just as planned so none of the contingency put into the Job Estimate to cover potential realized risks was required.
95	23649	V-051 Valve Auto - Fairway Avenue, 2V, Ph. 1	Ctr Cst	Opportunity: Construction Resources	Making use of alternate resources to execute construction may result in cost savings.	$334,000	N/A	No	G. C. resources were used for construction in lieu of a contractor, saving on inspection, construction management and construction crew costs. The project also went very smoothly just as planned so none of the contingency put into the Job Estimate to cover potential realized risks was required.
96	23604	V-017 Valve Auto - Sullivan Ave, 1V, Ph. 1	Bay	Opportunity: Coordination of Work	Coordination of work with another project in the vicinity to save on costs such as: personnel, mobilization and de-mobilization costs.	$218,000	N/A	No	A decision was approved to replace rather than update existing valves and to combine this work with concurrent GT&S-funded station rebuild project. The savings against job estimate reflect a cost reduction compared to completing the work on a stand-alone basis.
97	23606	V-019 Valve Auto - Martin Station, 4V, Ph. 1	Bay	Opportunity: Coordination of Work	Coordination of work with another project in the vicinity to save on costs such as: personnel, mobilization and de-mobilization costs.	$400,000	N/A	No	A decision was approved to replace rather than update existing valves and to combine this work with concurrent GT&S-funded station rebuild project. The savings against job estimate reflect a cost reduction compared to completing the work on a stand-alone basis.
98	23600	V-013 Valve Auto - Hamlin Court, 1V, Ph. 1	Ctr Cst	Opportunity: Coordination of Work	Coordination of work with another project in the vicinity to save on costs such as: personnel, mobilization and de-mobilization costs.	$100,000	N/A	No	With the exception of installation of the electric service at the site construction was completed in 2012 in conjunction with R-27 on L-109_1 Spread 4 saving construction costs. Long lead encroachment permits for easements necessary for the electric service installation were the cause for the delay in commissioning the valve until 2013, but fortunately the cost impact of that delay was minimal so cost savings were still realized.
99	27652	TIM-273-13, Line DFM-7226-01, Modesto	Ctr Vly	Opportunity: Coordination of Work	Coordination of work with another project in the vicinity to save on costs such as: personnel, mobilization and de-mobilization costs.	$100,000	N/A	No	
100	25904	T-101-12, Line DFM-3010-01, Antioch	Bay	Opportunity: Scope Reduction After IFB	Changes to the project that occurred after IFB resulting in scope reduction and cost savings.	$510,000	N/A	No	The test was shortened by 0.11 miles (15%) as a result of data validation so a nitrogen test was completed instead of a hydrotest which also shortened the clearance window from 14 to 3 days. These changes resulted in significant construction, water and pigging cost savings.

TABLE 20-1
PACIFIC GAS AND ELECTRIC COMPANY
PSEP COSTS, AUTHORIZED AND SHAREHOLDER-FUNDED AMOUNTS BY ACTIVITY

All values in millions of dollars

	Actual Costs (a)										Customer Recovery Authorized (b)					Shareholder-Funded									
PSEP Expense	**4/1/2011 - 12/31/2011**	**2012**	**2013 YTD**	**2013 JAN**	**2013 FEB**	**2013 MAR**	**2013 APR**	**2013 MAY**	**2013 JUN**	**Total 4/1/2011 - 6/30/2013**	**4/1/2011 - 12/31/2011**	**2012**	**2013**	**2014**	**Total 4/1/2011- 12/31/2014**	**4/1/2011 - 12/31/2011**	**2012**	**2013 YTD**	**2013 JAN**	**2013 FEB**	**2013 MAR**	**2013 APR**	**2013 MAY**	**2013 JUN**	**Total 4/1/2011 - 6/30/2013**
Pipeline Modernization																									
Pipe Replacement	0.0	0.0	0.1	0.0	0.0	(0.0)	0.0	0.0	0.0	0.1															
In Line Inspection Pipeline Retrofit	0.0	0.0	1.1	0.0	0.0	0.1	0.5	(0.0)	0.4	1.1															
Strength Test																									
Pre-1955 Installation	228.2	130.7	32.1	0.6	3.1	1.7	6.9	9.1	10.7	407.7															
Post-1955 Installation			16.7	1.4	0.9	1.7	0.8	5.3	6.6																
Strength Test Total	228.2	130.7	48.8	2.0	4.1	3.4	7.7	14.3	17.3	407.7															
Eng Cond / Fatigue Analysis	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0															
Pipeline Modernization Total	228.2	130.7	50.0	2.1	4.1	3.5	8.2	14.3	17.7	408.8	0.0	2.3	65.9	81.3	149.5	228.2	128.4	17.0	1.5	1.0	1.8	0.9	6.5	5.4	373.6
Pipeline Records Integration																									
MAOP	90.5	120.3	27.7	4.6	5.5	6.9	6.0	4.9	(0.2)	238.4															
Mariner	1.2	3.8	1.1	0.4	0.5	0.8	1.7	(0.6)	(1.6)	6.0															
Pipeline Records Integration Total	91.6	124.1	28.7	4.9	6.0	7.7	7.7	4.3	(1.8)	244.4	0.0	0.0	0.0	0.0	0.0	91.6	124.1	28.7	4.9	6.0	7.7	7.7	4.3	(1.8)	244.4
Valve Automation	0.0	0.5	0.9	0.1	0.3	0.2	0.1	0.2	0.1	1.5	0.0	0.1	3.0	3.6	6.7	0.0	0.4	0.0	0.0	0.1	0.1	(0.2)	(0.0)	0.0	0.4
Interim Safety Measures	0.0	2.4	0.8	0.0	0.0	0.5	0.3	0.0	(0.0)	3.2	0.0	0.0	1.1	1.0	2.1	0.0	2.4	0.2	(0.1)	(0.0)	0.4	0.2	(0.1)	(0.1)	2.6
PMO	5.0	6.5	1.3	0.2	0.1	0.0	0.3	0.3	0.3	12.8	0.0	0.2	3.3	3.2	6.7	5.0	6.4	0.1	0.2	(0.1)	(0.3)	0.2	0.1	(0.0)	11.4
Other	6.8	6.3	0.7	0.3	0.3	0.7	0.3	(1.3)	0.3	13.8	0.0	0.0	0.0	0.0	0.0	6.8	6.3	0.7	0.3	0.3	0.7	0.3	(1.3)	0.3	13.8
Total PSEP Expense	**331.7**	**270.4**	**82.4**	**7.6**	**10.9**	**12.6**	**17.0**	**17.7**	**16.6**	**684.5**	**0.0**	**2.6**	**73.3**	**89.1**	**165.0**	**331.7**	**267.9**	**46.8**	**6.8**	**7.3**	**10.4**	**9.1**	**9.4**	**3.8**	**646.3**
PSEP Capital																									
Pipeline Modernization																									
Pipeline Replacement																									
Pipeline Replacement less Post-1955 Strength Test Cost	11.5	226.0	125.0	15.5	11.6	16.5	21.4	34.4	25.5	362.5															
Post-1955 Strength Test Cost	0.0	2.1	5.0	2.5	0.0	0.0	(0.5)	0.3	2.7	7.1															
Pipeline Replacement Total	11.5	228.1	130.0	18.0	11.6	16.5	20.9	34.7	28.2	369.6															
Strength Test Related	5.9	12.3	8.7	1.0	0.7	0.1	(1.3)	4.9	3.2	26.8															
In Line Inspection Retrofitting	0.6	16.0	18.6	2.0	3.9	5.5	2.2	2.7	2.3	35.2															
Pipeline Modernization Total	18.0	256.4	157.2	21.0	16.2	22.1	21.9	42.3	33.8	431.7	30.5	214.9	290.1	317.0	852.5	0.0	2.1	5.0	2.5	0.0	0.0	(0.5)	0.3	2.7	7.1
Pipeline Records Integration																									
MAOP	1.7	0.3	0.0	0.0	0.0	0.0	0.1	0.0	0.0	2.0															
Mariner	4.9	29.3	15.7	2.3	1.2	3.7	0.6	3.7	4.1	49.9															
Pipeline Records Integration Total	6.5	29.6	15.8	2.3	1.2	3.8	0.7	3.7	4.1	51.9	0.0	0.0	0.0	0.0	0.0	6.5	29.6	15.8	2.3	1.2	3.8	0.7	3.7	4.1	51.9
Valve Automation	13.0	27.2	17.8	1.3	2.6	2.0	2.7	4.1	5.1	58.0	13.7	38.9	51.6	24.8	129.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Interim Safety Measures	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PMO	2.3	2.1	4.6	0.6	0.4	0.9	0.8	1.0	0.9	8.9	3.0	6.5	6.5	6.3	22.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	3.0	2.4	0.8	0.7	0.8	0.0	0.1	(0.0)	5.3	0.0	0.0	0.0	0.0	0.0	0.0	3.0	2.4	0.8	0.7	0.8	0.0	0.1	(0.0)	5.3
Total PSEP Capital	**39.8**	**318.2**	**197.7**	**26.1**	**21.0**	**29.6**	**26.1**	**51.1**	**43.9**	**555.7**	**47.2**	**260.3**	**348.2**	**348.1**	**1003.8**	**6.5**	**34.6**	**23.2**	**5.6**	**1.9**	**4.5**	**0.2**	**4.1**	**6.8**	**64.3**
PSEP Expense and Capital Total	**371.5**	**588.6**	**280.1**	**33.7**	**31.9**	**42.2**	**43.1**	**68.8**	**60.5**	**1240.3**	**47.2**	**262.9**	**421.5**	**437.2**	**1168.8**	**338.2**	**302.5**	**70.0**	**12.4**	**9.2**	**14.9**	**9.3**	**13.5**	**10.6**	**710.5**

(a) PSEP cost amounts exclude costs associated with Stanpac and are subject to adjustment upon completion of project-close out activities.

(b) Amounts authorized for customer recovery are consistent with Authorized Program Expenses and Authorized Capital Costs presented in Attachment E to the December 2012 CPUC PSEP Decision, and are subject to update upon completion of PG&E's records validation process and subsequent Update Application filing, as directe the CPUC in Ordering Paragraph 11 of that decision. 2013 and 2014 authorized amounts reflect full year periods (January – December).

TABLE 22-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL MILEAGE OF PIPE REPLACED - FORECASTED AND ACTUAL
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	23825	26033	R-005 L-138 REPL 6.71mi MP 38.42-45.09 PH1	6.52	L-138	38.42	45.09	Fresno	Yes	2,3,Split	21-Nov-12	6-Jun-13
2	23832	26029	R-006 L-111A REPL 8.83MI MP 18.70-27.54 PH1	8.83	L-111A	18.7	27.54	Fresno	Yes	1,2,3,Split	17-Dec-12	28-Feb-13
3	23688	26045	R-018 L-114_2 REPL 1.72MI MP 9.03-10.52 PH1	1.72	L-114_2	9.03	10.52	Oakley	Yes	3	12-Jan-13	12-Jan-13
4	23724	25727	R-022 L-109_2A REPL 3.26mi MP 13.65-16.93 PH1	3.46	L-109_2A	13.65	16.93	Palo Alto/Stanford	Yes	3	16-Dec-12	19-Jun-13
5	23365	23366	R-029 L-109 REPL 0.58 MI MP 9.27-9.87 Spread 6A	0.56	L-109	9.27	9.87	Mountain View	Yes	3	18-Dec-12	18-Dec-12
6	23807	23807	R-041 DFM-1020-01 REPL 2.69mi MP 0.00-2.69 PH1 8" Dist.	2.69	DFM-1020-01	0	2.69	Butte	No	2,3,SPLIT	14-Jan-13	14-Jan-13
7	24909	24909	R-043 SP4Z RETIRE 0.22mi MP 8.18-8.43 PH1	0.22	SP4Z	8.18	8.43	Oakley	Yes	3,SPLIT	12-Apr-13	24-Apr-13
8	23862	23862	R-071 DFM-1502-08 REPL 0.52MI MP 0.01-0.52 PH1	0.52	DFM-1502-08	0.01	0.52	Yuba	No	2,Split	21-Dec-12	3-Jan-13
9	23874	26442	R-100 L-131 RETIRE 0.37MI MP 8.56-8.93 PH1	0.37	L-131	8.56	8.93	Oakley	Yes	3	29-Mar-13	24-Apr-13
10	N/A	25791	R-114 L-114 RETIRE 0.83 MP 8.18-8.92 PH1	0.83	L-114	8.18	8.92	Oakley	Yes	2	12-Apr-13	24-Apr-13
11	24902	27712	R-131 L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	0.03	L-119B-1	0	0.03	Sacramento	Yes	3,SPLIT	14-May-13	14-Jun-13
12	24903	24903	R-139 L-131Y REPL 0.01MI MP 0.53-0.54 PH1	0.01	L-131Y	0.53	0.54	Brannan Isld Park	No	3	10-May-13	10-May-13

TABLE 23-2
PACIFIC GAS AND ELECTRIC COMPANY
TOTAL MILEAGE OF PIPE STRENGTH TESTED - FORECASTED AND ACTUAL
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	N/A	28473	T-038B-11, Line L-132, Daly City	0.02	L-132	46.6059	46.608	Daly City	Yes	3	23-Feb-13	25-Feb-13
2	24183	25897	TIM-042-12, Line L-057A-MD1, McDonald Island	0.61	L-057A-MD1	0.0043	0.616	McDonald Island	Yes	1	25-Jan-13	15-Feb-13
3	24183	25896	TIM-043-12, Line L-057A-MD1, McDonald Island	0.16	L-057A-MD1	0.97	1.13	McDonald Island	Yes	1	25-Jan-13	15-Feb-13
4	23905	25904	T-101-12, Line DFM-3010-01, Antioch	0.61	DFM-3010-01	0.64	1.27	Antioch	Yes	3	1-Feb-13	4-Feb-13
5	23554	25866	T-082-12, Line L-119B, Sacramento	1.35	L-119B	8.89	10.15	Sacramento	Yes	3	14-Apr-13	27-Apr-13
6	N/A	28245	T-279-13, Line SP4Z, Antioch	0.45	SP4Z	8.43	8.93	Antioch	Yes	3	12-Apr-13	1-May-13
7	23874	25841	T-015-12, Line L-131_2, Oakley	0.13	L-131_2	8.45	8.58	Oakley	Yes	3	28-Mar-13	1-May-13
8	23876	27613	T-226-13, Line DFM-0817-01, San Jose	0.46	DFM-0817-01	0	0.4687	San Jose	Yes	3	22-Mar-13	4-Apr-13
9	24216	25884	T-093-12, Line L-210C, Vallejo	0.41	L-210C	31.27	31.68	Vallejo	Yes	3	19-Apr-13	4-May-13
10	23524	28395	T-206-13, Line L-187, King City	10.24	L-187	22.82	33.04	King City	Yes	1,3	29-Apr-13	20-May-13
11	23510	25902	T-046-12, Line L-138, Fresno	2.46	L-138	35.91	38.38	Fresno	No	1,2	3-May-13	24-May-13
12	23532	27604	T-218-13, Line L-021B, Napa	2.68	L-021B	0.01	2.31	Napa	Yes	1,2,3	13-May-13	8-Jun-13
13	23483	23483	T-360-14, Line DFM-7226-13, Modesto	0.25	DFM-7226-13	0	0.25	Modesto	No	3	15-May-13	8-Jun-13
14	23478	27652	TIM-273-13, Line DFM-7226-01, Modesto	4.59	DFM-7226-01	0	4.59	Modesto	Yes	3	15-May-13	8-Jun-13
15	23560	23560	T-310-14, Line DFM-0141-01, Crockett	0.43	DFM-0141-01	0	0.43	Crockett	No	3	17-May-13	19-May-13
16	23524	28407	T-207-13, Line L-187, Greenfield	7.98	L-187	33.04	41.08	Greenfield	Yes	1,2,3	24-May-13	13-Jun-13
17	23524	28408	T-208A-13, Line L-187, Soledad	1.6	L-187	41.08	42.64	Soledad	Yes	2,3	21-Jun-13	28-Jun-13
18	23550	27615	T-229A-13, Line L-118B, Madera	0.26	L-118B	8.46	8.72	Madera	Yes	3	14-Jun-13	21-Jun-13
19	23565	27609	T-224A-13, Line DFM-0604-01, Vacaville	0.79	DFM-0604-01	3.926	4.711	Vacaville	Yes	3	6-Jun-13	21-Jun-13
20	23749	27653	TIM-274-13, Line GCUST5900, Fremont	0.98	GCUST5900	0.01	0.99	Fremont	Yes	3	13-Jun-13	15-Jun-13

TABLE 25-1
PACIFIC GAS AND ELECTRIC COMPANY
COMPLETED VALVE AUTOMATION AND IN-LINE INSPECTION PROJECTS
JANUARY 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	Miles Completed / Valves Automated	Line	MP1	MP2	City	HCA	Class Code	Clearance Date	Tie-in Date
1	23600	23600	V-013 Valve Auto - Hamlin Court, 1V, Ph. 1	1	N/A	N/A	N/A	Sunnyvale	N/A	N/A	26-Oct-12	1-Apr-13
2	23606	23606	V-019 Valve Auto - Martin Station, 4V, Ph. 1	4	N/A	N/A	N/A	Daly City	N/A	N/A	25-Apr-13	25-Apr-13
3	23604	23604	V-017 Valve Auto - Sullivan Ave, 1V, Ph. 1	1	N/A	N/A	N/A	Daly City	N/A	N/A	6-Apr-13	6-Apr-13
4	23601	23601	V-014 Valve Auto - Sand Hill, 2V, Ph. 1	2	N/A	N/A	N/A	Menlo Park	N/A	N/A	1-Dec-12	16-Apr-13
5	23970	23970	V-028 Valve Auto - Half Moon Bay Tap, 2V, Ph. 1	2	N/A	N/A	N/A	San Mateo	N/A	N/A	13-Feb-13	13-Feb-13
6	24284	24284	V-032 Valve Auto - SP3-Line 191 Mtr Sta, 4V, Ph 1	4	N/A	N/A	N/A	Pittsburg	N/A	N/A	19-Mar-13	19-Mar-13
7	24288	24288	V-038 Valve Auto - San Pablo, 3V, Ph. 1	3	N/A	N/A	N/A	San Pablo	N/A	N/A	18-Apr-13	18-Apr-13
8	23649	23649	V-051 Valve Auto - Fairway Avenue, 2V, Ph. 1	2	N/A	N/A	N/A	San Leandro	N/A	N/A	28-Jun-13	28-Jun-13
9	24022	29709	L-300A MP 352.3-391.2 ILI & ANALYSIS	39	L-300A	352.3	391.2	Fresno	Yes	1	3-Apr-13	15-Apr-13

TABLE 26-1
PACIFIC GAS AND ELECTRIC COMPANY
FORECAST PROJECTS NOT COMPLETED OR REPLACED BY HIGHER PRIORITY PROJECTS
REPORTING PERIOD APRIL 1, 2013 – JUNE 30, 2013

Line #	PSEP Filing PSRS	New PSRS	Project Description	PSEP Filing Year	Current Status	Comments
1	24887	24887	DFM-1017-01 REPL 0.01MI MP 0.01-0.02 PH1	2013	Removed	Removed from PH1 due to records verified.
2	23801	23801	DFM-1815-15 REPL 0.01MI MP 1.38-1.39 PH1	2013	Removed	Removed from PH1 due to records verified.
3	23711	23711	DFM-1202-16 REPL 0.08MI MP 0.00-0.08 PH1	2013	Removed	Removed from PH1 due to records verified.
4	24898	24898	L-105N-3 REPL 0.03MI MP 0.00-0.00 PH1	2013	Removed	Removed as replacement project and new nitrogen test project created for cost efficiency reasons because the line runs under a railroad.
5	23888	23888	L-116 REPL 0.04MI MP 0.00-0.03 PH1	2013	Removed	Removed and segments transferred to be abandoned with nearby replacement project (R-150, PSRS 29216) for efficiency reasons.
6	23930	23930	DFM-0627-01 REPL 0.02MI MP 0.00-0.02 PH1	2013	Removed	Removed and segment transferred to nearby replacement project (R-150, PSRS 29216) for efficiency reasons.
7	23699	23699	DFM-3022-01 REPL 0.01MI MP 0.00-0.00 PH1	2013	Removed	Removed from PH1 to a future phase due to records verified.
8	24285	24285	VALVE AUTO - CONCORD METER STA, PH. 1	2013	Removed	Valve automation project originally filed as two separate projects due to proposed split of funding between PG&E and Stanpac. Valve Automation was subsequently determined as fully funded by Stanpac and will proceed solely under the Stanpac filed PSRS/order number (23623/97000504).
9	23761	23761	DFM-1817-01 REPL 0.01MI MP 0.00-0.00 PH1	2013	Removed	Removed from PH1 due to records verified.
10	23751	23751	DFM-1406-01 REPL 0.01MI MP 0.00-0.01 PH1	2013	Removed	Removed from PH1 due to records verified.
11	24888	24888	DFM-1302-01 REPL 0.01MI MP 0.00-0.00 PH1	2013	Removed	Removed from PH1 due to records verified.
12	23760	23760	DFM-0611-08 REPL 0.06MI MP 0.00-0.06 PH1	2013	Removed	Remove as replacement project and add to test on nearby line (PSRS 28513) for efficiency reasons, then test removed from PH1 due to records verified.
13	23849	23849	DFM-0404-11 REPL 0.04MI MP 0.00-0.04 PH1	2013	Removed	Removed from PH1 due to records verified.
14	24901	24901	L-118-1 REPL 0.02MI MP 0.01-0.03 PH1	2013	Removed	Removed from PH1 due to records verified.
15	23830	23830	DFM-1302-02 REPL 0.01MI MP 0.00-0.00 PH1	2013	Removed	Removed from PH1 due to records verified.
16	23827	23827	DFM-1615-07 REPL 0.01MI MP 0.00-0.01 PH1	2013	Removed	Removed from PH1 due to records verified.
17	23686	23686	DFM-1202-12 REPL 0.01MI MP 1.91-1.92 PH1	2013	Removed	Removed from PH1 due to records verified.
18	24283	24283	VALVE AUTO - ANTIOCH TOWN MTR STA, PH. 1	2013	Removed	Valve Automation site selected at California Ave (1 of 2) will be automated instead of Antioch Town Meter Station for constructability and cost reasons.
19	23620	23620	VALVE AUTO - ANTIOCH TOWN MTR STA, PH. 1	2013	Removed	Valve Automation site selected at Delta Fair (1 of 2) instead of Antioch Town Meter Station for constructability and cost reasons.
20	23726	23726	DFM-1220-01 REPL 0.01MI MP 0.86-0.87 PH1	2013	Removed	Removed from PH1 due to records verified.
21	24904	24904	L-132B REPL 0.01MI MP 0.01-0.01 PH1	2013	Removed	Removed from PH1 due to records verified.
22	23630	23630	VALVE AUTO - CRYSTAL RANCH, PH. 1	2013	Removed	Valve Automation site selected at Clayton Reg Sta instead of Crystal Ranch for constructability and cost reasons.
23	24891	24891	DFM-1805-01 REPL 0.03MI MP 0.00-0.03 PH1	2013	Removed	Removed from PH1 due to records verified.
24	24893	24893	DFM-2412-01 REPL 0.01MI MP 0.00-0.00 PH1	2013	Removed	Removed from PH1 to a future phase due to records verified.
25	24896	24896	DFM-8832-01 REPL 0.02MI MP 0.00-0.01 PH1	2013	Removed	Removed from PH1 to a future phase due to records verified.
26	23481	23481	T-255-13, Line DFM-7226-02, Tracy	2013	Removed	Removed from PH1 due to records verified.
27	23477	23477	DFM-7224-12 TEST TIM 0.48MI MP 0.25-0.73 PH1	2013	Removed	Removed from PH1 due to records verified.
28	23802	30329	DFM-1306-01 REPL 0.00MI MP 4.19-4.19 PH1	2013	Delayed	Delayed from 2013 to 2014 to allow more time for MAOP to locate as-builts that could remove this segment from PH1.