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DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

DRA Report on the Pipeline Safety Enhancement Plan of Pacific Gas and Electric Company

Gas Transmission Valve Automation Program
Interim Safety Enhancement Measures
Implementation Plan Management Approach

San Francisco, California
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574256

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I. INTRODUCTION

Pacific Gas and Electric Company's ("PG&E") Pipeline Safety Enhancement Plan ("PSEP" or "Implementation Plan"), that was required by California Public Utilities Commission ("CPUC" or "Commission") Decision ("D".) 11-06-017, included testimony to support a Valve Automation Program, Interim Safety Enhancement Measures, and a Program Management Office ("PMO").

In aggregate, PG&E forecasts capital expenditures and expenses of $181.6 million for these three programs of the Implementation Plan over four years as shown in Table 7-1.

Table 7-1
PG&E Forecasted Valve Automation, Interim Safety, and Program Management Office Capital Expenditures and Expense
(in millions of dollars)

	2011	2012	2013	2014	Total
Valve Automation	15.3	42.1	56.4	29.8	143.6
Interim Safety Enhancement Measures	0.0	1.0	1.1	1.1	3.2
Program Management Office	4.6	10.1	10.1	10.0	34.8
Total	19.9	53.2	67.6	40.9	181.6

II. SUMMARY OF RECOMMENDATIONS

The Division of Ratepayer Advocates ("DRA") recommends a $90.4 million cost forecast (as compared to PG&E's $181.6 million request) to be a reasonable estimate for implementing the priority Valve Automation projects, Interim Safety Enhancement Measures, and Program Management Office included in PG&E's PSEP.[1] DRA's recommendation includes expenditures for the automation of all the

[1] DRA's primary cost recovery recommendations are included in Exhibit DRA-02 and supersede all other related cost recovery recommendations found in this exhibit (DRA-07). DRA's comparative analysis of PG&E's PSEP Phase 1 Forecasted Valve Automation, Interim Safety, and Program Management Office Capital Expenditures and Expenses with DRA's recommended changes is
(continued on next page)

existing valves required under the federal standard and the installation of new automatic valves on pipelines that cross active earthquake faults, interim safety expenditures, and program management office expenditures.

DRA recommends that the valve automation program in Phase 1[2] of PG&E's PSEP include only automating existing valves and installing new automated valves on pipelines that cross active earthquake faults, which are consistent with existing laws and regulations. Other valve enhancement projects recommended by PG&E, which include replacement of an existing valve to include automation, installation of a new valve with automation, upgrade of existing automated valve hardware, and automation or replacement of existing valve in vault,[3] should be postponed to a later phase of the PSEP or the next rate case because they are above and beyond the requirements of D.11-06-017, and the associated cost estimates are highly uncertain at this time. The comparison of PG&E and DRA costs for the valve automation program is shown in Table 7-2.

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responsive to the Commission's Amended Scoping Memo request for parties to address the reasonableness of the utilities Implementation Plans and the associated cost estimates.

[2] Phase 1 will focus on pipelines in Class 4 areas, and larger diameter, higher pressure pipelines located in highly populated Class 3 areas. (PG&E Prepared Testimony page 4-3). Under federal code governing pipeline safety, a Class 4 has the highest population density and is defined as "any class location unit where buildings with four or more stories above ground are prevalent." Class 3 is the next highest population density class location and is defined as "any class location unit that has 46 or more buildings intended for human occupancy, or a small well-defined outside area that is occupied by 20 or more persons" for a greater than a certain amount of time. (PG&E Prepared Testimony, page 4-13).

[3] PG&E Prepared Testimony at pages 4-51 to 4-52 describes the valve automation types. In summary: (1) Automating an existing valve mounts a new actuator onto an existing valve; (2) Replacement of an existing valve requires removal of an existing valve and the installation of an automated valve assembly; (3) Installation of new valves refers to installation of a new valve not previously in service; (4) Upgrade of existing automated valves is where the existing valve already is automated, but existing hardware and/or software will be upgraded; and (5) Automation of or replacement of existing valve in vault refers to automating valves which may require installation of a large vault(s) installed below ground under roadway pavement.

Note: Throughout this exhibit, DRA includes forecasted capital expenditures and expenses for 2011 as if the year has not passed. This provides an apples to apples comparison between PG&E's request, as filed, and DRA's recommendations.

Table 7-2
Valve Automation Program PG&E vs DRA
(in millions of dollars)

	2011	2012	2013	2014	Total
PG&E Request	15.3	42.1	56.4	29.8	143.6
DRA Recommended	8.7	11.0	22.4	12.4	54.5

DRA also recommends that PG&E's proposal to establish four gas engineer positions associated with the interim safety enhancement measures be rejected. PG&E has not shown that these positions are necessary, as PG&E is already meeting its pressure reduction requirements with its current number of engineering staff. PG&E and DRA costs are shown in Table 7-3.

Table 7-3
Interim Safety Enhancement Measures - PG&E vs DRA
(in millions of dollars)

	2011	2012	2013	2014	Total
PG&E Request	0	1.0	1.1	1.1	3.2
DRA Recommendation	0	0.4	0.4	0.4	1.1

DRA does not object to PG&E's cost estimate for its PMO, as shown in Table 7-4.

Table 7-4
Program Management Office – PG&E vs DRA
(in millions of dollars)

	2011	2012	2013	2014	Total
PG&E Request	4.6	10.1	10.1	10	34.8
DRA Recommendation	4.6	10.1	10.1	10	34.8

III. DISCUSSION / ANALYSIS OF DRA RECOMMENDATIONS

A. Valve Automation

The Valve Automation Program expands PG&E's use of automated pipeline system isolation valves ("automated valves"). PG&E proposes to install Remote Control Valves ("RCV"), which are remotely triggered by operators in PG&E's Gas

Control Center, in heavily populated areas. PG&E proposes to install Automatic Shut-off Valves ("ASV"), which are automatically triggered by local controls at the valve site, on pipelines in populated areas that cross active earthquake faults where the fault poses a significant threat to the pipeline.[4] According to PG&E, both types of automated valves, RCVs and ASVs, will provide for the quick shutoff of gas to pipeline segments in the event of a pipeline rupture. PG&E will also upgrade its Supervisory Control and Data Acquisition ("SCADA") system to allow operators in its Gas Control Center to identify and respond quickly if a line rupture occurs.[5] Additionally, PG&E proposes to install new flow meters to provide gas flow information to facilitate the decision making on when to isolate a pipe segment.[6]

1. PG&E requests that the Commission adopt Valve Automation Program expenditures of $143.6 million

PG&E requests that the Commission adopt Valve Automation Program capital expenditures and expense forecasts totaling $143.6 million for 2011 to 2014, as shown in Table 7-5.[7]

[4] PG&E Prepared Testimony, page 4-1.

[5] PG&E Prepared Testimony, page 4-2.

[6] PG&E Prepared Testimony, page 4-38.

[7] PG&E Prepared Testimony, page 4-7.

Table 7-5
PG&E Forecasted Valve Automation Program
Capital Expenditures and Expense
(in millions of dollars)

		2011	2012	2013	2014	Total
Capital	Valve Automation – SCADA	0.0	4.2	5.5	3.5	13.2
Capital	Valve Automation	13.7	33.4	43.2	22.5	112.7
Capital	Valve Automation – StanPAC	0.0	1.9	4.6	0.0	6.6
Expense	SCADA Enhancement & O&M	1.6	2.6	3.1	3.8	11.1
Total	Valve Automation	15.3	42.1	56.4	29.8	143.6

2. DRA recommends a Valve Automation Program cost forecast of $54.5 million as reasonable.

DRA recommends a $54.5 million cost forecast (compared to PG&E's $143.6 million request) to be a reasonable estimate for PG&E's Valve Automation Program capital and expense expenditures. DRA's recommendation accounts for automation of existing valves and new automatic valves for pipelines that cross active earthquake faults. In addition, DRA agrees with PG&E's capital related flow metering costs. DRA made adjustments to PG&E's SCADA forecasts related to expenses. Table 7-6 summarizes DRA's Valve Automation Program recommendation. Table 7-7 shows the difference between PG&E's forecast and DRA's recommendation.

Table 7-6
DRA Recommended Valve Automation Program
Capital Expenditures and Expense Forecast
(in millions of dollars)

		2011	2012	2013	2014	Total
Capital	Valve Automation – SCADA	0.0	4.2	5.5	3.5	13.2
Capital	Valve Automation	7.0	5.1	13.6	8.0	33.7
Capital	Valve Automation – StanPAC	0.0	0.5	2.1	0.0	2.6
Expense	SCADA Enhancement & O&M	1.6	1.3	1.2	0.9	5.0
Total	Valve Automation	8.7	11.0	22.4	12.4	54.5

Table 7-7
Difference Between PG&E and DRA Recommended Valve Automation Program
(in millions of dollars)

		2011	2012	2013	2014	Total
Capital	Valve Automation – SCADA	0.0	0.0	0.0	0.0	0.0
Capital	Valve Automation	-6.6	-28.4	-29.6	-14.5	-79.1
Capital	Valve Automation – StanPAC	0.0	-1.5	-2.5	0.0	-4.0
Expense	SCADA Enhancement & O&M	0.0	-1.3	-1.9	-2.9	-6.1
Total	Valve Automation	-6.6	-31.1	-34.0	-17.3	-89.1

3. The Commission should not rely on PG&E's Valve Automation Program cost estimates.

The Commission should not rely on PG&E's Valve Automation Program cost estimates. The cost estimates are conceptual, could not have been compared against historical valve projects, and the actual recorded costs from the eight valve automation launch projects[8] initiated in 2011 show a wide variance to the PSEP forecast and unit cost methodology.

Without a more accurate cost estimate, the Commission will be unable to fully consider the impact of these costs on the final adopted PSEP.[9]

1) PG&E does not have valve replacement-specific project cost history.

As part of the discovery process, DRA requested workpapers for valve related project that PG&E had completed from 2000 to 2010. PG&E responded that prior to the development of the PSEP, PG&E did not install any automated valves as stand-alone projects. Rather, the installation of RCVs and ASVs were included as part of larger pipeline projects and as such, the costs of the valve installation or automation were intertwined with other costs and not specifically tracked.[10]

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[8] PG&E commenced the Valve Automation Program in 2011 with a "launch" of 20 new automated valve installations. PG&E Prepared Testimony, page 4-3.

[9] D.11-06-017 p. 22 "…direct that the plans as set forth above must include cost estimates and rate impact to enable the Commission to FULLY CONSIDER the impacts of the final adopted plan." (Emphasis added.)

[10] PG&E data response GasPipelineSafetyOIR_DR_DRA_014-Q01.

Given PG&E's lack of historical cost data related to valve replacement, the cost estimates included in its PSEP application have no real basis for comparison and therefore can only be evaluated in terms of PG&E's methodology.

2) The PSEP cost estimates are conceptual.

The cost estimates included in the PSEP are concept evaluation and should not be relied on to represent the total cost of the Phase 1 program. As PG&E states in its testimony, the level of project definition was less than 15% at the time of the estimates' development.[11] The level of project definition defines maturity or the extent and types of input information available to the estimating process. Such inputs include project scope definition, requirements documents, specifications, project plans, drawings, calculations, learnings from past projects, reconnaissance data, and other information that must be developed to define the project.[12]

To develop its Valve Automation Program, PG&E collaborated with EN Engineering ("ENE") to evaluate where to add automated pipeline isolation capability, and the determination of the Phase 1 projects and their work scope.[13] ENE also provided PG&E with the Phase 1 cost estimate of the Valve Automation Program.[14] The estimated capital expenditures were Class 4 level estimates as defined in the Association for the Advancement of Cost Engineering ("AACE") International Recommended Practice No. 18R-97.[15]

An AACE Class 4 is typically identified as a "concept," where the scope is defined from 5 to 15 percent with a resulting cost estimate range of -30% to +50%. In its testimony, PG&E admits that its cost estimates are conceptual: "While PG&E's

[11] PG&E Prepared Testimony, page 4-50.

[12] PG&E Pipeline Safety Enhancement Plan Workpapers Supporting Chapter 7 Implementation Plan Management Approach and Estimate Risk Quantification Volume 1 of 2, page WP 7-17.

[13] PG&E Prepared Testimony, page 4-2.

[14] PG&E Prepared Testimony, page 4-49.

[15] PG&E Prepared Testimony, page 4-49.

original estimates are detailed, they are still conceptual in nature, with significant project scope in the process of being defined…."[16]

The Commission should require at least a Class 3 i.e. budget/authorization estimate before considering PG&E's request. AACE Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored.[17]

3) Wide variance exists between the PSEP cost forecast and actual costs.

As noted, PG&E retained ENE to estimate costs for Phase 1 of the Valve Automation Program. ENE identified unit costs for various materials, construction labor, and engineering tasks associated with each potential scope of work. These base units were then combined to develop cost estimates for each valve automation project.[18]

DRA compared these PSEP cost estimates against actual recorded costs, and forecasted cost at completion estimates[19] for eight launch projects as of December 4, 2011. As can be seen in Table 7-8 below, there is wide variance between the PSEP forecasted cost and the current forecast at completion estimate. Only one of the eight specified projects that used the applied unit costs method had a single-digit variance (Crossman Avenue). The other seven projects vary from a 42% cost overrun to a 51% cost underrun.

Given the wide variance on these eight projects, DRA questions the accuracy of the remaining 72 valve project cost estimates.

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[16] PG&E Prepared Testimony, p. 7-23, line 10.

[17] PG&E Pipeline Safety Enhancement Plan Workpapers Supporting Chapter 7 Implementation Plan Management Approach and Estimate Risk Quantification Volume 1 of 2, page WP 7-25.

[18] PG&E Prepared Testimony, p. 4-50.

[19] PG&E data response GasPipelineSafetyOIR_DR_DRA_027-Q01Atch01.xls.

Table 7-8

Comparison of Valve Automation PSEP Forecast to Forecast at Completion

Project Name	PSEP Filing Cost Estimate	Forecast at Completion	Actual thru 12/5	Variance Between Forecast at Completion and PSEP Filing Cost Estimate
Crossman Avenue	2,233,938	2,163,946	1,966,274	-3%
Healy Station	475,419	327,587	266,194	-31%
Larkspur	2,846,018	4,041,328	2,755,352	42%
Milpitas Terminal	2,827,679	2,018,618	1,396,409	-29%
Rengstorff-Total*	2,636,210	3,255,991	3,068,723	24%
San Andreas	975,772	634,578	567,281	-35%
SF Gas Load Center	1,194,799	623,472	535,258	-48%
Sierra Vista	936,575	457,311	387,441	-51%
Total 2011 Automation Work*	14,126,410	13,522,831	10,942,932	-4%
* Includes installation of flow meter at Rengstorff Station. Cost could not be segregated to match PSEP forecast.[20]				

4) PG&E's unit cost estimating methodology uses typical installation that may not be applicable.

DRA issued data requests related to cost underruns and overruns. In response to DRA data request JOH-007, question 3, PG&E states:

> The Valve Automation unit cost estimate method assumed a typical installation for various types of work. For the "Launch" projects, *some easier to execute valve automation projects were chosen*. This resulted in projects at Healy Station, Sierra Vista, San Francisco Gas Load Center, and San Andreas*, which did not require all the typical installation components*. All four of these sites already had power gas systems in place for use by the gas piston actuators, and required less trenching and controls installation work. This resulted in lower costs than the unit cost methodology estimated for these projects. For Milpitas Terminal, there was existing conduit in place that could be utilized for the valve automation work, which significantly reduced trenching and conduit installation work. For Crossman Avenue, the

[20] PG&E Data Response GasPiplineSafetyOIR_DR_DRA_051-Q05.

> work scope fairly well matched the unit cost estimate, and the forecast at completion is very close to the PSEP cost estimate.[21]

In response to question 4 of the same data request, PG&E stated:

> The unit cost estimate methodology assumes a typical installation for various types of work. Specific projects will be similar to the typical installation, but each will have unique components, which will create cost deviations from the unit cost estimate.
>
> For Larkspur and Rengstorff, the actual installations each required the replacement or the addition of multiple, manually operated valves and significant amounts of station piping *that the unit cost estimate did not capture*, but were required to accomplish the valve automation.
>
> In addition, for Larkspur, a pressure control fitting, *which was not in the original work plan*, had to be installed in Line 109 to allow the new mainline valve to be installed. Larkspur was also in a location that had difficult terrain and tight working space requirements that added to construction costs, and incurred some additional costs due to the delayed completion of pipeline hydrotesting work. Rengstorff required a multi-stage clearance to first install the replacement mainline valve and tap valves, and then to remove the existing mainline valve and tap valves, which added to clearance costs.[22]

DRA data request JOH-007 questions 3 and 4 were related to the launch projects' cost underruns and overruns, respectively. In both cases PG&E provided specific explanations for the actual costs being different from the PSEP forecast. For both the cost underruns and overruns, the response was that the "unit cost method assumed a typical installation for various types of work." But based on PG&E's response, seven of the eight launch projects were not typical installations. Four were "easier to execute" projects, one had "existing conduit that significantly reduced trenching and conduit installation," and two "required replacement or addition of manually operated valves that the unit cost method did not capture."

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[21] PG&E Data Request No.: DRA_051-03 (Emphasis added).

[22] PG&E Data Request No.: DRA_051-04 (Emphasis added).

Material costs were also underestimated. As PG&E stated in its data response: "In general, material costs for non-major bulk purchases instrumentation and controls materials (e.g. wire, conduit, controls rack framing materials) were underestimated for all eight projects."[23]

In addition, DRA questions the use of a different material burden rate for this PSEP filing. In this filing, PG&E assigns a material burden rate of 19%. However, in the last general rate case ("GRC"), PG&E used a different material burden rate[24].

For these reasons, PG&E's unit cost methodology currently does not provide results that the Commission should rely upon.

4. DRA recommends limiting Phase 1 Valve Automation Program to improving SCADA, automating existing valves, and installing automatic valves on pipelines that cross active earthquake faults.

Given the lack of historical cost data related to valve replacement, the conceptual nature of the cost estimate, and the wide variance of the eight 2011 launch projects, DRA recommends that the Commission take a conservative approach and approve the projects that DRA recommends for Phase 1 of PG&E's Valve Automation Program. This provides enhancements to SCADA and installation of flow meters, automating existing valves, and to installing automatic valves on pipelines that cross active earthquake faults. A proportional share of operations and maintenance expenses is also included, after disallowance.

Other valve projects to install new valves and valves in vaults, and replacement of existing valves to include automation, should be considered after PG&E can provide supported Class 3 estimates for each project. DRA recommends that PG&E resubmit these projects in a later phase of the PSEP or its next rate case.

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[23] PG&E data response GasPipelineSafeltyOIR_DR_DRA_051-Q02.

[24] In PG&E's response to DRA in PZS8-2, PG&E indicated that for the 2011 GT&S and GRC rate cases, the material burden rates were only up to 16% for electric and gas. In PG&E response of DRA in PZS-15-3, PG&E stated for the Valve Automation Program, a 19% burden rate was used and 10% additional was added for sales tax, which, taken together, resulted in the 29% material burden rate.

1) DRA recommendations are consistent with existing laws and regulations.

DRA's recommendation to limit Phase 1 valve automation to existing valves and for pipelines that cross active earthquake faults is consistent with existing laws and regulations. As PG&E stated in its data response: "PG&E is in compliance with valve spacing requirements specified in 49 CFR Section 192.179(a). All new and replacement pipeline and station work evaluates valve spacing to ensure properly spaced valves are provided as part of the preliminary engineering process."[25] And as PG&E stated in its Prepared Testimony: "Currently, there are no prescriptive requirements in the prevailing pipeline code, Title 49 CFR Part 192, that require operators to install automated valves."[26] California State Assembly Bill ("AB") 56 added Section 957 to the Public Utilities Code to require the installation of automatic shutoff or remote controlled sectionalized block valves on intrastate transmission lines that are located in a high consequence area and intrastate transmission lines that traverse an active seismic earthquake fault. AB 56 gives the Commission the authority to establish action timelines and to adopt standards for how to prioritize installation of automatic shutoff or remote controlled sectionalized block valves to ensure that remote and automatic shutoff valves are installed as quickly as is reasonably possible.[27] As such, DRA's recommendation for PG&E to automate existing valves and install new automatic valves for pipelines that cross active earthquake faults in Phase 1 meets and exceeds existing laws and regulations.

2) DRA recommends a $54.5 million cost forecast for PG&E's Valve Automation Program.

DRA recommends a $54.5 million cost forecast for PG&E's Valve Automation Program. While this amount represents 38% of PG&E's total Valve Automation

[25] PG&E Data Response GasPipelineSafetyOIR_DR_DRA_042-Q01.

[26] PG&E Prepared Testimony, page 4-32.

[27] Cal.Pub.Util. Code § 957 (2012).

Program request, it accounts for 100% of PG&E's flow metering projects, automation of 51 of 80 valve sites, and 42% of operations and maintenance.

(a) DRA does not object to PG&E's request to install new flow meters and remote valve position indicators.

DRA agrees with PG&E that if a pipeline leak or rupture occurs, the leak or rupture has to be detected.[28] As such, DRA does not object to PG&E's request to install 30 new flow meters and remote valve position indicators at a combined forecasted cost estimate of $13.2 million. The Commission's Consumer Protection and Safety Division ("CPSD") also recommends that the CPUC allow PG&E to proceed with the installation of telemetry facilities "…as these readings are crucial because they allow for pin-pointing failure locations and will assist in first response efforts to any failure events."[29]

(b) DRA recommends a $36.3 million cost forecast to automate 51 of 80 specific valve sites.

DRA recommends a $36.3 million cost forecast to complete work on 51 specific valve sites (out of 80 identified by PG&E[30]) to automate existing valves and to install new automatic valves that cross active earthquake faults. Automation of the other 29 specific valves sites should be reconsidered in a later phase of the PSEP or the next GRC because their cost estimates are highly uncertain as discussed in a previous section and they are above and beyond the requirement of D.11-06-017.

While DRA has reservations about the unit cost methodology used by PG&E to determine the Valve Automation Program cost estimates, DRA does not have the data at this time to offer an alternative. As such, DRA used PG&E's PSEP cost

[28] PG&E Prepared Testimony, page 4-26.

[29] Technical Report of the Consumer Protection and Safety Division Regarding Pacific Gas and Electric Company's Pipeline Safety Enhancement Plan, page 5.

[30] PG&E's Valve Automation Program contains work at 80 specific valve sites. PG&E Prepared Testimony, page 4-38.

estimates and made adjustments to determine the recommended amount of $36.3 million.

DRA's $36.3 million recommendation is based on adopting PG&E's PSEP cost forecast that results from PG&E's Earthquake Fault Crossing Decision Tree.[31] In addition to these earthquake fault crossing valve site projects, DRA added valve site projects that automated existing valves at 63% of PG&E's PSEP estimate. The 63% represents the average forecast at completion to the PSEP estimate of the four launch projects to automate existing valves that was initiated in 2011.

The 63% of PG&E's PSEP estimate is a better gauge of costs for automating an existing valve site as it represents the most recent historical cost information for valve replacement projects. Also, four of the eight launch projects are the same type of projects with the forecast at completion estimates falling into a closer grouping, as shown in Table 7-9 below.

Table 7-9

Comparison of PSEP Filing Cost Estimate to Forecast at Completion Cost Estimate by Category

Category	Number of Launch Projects	Variance	Average PSEP Estimate to Forecast at Completion Estimate
Automate	4	-20% to -51%	63%
New	2	+42% to -35%	122%
Replace	2	+24% to -3%	111%

(c) DRA recommends $4.2 million in SCADA enhancement expenses and operation and maintenance expenses.

PG&E proposes SCADA Enhancement expenses of $6.6 million[32] and automated valve and meter maintenance and operational expenses of $3.7 million.[33] PG&E states that SCADA enhancement and valve automation expense projects

[31] PG&E created two decision trees, one based on population density and the other based on earthquake fault crossings. PG&E Prepared Testimony, page 4-9.

[32] PG&E Prepared Testimony, page 4-66, Table 4-9.

consist primarily of efforts to develop new tools, processes and training for identification and response to pipeline ruptures by PG&E's System Gas Control Center and work to evaluate new technologies that could be utilized in detecting abnormal operating events.[34]

DRA recommends a $2.4 million cost forecast for SCADA Enhancement expenses and $1.9 million for maintenance and operational expenses. Table 7-10 compares PG&E's request and DRA's recommendation.[35]

Table 7-10
Comparison of PG&E Request and DRA Recommendation for SCADA Enhancement Expenses and Maintenance and Operation Expenses

	PG&E Total	DRA Total	Difference
SCADA Enhancement Expenses			
SCADA System Comprehensive Review	700,000	700,000	0
SCADA Dashboard Screens	503,330	503,330	0
Electronic Pin Map	407,700	407,700	0
Line Break Simulation Development	208,500	0	-208,500
Shutdown Protocols and Screens	431,166	0	-431,166
Situational Awareness Alarming	845,970	0	-845,970
Pipeline Simulator Definition and Assessment	235,750	235,750	0
Detection Technology Assessment	900,000	0	-900,000
Backup Communications Assessment	100,000	100,000	0
GIS/Historian Integration	1,665,300	0	-1,665,300
Gas M&C Automated Valve Training	296,400	296,400	0
Escalation	357,657	118,981	-238,676
Total	6,651,773	2,362,161	-4,289,612
Maintenance and Operational Expenses			
Valve/Meter Maintenance & Testing	262,080	144,144	-117,936
Pipe Segment Shutdown Training	28,700	0	-28,700
Electronic Pin Map Field Verification & Maintenance for New Valve Positions	143,500	78,925	-64,575
GIS/Historian Screen Maintenance	90,000	0	-90,000
Operators Additional Annual Training	65,625	0	-65,625

(continued from previous page)
[33] PG&E Prepared Testimony, page 4-66, Table 4-10.

[34] PG&E Prepared Testimony, page 4-65.

[35] PG&E's Implementation Plan Workpaper Supporting Chapter 4, Valve Automation, pages WP 4-279 to WP4-282 identified the tasks and associated cost. PG&E Prepared Testimony, pages 4-59 to 4-62 provided brief description on these tasks.

Additional Transmission Specialist	873,600	480,480	-393,120
Operations Cost	1,950,000	1,072,500	-877,500
Escalation	241,493	106,169	-135,324
Total	3,654,998	1,882,218	-1,772,780
Grand Total	10,306,771	4,244,379	-6,062,392

DRA made adjustments to PG&E's SCADA Enhancement and maintenance and operational expense request. Specifically, DRA removed expenses in Line Break Simulation Development, Shutdown Protocols and Screens, Situational Awareness Alarming, Pipe Segment Shutdown Training, and Operators Additional Annual Training. DRA removed these expenses because training expenses should be included in PG&E's GRC funding. As training should be a dynamic activity that incorporates the latest business activities and standards, learning to use new tools should already be included in PG&E's authorized revenue requirement. PG&E's inclusion of training expenses as part of PSEP is redundant and should be denied.

Likewise, evaluating new technologies should already be an active business function and also included in PG&E's authorized revenue requirement. PG&E's inclusion of costs related to Detection Technology Assessment as part of PSEP is redundant and should be denied.

DRA also removed GIS/Historian Integration and GIS/Historian Screen Maintenance. Increasing the number of flow meters and automatic valves should not require that PG&E develop a new linkage between its GIS and gas SCADA data systems as PG&E has existing flow meters and automated valves that should already be linked to its GIS and gas SCADA data systems. If the linkage does not exist, then the PSEP filing is an inappropriate proceeding to seek recovery. This type of request would be more appropriately made in PG&E's next GRC application.

After removing the above items from PG&E's proposal, DRA made a proportional adjustment to the remaining maintenance and operational expenses to reflect the decreased valve projects.

(d) DRA does not oppose PG&E's inclusion of Valve Automation Program Development costs as these expenses are funded by PG&E shareholders.

PG&E Valve Automation Program includes development costs of $800,000 to fund the initial planning and filing preparation of the Valve Automation Program, all of which was incurred in 2011.[36]

DRA does not oppose PG&E's inclusion of the development cost as the 2011 expenses will be funded by PG&E shareholders.[37]

B. Interim Safety Enhancement Measures

Ordering Paragraph ("OP")5 of D.11-06-017 directs each utility to include in its Implementation Plan interim safety measures that will apply to specific pipeline segments to increase public safety prior to completion of pressure testing or replacement work. PG&E proposes three interim safety enhancement measures: (1) the Maximum Allowable Operating Pressure ("MAOP") Records Validation Project;[38] (2) interim pressure reductions; and (3) increased leak surveys and patrols.

PG&E's forecasted expenditures for interim safety enhancement measures are tabulated in Table 7-11.

[36] PG&E Prepared Testimony, page 4-65.

[37] PG&E Prepared Testimony, page 4-65, footnote (a) of Table 4-8, and page 8-8 "…PG&E proposes that shareholders will fund the actual 2011 expenses…"

[38] MAOP Project and associated costs are addressed separately in PG&E's and DRA's testimonies.

Table 7-11
Interim Safety Enhancement Measures Expense Forecast
(in million of dollars)

	2011	2012	2013	2014	Total
Interim Pressure Reduction	-	0.7	0.7	0.7	2.1
Leak Survey	-	0.4	0.4	0.4	1.1
Patrols	-	0.0	0.0	0.0	0.1
Total	-	1.1	1.1	1.1	3.2

DRA does not object to the increased leak survey and patrols as OP 5 of D.11-06-017 directed that these be included as part of interim safety enhancement measures. However, DRA disagrees with PG&E on the need for four additional senior gas engineer positions to meet the pressure reduction requirements required by OP 5 of D.11-06-017.

In its Testimony, PG&E states that these gas engineers will perform hydraulic modeling necessary to analyze impacts of pressure reductions and operations necessary to accommodate hydrotesting, in-line inspection, and pipeline replacement.[39] DRA requested workpapers that support PG&E's determination that four full time senior gas engineers are required. PG&E responded that, "No workpapers were developed that support PG&E's determination that four planning engineers are need to meet the extremely large increase in workload for Gas System Planning…."[40] PG&E's response then described the planning engineer workload increases and the increase in work in the Pipeline Safety Enhancement Plan. But pressure reduction requirements under the rulemaking are currently being met and PG&E has not explained why the additional positions are necessary. In various reports that PG&E has filed with the Commission in this proceeding, PG&E's statements illustrate that PG&E is meeting its pressure reduction requirements. For example, PG&E states that it has "completed hydrostatic tests and returned those

[39] PG&E Prepared Testimony, page 6-9.

[40] PG&E data response GasPipelineSafetyOIR_DR_DRA_015-Q01Rev01.

sections to service for 74 test sections and replaced 2 test sections, totaling 102.3 Priority 1 miles."[41] And PG&E "submits this compliance statement to verify that Line 101 short, GCUST7013, has been replaced and pressure tested."[42] And PG&E states: "All pipeline segments operating at or above 20% of specified minimum yield strength (SMYS) on the 101 Lines have been successfully tested to pressures that confirm the safe operation of the 101 Lines at 365 psig."[43]

As shown, PG&E is meeting its current requirement for interim pressure reductions and has not demonstrated why four additional gas engineers are necessary. DRA recommends that the Commission deny PG&E's request.

Table 7-12 compares PG&E's Interim Safety Enhancement Measure request and DRA's recommendation.

Table 7-12
Interim Safety Enhancement Measures - PG&E vs. DRA
(in millions of dollars)

	2011	2012	2013	2014	Total
PG&E Request	0	1.0	1.1	1.1	3.2
DRA Recommendation	0	0.4	0.4	0.4	1.1

C. Program Management Office

PG&E is putting in place a comprehensive management framework to deliver the component projects of the Implementation Plan in a timely, cost effective and high quality manner. The framework includes an Executive Vice President sponsor who is ultimately responsible for the Implementation Plan; an Executive Steering Committee composed of senior level PG&E management personnel representing a cross section of PG&E's business units who are stakeholders in the Implementation Plan; and a full

[41] Report of Pacific Gas and Electric Company on Status of Hydrostatic Pressure Testing as of December 30, 2011, Dec. 30, 2011, page 2.

[42] Pacific Gas and Electric Company's Compliance Statement for Maximum Operating Pressure of Lines 101, 132A and 147. Dec. 15, 2011, page 1.

[43] Pacific Gas and Electric Company's Supplemental Supporting Information For Lifting Operating Pressures Restrictions on Lines 101, 132A, and 147, Dec. 15, 2011, page 1.

time senior level Program Manager who is responsible for the day to day performance of the Implementation Plan. Working for the Program Manager, the PMO provides oversight, ensure quality and control costs.

The PMO will help manage the overall Implementation Plan execution and to coordinate the activities of inter-related projects or work streams. The PMO consists of several sub-teams to perform the necessary tasks to help deliver the program within established time, cost, quality and other defined performance parameters. PG&E's forecasted expenditures for the PMO are shown in Table 7-13.

Table 7-13

PG&E Forecasted Program Management Office
Capital Expenditures and Expense
(in millions of dollars)

	2011	2012	2013	2014	Total
Program Management Office	4.6	10.1	10.1	10	34.8

DRA does not object to PG&E's cost estimate for PMO at this time. DRA considers a strong PMO function that establishes clear goals, scope, responsibilities, reporting requirements, coupled with strong management support a vital requirement for successfully managing this program.

D. Contingency

PG&E includes contingencies of $34.5 million for the Valve Automation Program, $0.9 million for Interim Safety Enhancement Measures, and $6.1 million for the Program Management Office.[44]

DRA's Exhibit 3 analyzes PG&E's contingency request and discusses DRA's recommendations. PG&E's contingency request for the Valve Automation Program, Interim Safety Enhancement Measures, and Program Management Office should be adjusted consistent with DRA's recommendations discussed in Exhibit 3 and the recommendations made in this exhibit.

[44] PG&E Prepared Testimony, page 7-4, Table 7-2.

IV. CONCLUSIONS

DRA recommends that the Commission approve 51 of the 80 valve automation projects to automate existing valves and install new valves that cross active earthquake faults. Other valve projects to install new valves, automate valves in vaults or replace existing valves should be considered in a later phase of the PSEP or PG&E's next GRC application. DRA does not object to PG&E's request related to flow meters and SCADA capital enhancements. Expenses related to SCADA enhancement and maintenance and operations have been adjusted to remove embedded costs that are already included in PG&E's authorized revenue requirement.

DRA does not object to increased leak survey and patrol as part of PG&E's interim safety enhancement measures. However, PG&E has not demonstrated that four additional gas engineering positions are necessary as PG&E is currently meeting its pressure reduction requirements in this proceeding. Finally, DRA does not disagree with PG&E's program management structure and the associated PMO.