PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

GAS TRANSMISSION VALVE AUTOMATION PROGRAM

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CHAPTER 4
GAS TRANSMISSION VALVE AUTOMATION PROGRAM

A. Introduction

The purpose of this chapter is to describe Pacific Gas and Electric Company's (PG&E) Valve Automation Program as part of the Pipeline Safety Enhancement Plan (or Implementation Plan) required by California Public Utilities Commission (CPUC or Commission) Decision 11-06-017. The Valve Automation Program is a critical component of PG&E's plan to modernize its infrastructure and increase public safety. If the Commission approves the Valve Automation Program, the majority of gas transmission pipelines in populated areas in PG&E's service territory, including all of the larger diameter and higher pressure lines, will be able to be quickly isolated in the event of a pipeline rupture, facilitating emergency response and reducing potential threat and impact on the public and property.

The Valve Automation Program will greatly expand PG&E's use of automated pipeline system isolation valves (automated valves). There are two types of automated valves included in the Valve Automation Program, each used for a specific purpose: (1) Remote Control Valves (RCV); and (2) Automatic Shut-off Valves (ASV). PG&E will install RCVs, which are remotely triggered by operators in PG&E's Gas Control Center, in heavily populated areas. Due to the unique threat posed by pipelines crossing earthquake faults, PG&E will install ASVs, 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. 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. All new automated shut-off valves will be capable of operating in RCV or ASV mode, thus enabling PG&E to convert the operation of the valve to a different mode if warranted in the future.

PG&E proposes to prioritize installation of automated valves on pipeline segments based on population density (i.e., class location, presence of High Consequence Areas (HCA), and the Potential Impact Radius (PIR) of the pipeline) and criteria for earthquake fault crossings. In addition, as part of the Valve Automation Program, PG&E will enhance its Supervisory Control and Data Acquisition (SCADA) system to provide the information and tools necessary for operators in its Gas Control Center to better identify and more quickly respond to isolate sections of pipeline if a pipeline rupture occurs. The evaluation of where to add automated pipeline isolation capability, and the determination of the Phase 1 projects and their work scope, was done in close collaboration with EN Engineering (ENE), an engineering firm with extensive knowledge in gas transmission engineering and integrity management.

PG&E is proposing to implement the Valve Automation Program in two phases. This chapter presents the locations identified for Phase 1 implementation (2011-2014), project cost estimates for these installations, and their implementation schedule. In addition, this document provides a preliminary overview for Phase 2 implementation (2015 and beyond). PG&E requests conceptual approval of the overall Valve Automation Program in the Implementation Plan. However, we are only seeking cost recovery for Phase 1 of the Valve Automation Program at this time. The scope, schedule and cost recovery for Phase 2 of the Valve Automation Program, commencing January 1, 2015, will be addressed in a future Commission filing.

1. Valve Automation Proposal

The Valve Automation Program consists of two elements: (1) installation of automated valves; and (2) SCADA system enhancements.

a. Installation of Automated Valves

The objective of the Valve Automation Program is to enable PG&E to either remotely, or with local automatic control, quickly shut off the flow of gas in response to a gas pipeline rupture. Under the design criteria for the program, automated valves are spaced so that in the event of a full pipeline rupture, pressure in the pipe will dissipate in minutes following valve closure. The Valve Automation Program will also replace valves where needed to assure “piggability” in the pipeline system.

The objective of the Valve Automation Program is to significantly shorten the time required to isolate and blowdown[1] pipe segments containing large quantities of high pressure natural gas in populated areas in the event a pipeline rupture occurs. The key benefit of this reduction in response time is to enable first responders to mobilize and quickly take action to address the rupture event and its consequences.

The target of the Valve Automation Program is the retrofit of existing gas transmission pipelines. However, PG&E will also evaluate all new pipeline projects and replacement pipeline projects for valve automation based upon the decision-making criteria in this program, plus the following additional criteria: (1) all future projects will be evaluated for valve automation based upon anticipated future class location; and (2) pipe projects for existing Class 1 and 2 HCAs will automate manual valves required by these projects based upon the more inclusive Class 3 valve automation criteria. This acknowledges the fact that automation can be accomplished at lower incremental cost at the time of new pipeline installation, and achieves the greatest amount of safety value for the capital expenditures.

The Valve Automation Program will be implemented in a phased approach. During Phase 1 (2011-2014), PG&E will replace, automate and upgrade 228 isolation valves. The Valve Automation Program "launch" will commence in 2011 with 20 new automated valve installations on the San Francisco Peninsula from Milpitas to San Francisco. At completion of Phase 1, the Valve Automation Program will result in approximately 410 miles of gas transmission pipeline in Class 3 and 4 areas being equipped with automated isolation valves, typically at 5-8 mile intervals, and automatic shut-off valves being installed on 9 pipe segments traversing 16 active earthquake fault crossings. Phase 2 will include the automation of roughly 330 additional valves.

Phase 1 will focus on pipelines in Class 4 areas, and larger diameter, higher pressure pipelines located in highly populated Class 3

[1] "Blowdown" is the process where gas in the pipeline is evacuated until the gas pressure reaches atmospheric pressure.

areas. The following map highlights the core area of Phase 1 work. Approximately 60 percent of the Phase 1 automation miles are located in the Peninsula, South East Bay and South Bay. Other significant areas of work include pipelines in and around Sacramento, Stockton, Fairfield, Bakersfield and Morgan Hill, and the Highway 4 corridor between Antioch and Highway 80 in the East Bay. All sites identified by symbols (i.e., circles, squares and triangles) in Figure 4-1 are locations where specific types of valve automation work will be implemented as part of Phase 1. A larger scale map of this area is provided as Attachment 4A.

FIGURE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
MAP OF PHASE 1 VALVE AUTOMATION

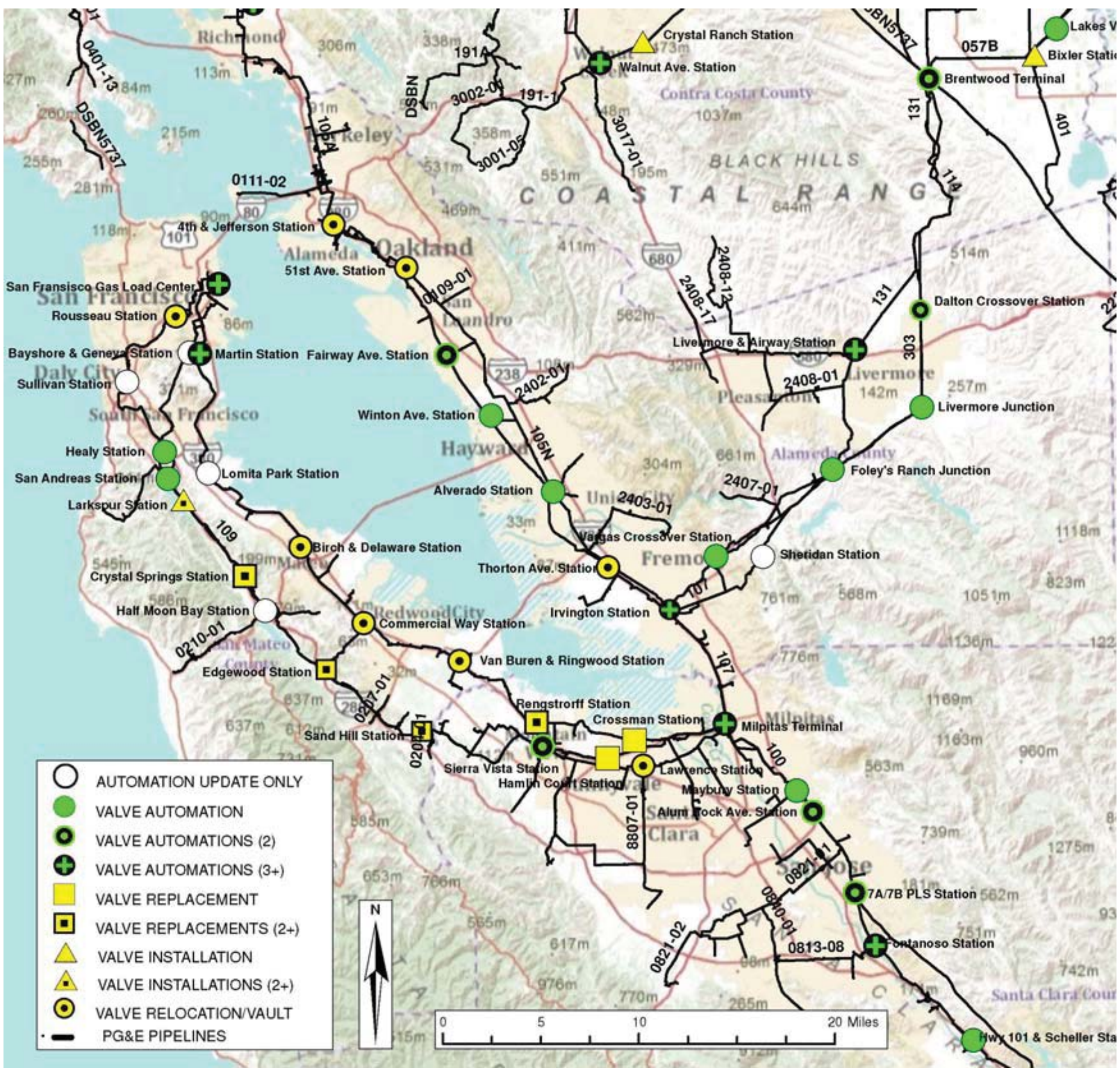
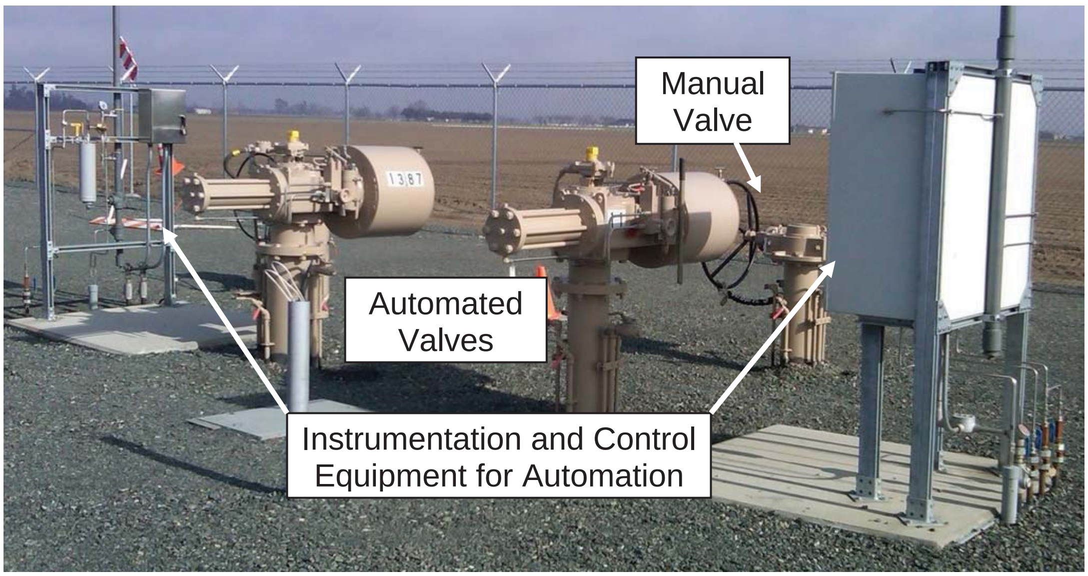


Figure 4-2 illustrates a typical pipeline station facility containing both manual and automated valves. The photo shows two automated and one manual valve, and the instrumentation and controls for the automated valves.

FIGURE 4-2
PACIFIC GAS AND ELECTRIC COMPANY
PHOTO OF AUTOMATED VALVES



Automated valves have equipment that provide for the valve to be opened and closed without a person having to physically be at the valve site. To automate an existing manual valve, the manual gear operator must be removed and replaced by equipment (i.e., valve actuator and controls) that provides for automated operation. Not all existing valves can be automated due to their type or how they were originally installed. In these cases, the valve needs to be replaced prior to being automated.

All valves being installed by the Valve Automation Program have both RCV and ASV capability. Valves termed as RCVs have the ASV functionality disabled due to risks discussed in Section B.3.b of this Chapter, “RCV vs. ASV Usage Determination.” ASVs are valves that have both RCV and ASV functionality enabled.

b. SCADA System Enhancements

Automated valves provide a mechanism for quickly isolating pipeline segments in the event of a rupture, but this capability can only be fully leveraged if Gas Control operators have the proper control systems and training programs in place to monitor the system, quickly assess abnormal and emergency conditions, and take appropriate actions in response to an incident. The Valve Automation Program includes development and deployment of systems and technologies to provide early warning of events, while preventing false valve closures. To ensure proper use of the RCV/ASVs, PG&E will provide Gas Control operators with additional information, tools, and training to allow for early detection and quick response to pipeline rupture events. These will include:

1. Additional SCADA monitoring points for pressures and flows to enhance understanding of pipeline dynamics.
2. Detailed SCADA viewing tools that provide a comprehensive understanding of individual pipeline conditions in real-time and the potential effects (e.g., downstream pressures and flows) if a pipeline segment is isolated, as well as provide increased understanding of pipeline configuration and constraints.
3. Specific pipeline segment shutdown protocols to provide clear instructions on actions to be taken to quickly and effectively isolate a segment.
4. Situational awareness tools, which utilize advanced composite alarming, and best practice alarm management methodology to highlight issues requiring immediate Gas Operator action.
5. Interactive tools that will allow Gas Operators to quickly access GIS physical pipeline information in relationship to SCADA points, and to geographically locate SCADA points.
6. Training simulation tools to prepare Gas Operators for potential pipeline rupture scenarios.

In addition, to ensure effective execution of these actions, and to identify additional SCADA improvement opportunities, PG&E will act upon the suggestion in the Independent Review Panel (IRP) Report[2] to have an external party review PG&E's gas SCADA system coupled

[2] The IRP Report dated June 8, 2011 was revised on June 24, 2011.

with a best practices review of SCADA systems and their usage within other gas pipeline companies and related industries. This will include an evaluation of whether the installation of additional SCADA monitoring points above what is already proposed is warranted. PG&E will continually assess the effectiveness of its SCADA and control systems, including the new tools and system modifications listed above. Continuous improvements will be made to the tools and information to ensure that controllers are able to make the best informed operating decisions.

c. Valve Automation Program Cost Request

PG&E requests that the CPUC adopt PG&E's 2011-2014 (Phase 1) Valve Automation Program capital expenditure and expense forecasts, as shown in Table 4-1 below, as reasonable.

TABLE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM REQUEST
$ IN MILLIONS (NOMINAL)

Line No.	Work Description – MAT Code	2011(a)	2012	2013	2014	Total
1	Capital Expenditure Request					
2	Valve Automation – 2H3	$13.6	$33.4	$43.2	$22.5	$112.7
3	Valve Automation-StanPAC – 44A	–	2.0	4.6	–	6.6
4	Flow Meter Installations – 2H3	–	3.9	5.3	3.3	12.5
5	SCADA Enhancements – 2H3	0.1	0.2	0.2	0.2	0.7
6	Valve Automation – Total Capital Expenditures	$13.7	$39.5	$53.3	$26.0	$132.5
7	Expense Request					
8	SCADA Enhancements – KE4	$0.8	$1.8	$1.8	$2.2	$6.6
9	Reoccurring Operations and Maintenance – KE4	–	0.8	1.3	1.6	3.7
10	Program Planning and Development – KEX	0.8	–	–	–	0.8
11	Valve Automation – Total Expenses	$1.6	$2.6	$3.1	$3.8	$11.1
12	Valve Automation Total (Capital and Expense)	$15.3	$42.1	$56.4	$29.8	$143.6

(a) The 2011 expenses and capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

B. Valve Automation Program

1. Scope of Valve Automation Program

PG&E has selected the pipelines and pipe segments for automated isolation capability where automated isolation will have the greatest impact on minimizing risk related to a pipeline rupture event.

Automated valves do not have any ability to prevent a rupture event from occurring or to minimize the consequences from the initial burst of energy following a pipeline rupture. However, risk mitigation will occur by quickly isolating and stopping the flow of gas to the atmosphere following a rupture event. The focus of the Valve Automation Program is on the potential benefits to the public and emergency responders, particularly those related to minimizing property damage, which can be achieved by a quick isolation of the natural gas fuel source.

Risk is a mathematical product of the likelihood or probability of an event occurring and the consequences or results should the event occur. The probability and consequence of an extended duration natural gas fire from a pipeline rupture are made up of various components.

The **probability** of the event occurring is a function of the likelihood of:

- A pipe failure.
- The failure results in the pipe rupturing.
- The released gas at the rupture site ignites.

The **consequence** of the event is a function of:

- The population density and type of structures and infrastructure in the surrounding area.
- The intensity of the ignited flame at the rupture location.[3]
- The time required to isolate and blow down the pipe segment.

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[3] The potential for the gas released during a rupture event to ignite is not a controllable parameter, and is therefore not addressed in any aspect of PG&E's Implementation Plan. Ignition probability for a pipeline rupture is greater in populated areas where there are more ignition sources. The probability of ignition is estimated to be approximately 30 percent for a highly populated area. Ignition probability based upon EN Engineering Technical Paper, "Ignition Probability for Natural Gas Pipelines", dated January 21, 2008.

- The combustible fire threat in the area and the ability of emergency resources to respond to the fire.

The Pipeline Modernization Program portion of the Implementation Plan, described in Chapter 3, is focused on minimizing the probability of a pipe failure. The Pipeline Modernization Program places a priority on older vintage pipes in populated areas.

The Valve Automation Program works in tandem with the Pipeline Modernization Program by having as its primary focus those areas where the potential consequences are greatest, and on those pipelines which—given a rupture and gas ignition—would create the highest intensity flame. Additionally, the Valve Automation Program puts an emphasis on automatic isolation of pipe segments that cross active earthquake faults to mitigate potential consequences at those locations that are at the highest risk of pipe failure in an earthquake event. The SCADA enhancements portion of the Valve Automation Program also addresses consequence by enhancing identification and decision making and shortening the time required to isolate a pipeline segment after a pipeline rupture.

2. Pipe Segment Selection for Automation

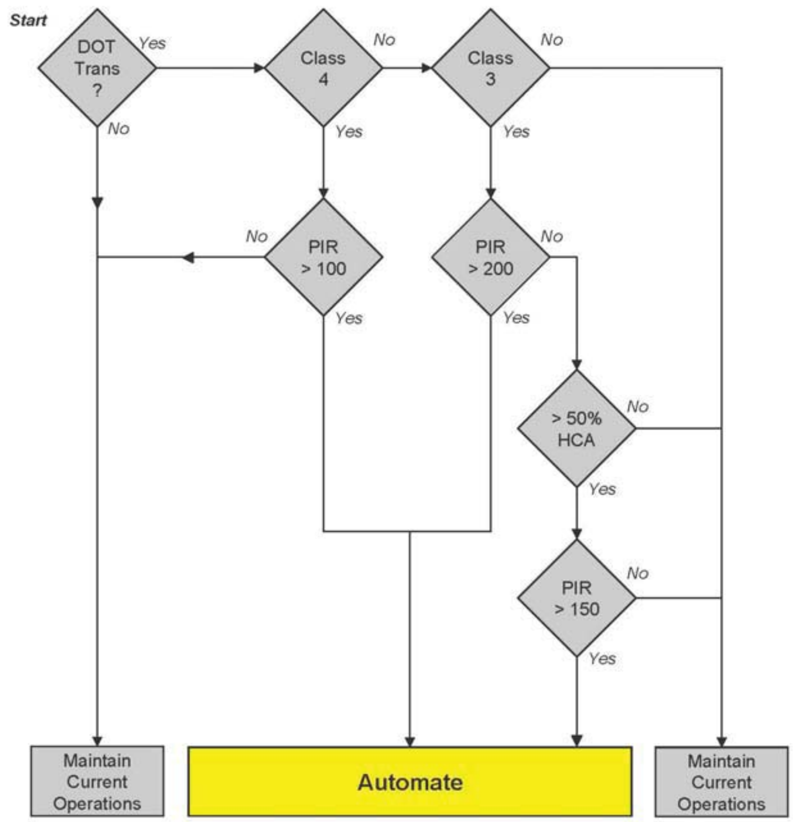
PG&E has created two decision trees, one based on population density and the other based on earthquake fault crossings, to assist the Company's engineers in determining which pipe segments should be equipped with automated isolation capability as part of the full Valve Automation Program (Phases 1 and 2). In order to mitigate consequences in the event of a pipeline rupture, PG&E recommends installing automated pipeline isolation capability on Department of Transportation (DOT) defined gas transmission pipeline segments within Class 3 and 4 areas that exceed minimum threshold criteria for pipe size and operating pressure as defined using a PIR calculation. For higher populated areas (i.e., Class 3 HCA and Class 4 areas), the minimum threshold criteria are reduced to recognize the higher potential consequence.

In addition, PG&E recommends installing a higher level of automated isolation on certain pipeline earthquake fault crossings in populated areas. These would be DOT defined gas transmission pipelines within Class 3 and 4 areas and Class 1 and 2 HCAs that exceed minimum threshold criteria for pipe size and operating pressure, and cross active faults that have a significant probability of rupturing a pipeline under maximum anticipated seismic event conditions. Active earthquake faults are defined per the Alquist-Priolo Fault Zoning Act. A more detailed description is provided in Section 2.d.(2) below.

a. Decision Trees

Figure 4-3 is the decision tree that evaluates high population density and Figure 4-4 is the decision tree that evaluates earthquake fault crossings. Section B.2.b., below, includes a detailed description of the key factors in segment selection including the logic and reasoning behind the development of the decision trees and their specific components. The decision trees were a key tool in determining pipe segments to be automated, but their use was always combined with practical engineering judgment.

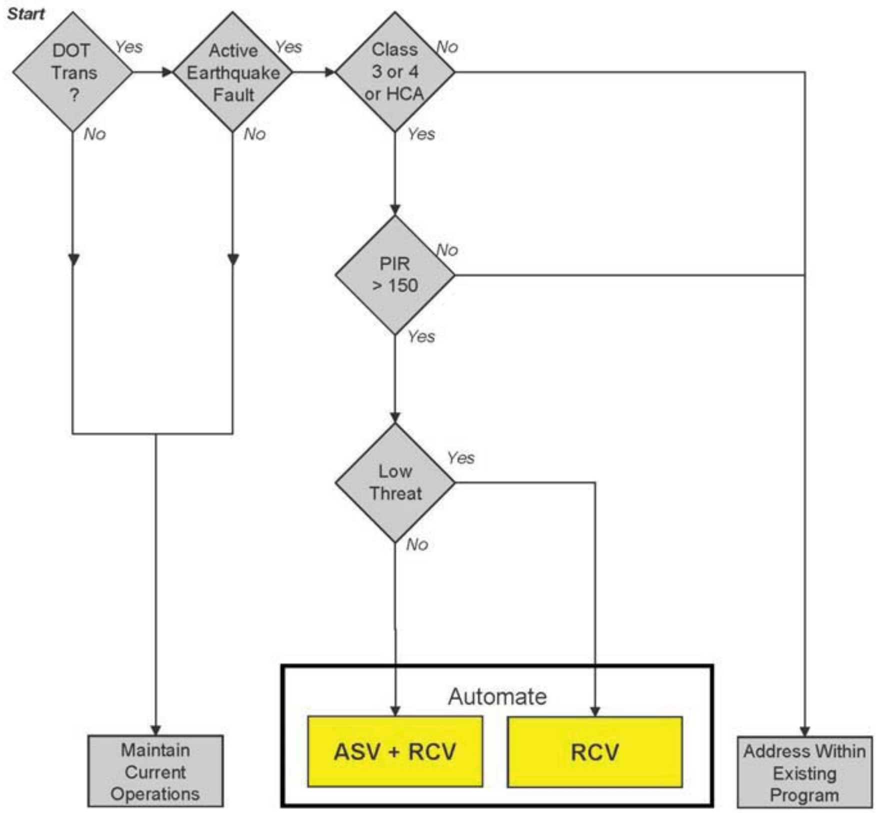
FIGURE 4-3
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – POPULATION DENSITY



Note: All PG&E Class 4 pipe segments classified as gas transmission have a PIR value greater than 100 feet, therefore all Class 4 pipe segments are identified for automation.

The Population Density Decision Tree is utilized to identify all Phase 1 and Phase 2 pipe segments that will be automated. Phase 1 scope is focused on all Class 4 identified segments and Class 3, PIR > 300 feet, segments that are in areas that have a predominance of HCA.

FIGURE 4-4
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – EARTHQUAKE FAULT CROSSING



Within the "Automate" box of the Earthquake Fault Crossing Decision Tree are two alternatives. Where fault crossings were deemed a significant or high threat to the pipeline, ASVs will be installed, which also have RCV capability. PG&E defines Low Threat in Section 2.d(3) below. These valves will closely bracket the fault. Where only a low threat exists, the fault crossing will be able to be isolated with RCVs installed at the same general spacing as for valves equipped with RCVs in the Population Density Decision Tree.

b. Key Factors in Segment Selection

(1) DOT Defined Gas Transmission Pipe

All pipe within PG&E's gas system with an operating stress level that exceeds 20 percent Specified Minimum Yield Strength is classified as DOT defined gas transmission pipe (49 Code of Federal Regulations (CFR), Section 192.3). All 16-inch and larger pipelines within PG&E's system operating at a pressure above

240 pounds per square inch gauge (psig) are classified as DOT gas transmission. This represents inclusive criteria to use as a starting point when evaluating where to install automated valves.

(2) Population Density – Class 3 and 4 Locations and HCAs

The value of automated valves to isolate pipe segments in an emergency is greatest in heavily populated, urban environments. Heavily populated areas represent access issues to emergency response personnel fighting a fire and represent the areas where fires would result in greatest safety risks and the largest property damage costs.

The federal code governing pipeline safety uses two different means of identifying more heavily populated areas: (1) class location (49 CFR 192.5); and (2) HCAs (49 CFR 192.903). A class location unit is an area 220 yards on either side of the centerline of any continuous 1-mile length of the pipeline. Class 4 is 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 greater than a certain amount of time. Class 2 and 1 locations are the least densely populated areas with 10-45 buildings and less than 10 buildings within a class location unit, respectively.

The definition for HCA utilized by PG&E is an area within a potential impact circle containing: (a) 20 or more buildings intended for human occupancy or (b) an "identified site." Potential impact circle is a circle around a point on the pipeline with a radius equal to the PIR of the pipe at that location. An "identified site" is a location where 20 or more people gather above a certain frequency or facilities occupied by persons who would be difficult to evacuate (e.g., nursing homes). A multi-mile continuous length of Class 3 HCA pipeline is generally significantly more heavily populated than a Class 3 non-HCA area.

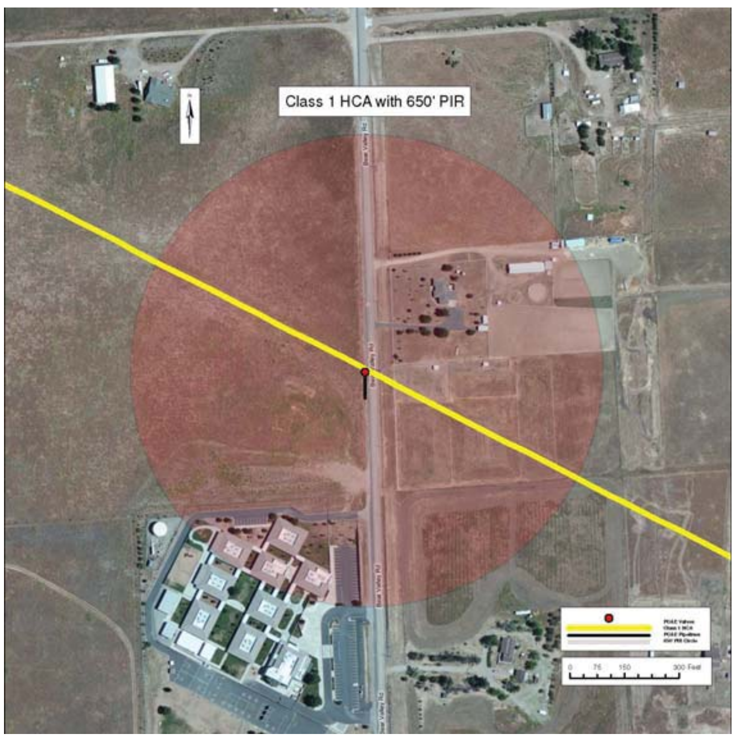
Class 3 and 4 areas capture all heavily populated areas within PG&E's service territory, with the vast majority of pipe within this classification occurring within the greater Bay Area. A total of 1,725 miles, approximately 30 percent, of PG&E's gas transmission pipe is located in Class 3 and 4 areas. Within Class 3 and 4 areas, PG&E has 947 miles of HCA pipe.

The following photo provides visual representation of a typical Class 3 HCA area.

FIGURE 4-5
PACIFIC GAS AND ELECTRIC COMPANY
CLASS 3 HCA EXAMPLE

HCA areas outside of Class 3 and 4 areas are typically localized areas of population within rural environments. They only span short segments of pipeline, typically less than one mile segments, so these have been excluded from the pipeline automated isolation program scope, except for earthquake fault crossings. Because of the nature of these segments within PG&E's gas transmission system, the typical cost per mile required to automate HCA pipe in Class 1 and 2 locations would be approximately six to eight times the cost per mile of Class 3 pipe slated for automation in Phase 1 of the Valve Automation Program. The increased cost per mile is primarily due to the very short lengths of the pipe segments requiring automation (the cost of providing automated isolation capability for an identified segment is independent of its length) and the need to install additional valves for closer spacing intervals. The following photo provides a visual representation of this localized risk.

FIGURE 4-6
PACIFIC GAS AND ELECTRIC COMPANY
CLASS 1 HCA EXAMPLE



(3) Potential Impact Radius

"Potential Impact Radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property" (49 CFR 192.903, subpart 4.c). PIR is a function of the pipe diameter and the pressure of the natural gas in the pipe, and is proportional to the heat intensity of the initial flame should a pipeline rupture ignite. The following table defines the required operating pressures for various diameters of pipelines to have a specific impact radius.[4]

TABLE 4-2
PACIFIC GAS AND ELECTRIC COMPANY
OPERATING PRESSURES FOR VARIOUS PIPE SIZES AND PIR VALUES

Line No.	Pipe OD (Inches)	PIR=	100’	150’	200’	250’	300’
			Pressure (psig)				
1	6.625		479	1077	1914	2991	4307
2	8.625		282	635	1129	1765	2541
3	10.750		182	409	727	1136	1636
4	12.750		129	291	517	808	1163
5	16.000		82	185	328	513	738
6	20.000		53	118	210	328	473
7	24.000		36	82	146	228	328
8	30.000		23	53	93	146	210
9	36.000		16	36	65	101	146

The higher the PIR value, the greater the impact of the ignited rupture on the ability of emergency response personnel to fight and contain the fire, and the greater the risk if the natural gas fuel source is not shut-off quickly. The program scope threshold for pipe size and operating pressure is defined using PIR value.

c. Pipelines in High Population Density Areas

The Company will install automated pipeline isolation capability on all DOT defined gas transmission pipelines within Class 3 and 4 areas where the:

(1) PIR > 200 feet for pipe segments located in Class 3 areas.

(2) PIR > 150 feet for pipe segments located in areas with a predominance of Class 3 HCA.

(3) PIR >100 feet for pipe segments located in Class 4 areas.

For PG&E’s gas transmission pipelines in Class 3 areas, a PIR > 200 feet would generally translate to automated valves being installed on 12-inch and larger diameter pipelines. Within Class 3 and 4 areas, PG&E has 774 miles of pipe with a PIR that exceeds 200 feet, of

[4] The equation for calculating PIR is defined in 49 CFR 192.903, subpart 4.c, and is: PIR (feet) = 0.69 x D x √P, where, D = Pipe outside diameter in inches, and P = Maximum Allowable Operating Pressure (MAOP) for the pipeline containing the pipe segment in psig.

which 572 miles or nearly 75 percent are also in HCAs. There is an additional 153 miles of Class 3 HCA pipe with a PIR between 150 feet and 200 feet.

The base PIR threshold value for Class 3 locations of 200 feet corresponds to a PIR value at which the flame from an ignited pipeline rupture is not anticipated to hinder emergency responder efforts in containing the fire. The value of 200 feet was determined by a fire hazard analysis completed by a third-party consultant with expertise in fire protection and risk analysis. A key fact worth noting is that 15 minutes after the rupture, the heat intensity has significantly decreased due to the reduction in natural gas mass release rate at the rupture site. The heat intensity at 15 minutes corresponds to a radius of approximately 60 percent of the initial PIR value.

The lower PIR values of 150 feet and 100 feet for Class 3 HCA and Class 4 areas, respectively, were based upon a greater potential for emergency response issues associated with a rupture as the population density increases and the likely increased risk to public safety and property. For example, pipe in the PIR range of 150-200 feet would have to be located in at least a fairly dense residential neighborhood of detached single family homes to be classified as being in an HCA based upon population density. This level of congestion increases the complexity of search and evacuation efforts for first responders and the complexity of firefighting efforts, resulting in PG&E’s conservative recommendation to automate these pipelines.

For PIR values below 150 feet for Class 3 HCAs and 100 feet in Class 4 areas, firefighting efforts should have the capability to shoot water directly onto an ignited natural gas flame, minimizing the effects of heat from the fire and potential fire damage. These pipes pose significantly fewer firefighting issues. Also, over 70 percent of pipe operating over 60 psig in PG&E’s gas system with a PIR value of 100 feet or less falls under the DOT classification of gas distribution pipe.

d. Pipelines in Active Earthquake Fault Zones

(1) Earthquake Fault Automation Plan Overview

PG&E recommends installing automatic control valves on larger diameter, higher pressure transmission line segments crossing active earthquake faults in urban areas when the segment has a significant risk of rupture during a maximum magnitude earthquake event. Northern California is an area of high seismic activity. PG&E pipelines traverse 170 active earthquake fault crossings, of which 46 are in Class 3, Class 4 or HCA areas. These locations represent some of the largest location specific risks to a pipeline. In addition, a major earthquake in an urban area would severely strain emergency response resources, thus further increasing the potential consequences from an earthquake induced rupture. For the seismic crossing aspect of the project, PG&E proposes to install valves within approximately one mile of each side of the fault line. Pipeline segments that have already been designed or reinforced to withstand the maximum projected fault movement without rupturing were excluded from the ASV scope. Because active earthquake faults are a location (point) specific risk, pipeline fault crossings in Class 1 and 2 HCA areas (which are very localized areas) were also included in the pipeline earthquake fault crossing assessment, in addition to Class 3 and 4 areas.

PG&E will install automated pipeline isolation capability on all pipeline earthquake fault crossings in Class 3 and 4 areas, and Class 1 and 2 HCA areas where:

- The pipe has a PIR value of > 150 feet.
- The earthquake faults are considered active.
- The pipe has greater than a low threat of rupture under maximum anticipated magnitude event conditions.

For pipelines crossing earthquake faults in sparsely populated areas, a significant consequence of a pipeline rupture is loss of gas service to downstream customers. The value of automated valves in effectively addressing this consequence has to be evaluated on a case-by-case basis. These crossings are included in PG&E's Gas Transmission Pipeline Enhancement Program (discussed in more detail below) and are not part of the Valve Automation Program.

(2) Active Fault

With the exception of a few rare examples, in tectonically active regions, surface faulting occurs on existing faults that: (1) have been the source of historical surface faulting; (2) are undergoing active creep; or (3) have experienced surface faulting within the past 11,000 years (Holocene). The Alquist-Priolo Earthquake Fault Zone Act (Act) was established by the California Legislature in 1972 to mitigate the potential hazards of surface rupture associated with seismic activity. The Act requires the California Geological Survey to evaluate and delineate active faults throughout the state. A fault or fault zone is considered active under the provisions of the Act if there is evidence of surface displacement within Holocene time. For evaluation of potential automated valve locations for pipe segments crossing earthquake faults, active faults are defined as those identified as "Historical" or "Holocene" in PG&E's Geographic Information System (GIS) database, which includes the faults meeting the criteria described in the first part of this paragraph.

(3) Threat of Rupture

The threat of rupture is determined by the potential magnitude and likely frequency of a major earthquake event, and the susceptibility of the pipe segment to rupture during a major event. PG&E has developed a list of all transmission pipelines crossing active earthquake faults. In this database, the earthquake fault slip rate and the probability of a 6.7 or greater magnitude earthquake occurring within the next 30 years are determined for each segment. These two characteristics are typically related to one another. For earthquake faults with a slip rate in the lowest category of 0.2-1 millimeters per year, the corresponding probability of a major event occurring is approximately two (2) percent over 30 years. PG&E has defined this category of earthquake fault as being low threat. In those cases where PG&E has already implemented design mitigation measures to prevent a rupture based upon predicted magnitude earthquake events, these faults are also deemed as low threat.

(4) Gas Transmission Pipeline Enhancement Program

After the 1989 Loma Prieta earthquake, PG&E performed a system wide (Gas Supply and Gas Distribution Business Units) earthquake vulnerabilities review. This was done to identify opportunities to reduce earthquake vulnerability by mitigating the potential weak points, such as pipeline earthquake fault crossings, pipe supports for above ground piping and pipe spans, and equipment in control rooms and stations. The studies found that gas transmission pipelines and facilities are generally resistant to earthquake damage and are expected to be operational following earthquakes. This finding was consistent with previous experience with modern gas pipeline systems struck by earthquakes in California, such as Loma Prieta, Humboldt and Landers events, and in other parts of the world, such as the Taiwan Ji Ji Earthquake and Kobe Earthquake. The most significant vulnerabilities were found at above-ground facilities involving anchorage and bracing components at control rooms and stations, which have since had these vulnerabilities mitigated. The remaining vulnerable locations are fault crossings. Since buried pipelines are expected to perform reasonably well in an earthquake event, they were not extensively assessed during the original studies.

PG&E followed up the work that began after Loma Prieta with the Gas Transmission Pipeline Enhancement Program, which reviewed all gas transmission line fault crossings. Several fault crossings have been replaced since 1994. Under this existing program, PG&E reviews whether the risk of rupture due to an earthquake can be mitigated by design, i.e., the pipeline segment crossing the fault is re-designed to withstand the maximum displacement expected from a fault rupture. This is a different and complementary mitigative measure to installing automated valves. In 2008, a list of all gas transmission pipeline fault crossings and a multi-year plan of mitigations was developed and documented in PG&E's RMP-04 "Ground Movement and Natural Forces Threat Algorithm." There were a total of 170 fault crossings identified, 46 of which are in Class 3 or HCA areas. No crossings are in Class 4 areas. To date, 9 crossings in Class 3 areas, and 15 crossings in total, have been mitigated by design. Of the remaining 37 fault crossings in Class 3 or HCA areas, 17 are categorized as low threat (i.e., have a PIR < 150 feet or have a low probability of rupture), 16 will be automated with ASVs, and the other four (4) will be fully mitigated by pipeline design. The ASV and pipeline design mitigation work is planned to be completed by the end of 2014. Examples of the types of design mitigation measures implemented include: the use of thicker wall and more ductile pipe material, the use of V-trench and light weight backfill to allow movement of the pipe in an earthquake, the addition of geo-fabric wrap to reduce friction between pipe and soil, and the realigning the pipeline so it crosses the fault at a lower risk angle.

3. Design Details of Pipe Segment Automation

Once PG&E identified which segments of pipe will have automated isolation capability, we then had to decide the optimal valve spacing requirements for isolation, whether ASVs or RCVs will be used, define the work scope required to provide complete isolation of a segment, and define the specific design requirements for each site requiring modification.

a. Valve Spacing Determination

The valve spacing will affect the time it takes to evacuate gas from a ruptured pipe segment after the isolation valves are closed. Valve spacing will also affect the magnitude of the customer continuity of service issues that will result from valve closures that take a pipeline segment out of service.

49 CFR, Section 192.179(a), provides guidance for the installation of isolation valves (i.e., sectionalizing block valves). Although this is not applicable specifically to automated valves, it is a good starting point for a maximum spacing guideline since it was developed taking into account

typical operational impacts of pipelines in various class locations. The code requires:

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

(1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve.

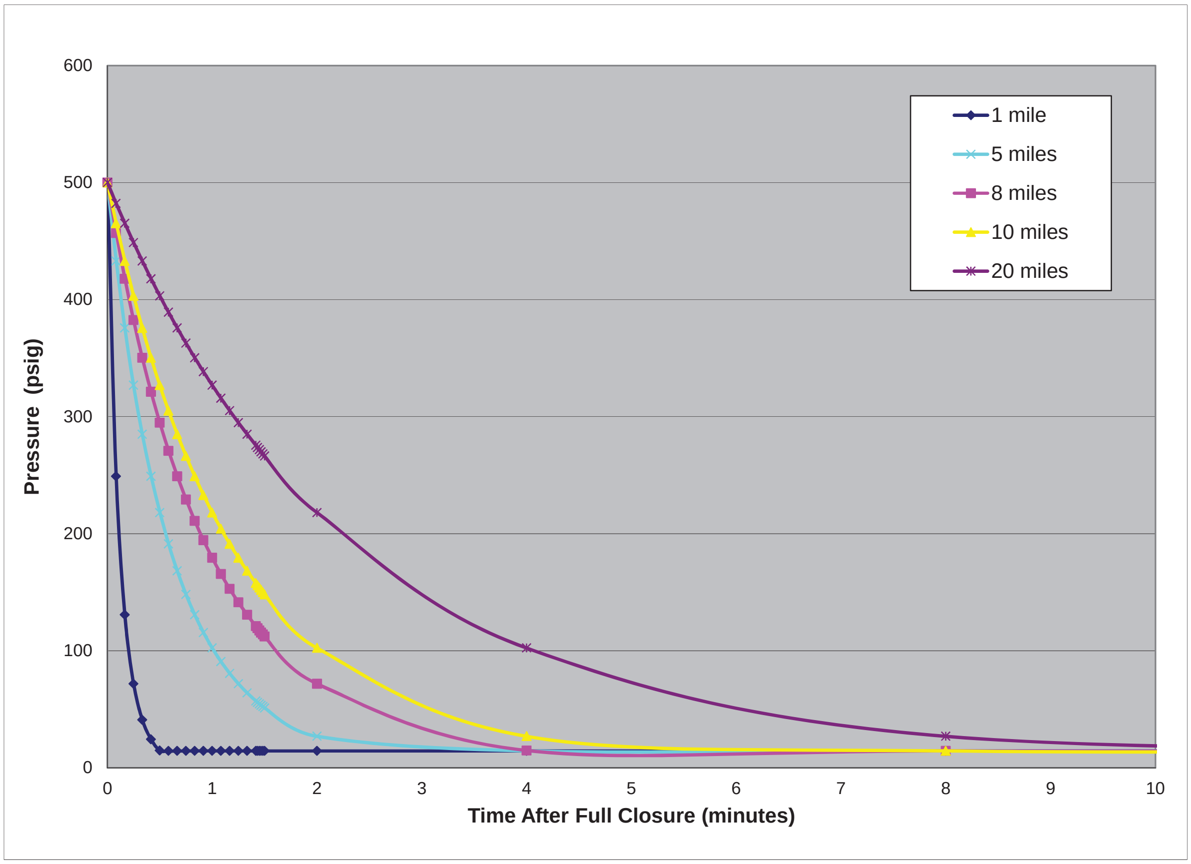
(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

To further evaluate maximum valve spacing impacts, PG&E hired a pipeline engineering contractor to analyze the effects that various valve spacings would have on the time to evacuate a pipe section after it had been isolated for a full pipeline rupture event. The results found that if the valve spacing was limited to the Class 3 requirement of eight miles, the blowdown time has only minor impact on the overall time required to isolate a pipe section using RCVs and minimal impact on facilitating emergency response.

Eight mile spacing adds only approximately two minutes to the valve blowdown time for a full line break situation, in comparison to five mile spacing. A full line break with eight mile spacing with a pipeline starting pressure of 1,000 psig is estimated to blowdown in five minutes. Based upon this, an approximate maximum spacing of eight miles was used in determining automated valve locations for Class 3 locations. As a conservative measure, and to stay aligned with the code guidance, an approximate five mile valve spacing was utilized for the higher impact Class 4 areas. In either case, the maximum distance was allowed to be slightly exceeded, to permit a valve to be automated in a more accessible or lower public impact area.

Figure 4-7 illustrates the blowdown times for a full pipeline rupture situation for a pipeline that is operating at 500 psig at the time of rupture. It is important to note that this table is for a full line break situation; for a partial line break or pipeline leak it would take much longer to evacuate the gas, but the natural gas release rate and impact radius would be much less as well.

FIGURE 4-7
PACIFIC GAS AND ELECTRIC COMPANY
BLOWDOWN TIMES VS. VALVE SPACING FOR FULL PIPELINE RUPTURES



The actual valve spacing PG&E chose for the Valve Automation Program was often times less than the maximum valve spacing guideline discussed previously, based upon the potential number and criticality of customers that could lose service if a specific pipe segment was taken out of service. As a general rule of thumb, valve spacing distances were chosen that limited the potential number of customers being fed off of a pipe segment to no more than 50,000.

In addition, where automatic valves are being recommended at earthquake fault crossings, the spacing was reduced to more closely bracket the threat. This closer spacing also minimizes the number of customers within a fault crossing isolation segment, and any potential loss of service to customers if an inadvertent valve closure occurs.

b. RCV vs. ASV Usage Determination

There are two types of automated valves that can be utilized for isolation of pipe segments. RCVs are valves that can be closed via the SCADA system by a remote operator located at a Gas Control Center. ASVs are valves that are closed automatically based upon the local control system at the valve site detecting a line rupture or any other condition that the controls are programmed to trigger a valve closure. PG&E analyzed the different risks and benefits associated with these two systems to provide optimal automation for specific situations in developing its Valve Automation Program.

(1) Remote Controlled Valves

RCVs rely upon the remote operator reviewing all available data to determine if valve closure is warranted. By understanding the current system conditions and configuration, and by being able to evaluate the pressure and flow data at multiple sites, an operator would be able to assess a multitude of factors into the decision to isolate a section of pipeline by remotely closing valves. Valve controls would be designed for the valve to fail in its last position if it lost communication or power to limit the opportunity for a valve to change position without human intervention. This makes it very unlikely that an inadvertent or false valve closure will occur.

Because RCVs require human decision-making to close a valve, they will not typically react as quickly to a rupture situation as ASVs. PG&E anticipates that RCVs installed and utilized for full line rupture isolation will typically allow for a pipe segment to be isolated and blown down to near atmospheric pressure within 30 minutes, while an ASV would accomplish this in under 15 minutes if it identified a pipeline rupture condition. For an RCV to be functional, it requires the gas SCADA system and communication path to be operational. Because PG&E gas SCADA communications typically use dedicated lease line or a PG&E-owned microwave radio system, it is very likely they will be available and operational after a major earthquake event, although this is an operational risk of RCVs.

(2) Automatic Shut-off Valves

The greatest concern associated with ASVs is the risk of a false or inadvertent closure of the valve. This is due to the fact that the complexity of controls to accurately detect a rupture in a multi-mile stretch of pipeline is challenging, especially in situations where there are interconnected pipeline facilities. Because ASVs are most often closed based upon low pressure or rate of rapid pressure decline, the likelihood of a false closure is greatest when system flow demands are the highest and at points closest to large system loads where there would be less time to react to a false closure. A false closure could create customer outages and threaten PG&E's ability to maintain continuity of service to customers.

ASVs require complex control systems. If the control systems fail to function properly, there is the risk that the ASV controls will fail to identify a pipeline rupture when one does occur, or that the ASV controls could cause a cascade effect and isolate multiple pipeline sections in addition to a section containing a pipeline rupture. These concerns have been identified in industry studies that reviewed the use of automatic controls to isolate a pipeline segment.

Based upon the risks and benefits, PG&E plans to design automated valves to be capable of both remote control and automatic control, but to only initially enable the automatic control capability for a small number of situations. The primary use of the automatic control function would be where automated valves are installed to isolate a pipeline segment at certain earthquake fault crossings. At these locations, the valves would be installed in close vicinity to the fault, thereby providing quicker and more reliable pipeline rupture detection capability. PG&E would track and evaluate the potential automatic control parameters, primarily pressure and rate of pressure change, at RCV sites to further evaluate the risk of a false closure and determine if expanded use of automatic control is warranted in the future.

(3) Continuity of Service Impact

Since maintaining continuity of service to customers was a key identified risk of using automatic controls, and in making the choice between RCVs and ASVs, this section provides some additional detail of the safety risks associated with a breakage in service continuity. Restoration of gas service, depending on the scope of an incident, may take several days or weeks. A loss of gas service during the winter season may result in customers trying to relight appliances themselves rather than waiting for qualified gas personnel to safely restore service. Some customers have used unsafe methods to heat their homes by using barbeques or propane appliances, resulting in carbon monoxide poisoning. Additionally, an interruption in service can pose health risks to sick, elderly and disabled customers. A partial loss of pressure in a gas distribution system due to loss of a transmission supply source may result in a pressure drop, causing pilots on customer equipment to extinguish. Subsequent repressurization of the system without appropriate safety measures and procedures can result in the potential of gas escaping into structures and posing a risk of explosion.

C. Scope of SCADA Enhancements

If a pipeline leak or rupture occurs, there are several steps that determine the overall response time to isolate and depressurize a pipeline segment. The automation of pipeline isolation valves provides the capability for these valves to be closed quickly once a determination has been made to isolate. Prior to isolation, however, the leak or rupture has to be detected and the decision made to isolate a pipeline segment. The SCADA enhancements described in this section address these two steps. These enhancements fall into three categories:

- Additional information relating to pressure, flows and other critical gas system data within the SCADA system that will enhance controllers' knowledge of gas system conditions and support early detection of, and better understanding and pin pointing of, an excursion from anticipated conditions.

- Additional training for operators in detection of events and proper response to specific events.
- Advanced SCADA logic, tools and technologies that identify abnormalities and bring them to the attention of the operator.

The Valve Automation Program includes the following Phase 1 actions as part of each of these three categories of work.

Additional enhancements to improve the information and tools used for decision making:

- Providing pressure measurement upstream and downstream of all automated valves, and additional flow monitoring at key sites along the automated pipeline sections. This would result in available pressure data at approximately 5-8 mile spacing along the pipeline, and flow data at approximately 15-20 mile spacing along the pipeline and at major cross-ties to interconnected pipelines.
- Additional SCADA screens with detailed information regarding the pipeline system including pressure, flow, rate of pressure and flow change, current system configuration, connected major customers and loads, and key system operational requirements.
- Additional information on manual valve positions with a specific focus on valves affecting gas routing. This will likely be accomplished by a combination of adding SCADA points for valve position of select manual valves and providing an electronic “pin map” tool (SCADA screens that allow for the manual input of the open or closed position of valves) for valve positions not communicated via SCADA.
- Building advanced applications for the new data historian being implemented in 2011 as part of an enterprise wide Information Technology project and in conjunction with Control Room Management (CRM). These advanced applications would integrate real-time data with other disparate data and turn it into actionable information by gas operators.

- Integrating GIS and SCADA data historian providing Gas Operators with access to physical pipeline information and geographical reference for SCADA data points.

Additional training enhancements:

- Development of specific line rupture training exercises involving the use of ASVs and RCVs using the training modeling software purchased by the CRM initiative.
- Creation of specific job aids, pipeline shutdown plans and protocols to facilitate identification of line breaks and provide direction to the operator on proper response.

Advanced SCADA tools and technology:

- Advanced composite alarm logic and filtering that performs calculations involving multi-site data to identify specific types of emergency action situations.
- Evaluation and potential implementation of an on-line simulator that would perform sophisticated transient flow simulation for the pipeline system to alert the controller to potential abnormal or emergency operating conditions on the pipeline, such as a large leak or partial line break, and notify the operator.
- Evaluation and potential implementation of various detection technologies connected to the SCADA system, such as leak, pipeline damage and ground movement, that could provide proactive identification of developing risks.
- Evaluation of redundant communications between field valve automation sites and the Gas Control Center, and the available communication technologies available to accomplish this redundancy. PG&E’s gas SCADA system typical communication methods of dedicated lease lines and PG&E owned RF MAS radio system are expected to have a very high level of availability after an earthquake, but redundant communications would provide backup assurance during an earthquake or for other circumstances that could cause a potential single cause communications failure.

Many of these enhancements build off of the foundational work that is currently in progress and funded by the 2011 Gas Transmission and

Storage (GT&S) Rate Case to comply with the requirements of 49 CFR 192.631, Control Room Management. To confirm the appropriateness and direction of these enhancements, optimize their implementation and identify additional improvement opportunities, PG&E will instigate a comprehensive review of its SCADA system and may adjust the above plans based upon the outcome of the study. This review is further supported by the recommendations within the IRP Report.

D. Program Justification

1. Emergency Preparedness and Facilitation of Emergency Response

Installation of automated isolation capability on major pipelines in heavily populated areas increases emergency preparedness, and may reduce property damage and the danger to emergency personnel and the public in the event of a pipeline rupture. Specifically, in the event of a pipeline rupture the installation of automated valve isolation capability provides for taking swift mitigative action, and:

- Can minimize property damage by eliminating the primary fuel source for a pipeline rupture ignited fire in less time.
- Can minimize property damage and increase safety to emergency responders and the public by: (1) allowing emergency response and firefighting personnel to perform their actions unhindered by the high heat intensity flame created by a high pressure natural gas fire; and (2) allowing first responders to better plan their response by minimizing the uncertainty of when the natural gas fuel source will be shut-off.
- Minimizes the quantity of natural gas released during a pipeline rupture, reducing the environmental impact and containing the loss of product.

PG&E believes the expansion of RCV/ASVs is an important part of an overall emergency response system and will help to restore public confidence in the safety of natural gas pipeline systems. Following the San Bruno accident, the Company reassessed the use of RCV/ASVs. We conducted a domestic and international benchmarking study, and spent a significant amount of time speaking with emergency response personnel. This research led us to the conclusion that it would enhance public safety and reduce property damage to install automated isolation capability on the majority of its pipelines in heavily populated areas.

PG&E operates a significant mileage of large diameter, high-pressure natural gas infrastructure in heavily populated areas of northern California. Many of these pipelines are impacted by encroachment and urban growth that has built up around lines, a good portion of which were installed over 50 years ago. In addition, the level of earthquake threat present in California is high relative to most parts of the United States, as is the potential for delayed emergency response to a pipeline rupture caused by an earthquake event. There is a significant level of fire threat posed by environmental factors in many heavily populated areas of northern California and potential for a natural gas fire to be difficult to contain. In addition, the northern California firefighting community has taken the stance that, in the event of a pipeline rupture, a pipeline isolation and blowdown time of more than 30 minutes would negatively impact emergency response and fire containment efforts in response to a high-heat intensity natural gas ignited fire. Automated valves facilitate firefighting emergency response efforts. Finally, although it did not lead to specific legislation requiring the use of automated valves in populated areas, the NTSB has stated that the lack of automatic- or remote-operated valves has prevented companies from promptly stopping the flow of gas to a failed pipeline segment, which exacerbated damage to nearby property.[5] This information provides additional justification for installing automated valves within PG&E's gas transmission system.

2. The Pipeline Industry and NTSB Recommendations

Pipeline industry studies have found that, unlike liquid petroleum pipelines, a large portion of the damage associated with a natural gas pipeline rupture occurs within a few seconds or minutes of the initial rupture before the closure of automated valves would occur. The initial blast is greater for a compressible natural gas pipeline, but escaping natural gas being lighter than air will flow upward into the atmosphere. On the other

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[5] NTSB Report on 1994 Texas Eastern Transmission Corporation (TETCO) New Jersey Pipeline Rupture.

hand, a liquid petroleum pipeline rupture will have less of an initial effect, but liquids will flow out and away from the pipeline spreading fuel in a constantly increasing affected area until isolated.

In its report to Congress, DOT summarized a study by the Southwest Research Institute (SwRI) for the Gas Research Institute.[6] The SwRI study concluded that “almost no casualties would be prevented by the installation of RCVs.” Of a total of 81 incidents studied from 1972 to 1997, virtually all fatalities and injuries occurred at, or very near (within three minutes), the time of initial rupture, long before the ruptured pipe section would be isolated, even with RCVs installed.

Despite the inability of automated isolation valves to mitigate the significant initial damage associated with a natural gas transmission pipeline rupture, there have been identified benefits related to emergency response and property damage mitigation that could be realized through the use of automated isolation valves in situations where the natural gas release ignites. In the same 1999 report to Congress, DOT identified that there is evidence from the NTSB report on the 1994 TETCO 36-inch diameter natural gas pipeline failure in Edison, New Jersey, that faster valve closure may have allowed the fire department to enter the area sooner to extinguish the fire, thereby potentially controlling the spread of the fires to adjacent buildings. The DOT report concluded:

> Automated isolation valves provide the capability for a section of pipe to be isolated quickly upon confirmation of a rupture. Once the ruptured section is isolated and no longer receiving additional gas, any fire would subside as residual gas in the isolated section is burned. A fire would be of greater intensity and would have greater potential for damaging surrounding infrastructure if it is constantly replenished with gas. By providing a definitive time when the line would be isolated following a rupture, it is possible to identify when the fire would subside. This knowledge can serve as a basis for risk assessment and response planning, important considerations in certain heavily populated or commercial areas, and an important factor in maintaining public confidence.

While the DOT Office of Pipeline Safety has been noncommittal on anything other than very limited use of automated valves, the NTSB has

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[6] U.S. Department of Transportation, Research and Special Programs Administration, Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996, September 1999).

consistently recommended the use of automatic or remotely operated valves on high-pressure pipelines in urban areas. A May 2000 United States General Accounting Office report to Congress on Pipeline Safety, stated, the "Safety Board has issued 11 recommendations since 1971 on using valves to rapidly shut down the flow of product to a ruptured pipeline to mitigate damage," recommending automated valves usage be considered in urban areas for high-pressure natural gas pipelines.

3. Evaluation of Valve Automation Program by EN Engineering

PG&E retained ENE to perform a review of the use of ASVs and RCVs in PG&E's proposed Valve Automation Program. ENE was chosen based upon its extensive knowledge and breadth of expertise in gas transmission system engineering, design, integrity management and code compliance. A summary from its assessment of PG&E's Valve Automation Program follows. The full report is included as Attachment 4B.

ENE concluded that PG&E's proposed Valve Automation Program exceeds current pipeline industry regulations. Currently, there are no prescriptive requirements in the prevailing pipeline code, Title 49 CFR Part 192, that require operators to install automated valves. Subpart O requires that operators perform a study of segments within an HCA to determine if ASVs or RCVs would enhance pipeline safety in the HCA; however, the rule does not contain an explicit mandate to install automated valves. The state of California has adopted federal code with regard to valves and valve spacing requirements.

ENE concurs with the Valve Automation Program's focus on the potential benefits to the public and emergency responders, particularly those related to minimizing property damage, which can be achieved by a quick isolation of the natural gas fuel source. ENE concludes that PG&E's Valve Automation Program will enhance public safety in areas with a long lead time for emergency response or during catastrophic outside force events such as earthquakes.

Once PG&E installs the automated valves, it is the opinion of ENE that PG&E will have a valve automation program that leads the industry, particularly in terms of formal selection criteria and quantity of automated valves installed in high population areas. Based on the results of the industry survey conducted by ENE, operators install automated valves based upon their operating history and engineering judgment, but in general their documented processes are not as defined and rigorous as the program proposed by PG&E.

Based on the structured process for identifying line segments for valve automation, ENE does not recommend any additional elements for inclusion in the Valve Automation Program. The program proposed by PG&E as it relates to automated valves is more conservative than prevailing pipeline code and will enhance public safety in areas with a long lead time for emergency response or during catastrophic outside force events such as earthquakes. It is the opinion of ENE that the Commission should approve the Valve Automation Program.

E. Background on Industry Usage of Automated Valves

PG&E's Valve Automation Program goes significantly beyond current code requirements and typical past and current industry practices related to the use of RCVs and ASVs. As part of developing the Valve Automation Program scope and criteria, research was performed to understand current industry perspectives and practices on the use of automated valves. The following paragraphs document the current federal regulations on the use of automated valves, and then summarize both domestic and international industry information obtained regarding their usage.

1. Federal Regulations

Current state and federal regulations do not require automated isolation capability for gas transmission pipelines. Title 49 CFR, Part 192, Subpart O defines Gas Transmission Pipeline Integrity Management requirements. Section 192.935(a) of Subpart O requires operators to conduct risk analyses "of its pipeline to identify additional measures to protect the high consequence area and enhance public safety." It further states, "Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves…"

Section 192.935(c) further discusses the risk analysis requirements as they relate to potential valve automation:

> Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV

> would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors--swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

The Office of Pipeline Safety within the DOT Pipeline and Hazardous Materials Safety Administration has not issued any formal guidance as to how to apply these requirements. Prior to the San Bruno accident, PG&E's risk analyses pursuant to 49 CFR Section 192.935(c) led to a conclusion that expansion of the use of automated valves beyond a case by case assessment was not warranted.

2. Domestic Natural Gas Transmission Industry Practice

In an effort to gauge the industry perspective on the use of Automated Line Isolation Valves ("automated valves", includes both ASVs and RCVs) to respond to line breaks in the gas transmission industry, PG&E contracted with ENE to perform an industry survey. Survey responses were obtained from a dozen companies (including PG&E) involved in interstate and intrastate gas transmission. Responding companies operate a total of 68,000 miles of transmission pipeline (about 23 percent of the U.S. gas transmission pipeline system) with individual companies operating as few as 200 miles to as many as 25,000 miles. The following findings are based upon the survey results.

All but two of the respondents, slightly over 80 percent, use some automated valves to be able to isolate pipe segments in the event of a line break. While the majority of respondents had some usage of automated valves in the event of a line break, usage levels varied greatly, and many times their installation was based upon regulatory and permitting concerns and requirements rather than from formal risk assessments. In general, there is a strong preference of survey respondents to utilize RCVs over ASVs for automated isolation. While ASVs have the advantage of more rapid response, it is clear that inadvertent closures make the choice less desirable.

The subparagraphs below provide additional detail on the survey results.

a. Industry Perspective on Automated Valves

The following is a summary of responses for questions specific to Automated Valves:

- Three companies (33 percent of those providing a response) indicated there is a standard applied when installing automated valves.
- The greatest single factor considered when installing an automated valve is population, which drives class location and HCAs. The next most mentioned factors were operational concerns and the time to isolate a pipe segment.
- Similarly, the greatest single factor under which an operator may evaluate automating an existing valve would be the change of population density around an existing line.
- With the exception of recent pipeline projects subject to special permits, formal documented studies are not completed regarding installation of automated valves on new pipelines.
- The primary consideration to determine automated valve spacing is 49 CFR Part 192 maximum valve spacing requirements.
- When considering ASV or RCV, the preference is to use RCV because it requires human intervention to reduce the likelihood of inadvertent valve closure.

b. Industry Perspective on Automatic Shut-Off Valves

Six companies, 55 percent of the respondents, have some automatic shut-off valves installed in their pipeline system. Listed below is a summary of responses for questions specific to automatic shut-off valves:

- Over 85 percent of operators with automatic shut-off valves have experienced a false valve closure.
- Unusual operating conditions, freezing of the signal line, and instrumentation failures, were stated as factors causing false closure of ASVs.

- Operator efforts to minimize false valve closure included disabling of the ASV controls, modifying the ASV setpoints, and converting the valves to RCVs.

c. Industry Perspective on Remote Controlled Valves

The survey also addressed the use of RCVs for line rupture control rather than other purposes. Eight companies, approximately 75 percent of the respondents, have some remote control valves installed in their pipeline system for line break purposes. Listed below is a summary of responses for questions specific to remote controlled valves:

- When using RCVs all respondents use the valves for the dual purpose of operation control and rupture/line break control.
- Only one company identified an incident which occurred causing the valve to close inadvertently; two companies indicated an incident where the valve failed to close when commanded.
- Operators view the primary advantage of RCV to be the human evaluation of the condition of the pipeline before closure. The primary disadvantage is the potential interruption of power or communication with the valve controller.
- Most operators do not use any line break detection software. Operators monitor pressure, flow, and rate of change alarms to identify line breaks.
- Respondents were split on the existence of a formal procedure to recognize and confirm a line break prior to closing a valve.
- Pipeline operators rely upon operator qualification and written procedures to maintain the readiness of staff to recognize and respond appropriately in the event of a failure.

3. International Natural Gas Transmission Industry Practice

PG&E contracted with Energy Experts International to gather information from natural gas pipeline operators and utilities in Japan, France, Germany, Netherlands, Spain and the United Kingdom regarding their use of automated isolation valves for gas transmission systems. The companies contacted operate a total of approximately 50,000 miles of gas transmission pipeline. The specific results varied, but several common themes were:

- All contacted companies reported usage of RCVs for automated isolation of pipeline segments, particularly in heavily populated areas, in the event of a line rupture. For each of these companies, a systematic program was in place which defines when RCVs are installed.
- There was a strong preference for remotely operated valves over automatic shutdown valves. Only one European company had automatic line rupture controls in operation, and these are being converted to remotely controlled valves due to concerns regarding the triggering mechanism not being reliable and false closures.
- RCV installations were typically installed at 5-10 mile spacing. RCVs were ball valves using a variety of actuator types.
- No problems were reported with the use of RCVs.

Japan had the most sophisticated system with RCVs utilized by the three largest utilities throughout their transmission networks, nearly all of which run through very heavily populated areas (a high percentage of which is Class 4). Since gas is produced from Liquefied Natural Gas (LNG) located near the population centers, there are no long cross-country transmission pipelines in Japan. Ground movement sensors that are installed at the district regulator station entry points into their gas distribution networks are used in Japan.

F. Project Phases

In order to effectively manage resources and capital expenditures, PG&E will implement the Valve Automation Program in two phases, with the second phase composed of an “A” and a “B” component. A map showing the locations prioritized for Phase 1, 2A, and 2B implementation is provided as Attachment 4A. In this Implementation Plan, PG&E is only seeking cost recovery for Phase 1.

1. Pipe Segment Phase Prioritization

Determination of phase priorities was aligned with the two primary factors in segment selection: population density and PIR. The following table shows the various miles of PG&E gas transmission pipeline by Class, HCA and PIR value, and highlights the focus of Phases 1, 2A and 2B.

TABLE 4-3
PACIFIC GAS AND ELECTRIC COMPANY
PIPE MILES BY PIR, CLASS AND HCA

Line No.	PIR	HCA Class 3&4	Non-HCA Class 3&4	Class 3&4 Miles	HCA Class 1&2	Non-HCA Class 1&2	Total Miles
1	501+	132(a)	23(c)	155	56	1,806	2,016
2	301-500	208(a)	68(c)	277	10	394	680
3	251-300	98(b)	41(c)	139	3	289	431
4	201-250	133(b)	71(c)	204	4	313	521
5	151-200	153(b)	128	281	4	284	569
6	101-150	161	268	430	3	453	886
7	0-100	60	179	239	1	418	658
8	Totals	947	778	1,715	80	3,958	5,763

(a) Focus of Phase 1.

(b) Focus of Phase 2A.

(c) Focus of Phase 2B. Phase 2B also includes unsustained pipe lengths of Phase 1 & 2A segments.

Note: The pipe mileage table is based upon a January 3, 2011 GIS database snapshot for all DOT gas transmission designated pipe not including Gas Gathering. All mileage statistics for the Valve Automation Program and pipe segment analysis are based upon this data snapshot.

2. Description of Phase 1 Program (2011-2014)

Phase 1 will provide automated isolation capability for 276 miles of pipe in Class 3 HCA locations with a PIR > 300 feet and Class 4 locations with a PIR > 100 feet. To automate these pipe segments, an additional 246 miles of adjoining segments are required to be automated, of which 125 miles otherwise would have been automated in Phase 2. Phase 1 work results in a total of 522 miles of pipeline with automated isolation capability. It also includes automatic controls for pipelines crossing 16 active earthquake faults.

Phase 1, which contains work at 80 specific valve sites, is planned to provide automated isolation capability for 185 valves, and is planned to upgrade the controls for 43 valves that currently have some remote control capability. As part of this effort, at least 50 new valves will be required to allow for this automation. Additionally, PG&E will install 30 new flow meters to provide necessary flow information to facilitate decision making on when to isolate a pipe segment. The following two tables provide additional details on the specific valve automation work by year and geographical area:

TABLE 4-4
PACIFIC GAS AND ELECTRIC COMPANY
VALVES AUTOMATED BY AREA IN PHASE 1 (2011-2014)

Line No.	Geographical Area	Existing Valves to be Automated	Replaced or New Valves Automated	Existing Automated Valves to be Upgraded	Total Valves Automated in Phase 1
1	Peninsula (2011 Construction)	12	8	9	29
2	Peninsula (2012 Construction)	12	17	10	39
3	San Jose	13	2	6	21
4	Antioch to Richmond	27	7	3	37
5	Oakland to Fremont to Livermore	20	4	2	26
6	Brentwood Area	3	5	5	13
7	Sacramento Area	6	5	1	12
8	Vallejo-Fairfield Area	15	2	0	17
9	Stockton-Modesto Area	17	0	1	18
10	Bakersfield Area	5	0	2	7
11	Eureka Area	3	0	2	5
12	Barstow Area	2	0	2	4
13	Total	135	50	43	228

Note: Based upon preliminary analysis of existing valve installation conditions.

Phase 1 includes line segments that meet either of the following criteria:

- Sustained length of HCA pipe within a Class 3 location with a PIR of three hundred feet (300') or greater.
- Class 4 with a PIR of one hundred feet (100') or greater.

For identifying a sustained length, a section of pipeline had to contain at least five (5) miles of HCA and the HCA pipe had to be over 50 percent of the pipe length between existing isolation valves. Non-sustained lengths were deferred to Phase 2. Based upon PG&E's pipeline system footages, approximately 80 percent of Class 3 pipeline segments with a PIR of over 300 feet are also HCAs, and just over 80 percent of these pipe segments have sustained lengths of HCAs.

Additionally, some segments not meeting the Phase 1 criteria were included in the Phase 1 implementation due to efficiencies gained by making the work part of Phase 1. This typically occurred where segments were contiguous to Phase 1 segments or when valve automation work that would have been part of Phase 2 segments is required within stations where Phase 1 work is planned.

Phase 1 also includes valve automation for unmitigated pipeline segments crossing active earthquake faults that met the following criteria:

- The earthquake fault was identified as having a greater than two (2) percent probability of having a 6.7 or greater magnitude earthquake event within the next 30 years.
- The segment is in a Class 3, Class 4 or Class 1 or 2 HCA location and the line segment had a PIR of one hundred fifty feet (150') or greater.

The vast majority of mileage within Phase 1 is based upon the Class 3 HCA, PIR > 300 feet, criteria. This classification of pipe is highlighted in the following map for the portion of PG&E's service territory from north of Chico to south of Fresno. There are only small portions of HCA, PIR > 300 feet pipe outside of this map in the Burney, Bakersfield and Barstow areas.

FIGURE 4-8
PACIFIC GAS AND ELECTRIC COMPANY
CLASS 3 HCA PIPE WITH PIR > 300 FEET

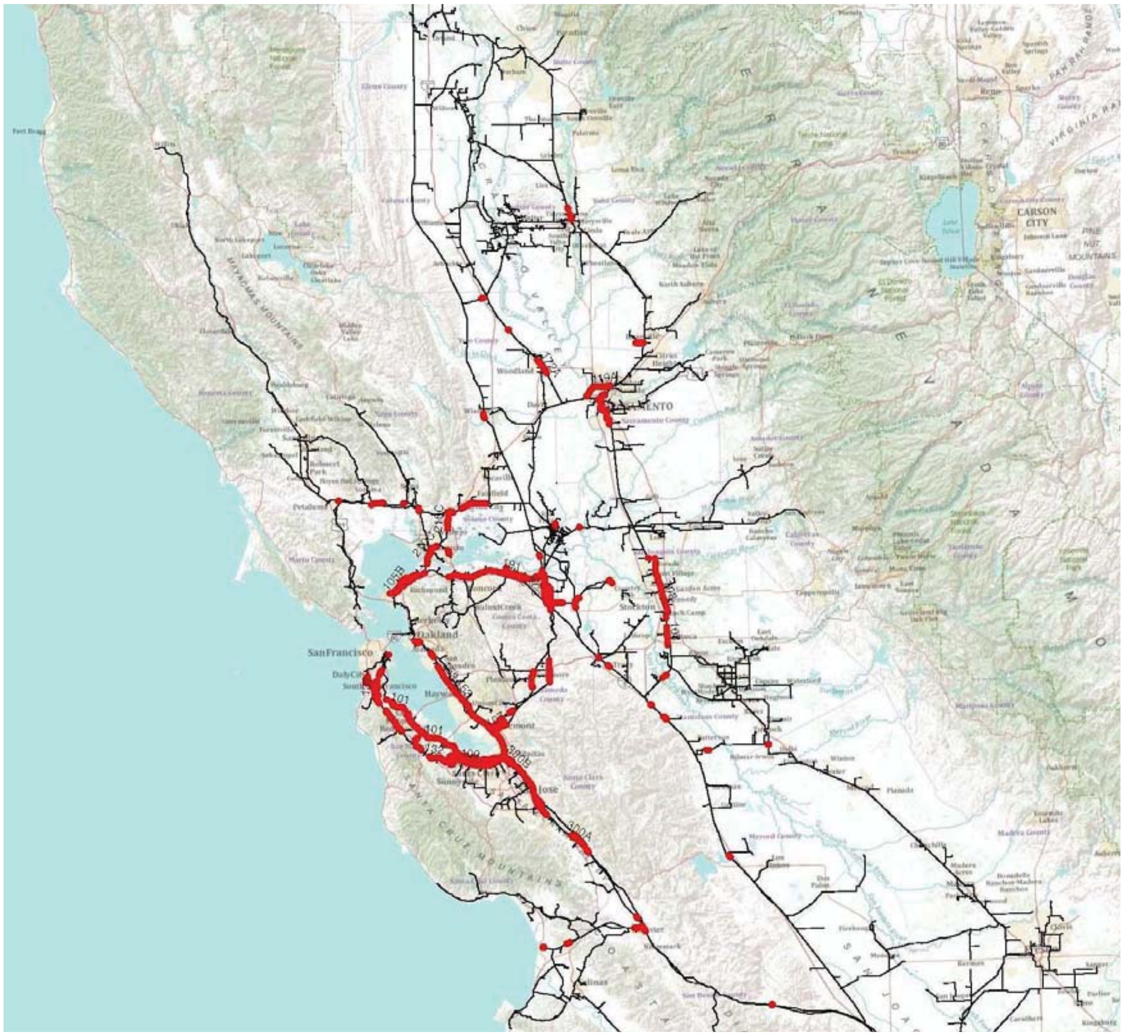

Figure 4-8 shows that the overwhelming majority of Phase 1 projects will take place in the greater San Francisco Bay Area due to the population density of this region.

A subset of Phase 1 work was chosen for implementation in 2011 to “launch” the program. The launch work will focus on sites within the San Francisco Peninsula between Milpitas and San Francisco and will allow us to identify standardized processes and designs that should be used for program implementation, to gain experience in the types of issues that will be faced for various installation scenarios, and to better understand cost and schedule components of program execution.

3. Description of Phase 2A

Phase 2A includes line segments that met all of the Phase 1 Class 3 HCA criteria except for PIR value. Whereas Phase 1 focused on segments with a PIR over 300 feet, Phase 2A includes those sustained length line segments with a PIR value between 150 feet and 300 feet. Phase 2A consists of installing automated isolation capability on approximately 535 miles of gas transmission line, of which 345 miles are in Class 3 locations. This work will require the automation of roughly 130 valves.

4. Description of Phase 2B

The Phase 2B implementation includes the remainder of the in-scope Class 3 locations. This includes the remainder of Class 3 line segments with a PIR greater than 200 feet that were not included in Phases 1 and 2A. It primarily consists of scattered short segments of Class 3 pipe on longer lengths of pipeline traversing predominantly Class 1 and 2 areas. Phase 2B consists of installing automated isolation capability on approximately 725 miles of gas transmission line, of which 235 miles are in Class 3 locations. This work will require the automation of roughly 200 valves.

G. Specific Projects Scope Determination

1. Phase 1 Valve Automation

a. Determination of Specific Automation Segments

Before estimating valve automation project costs, the specific project scope for each Phase 1 project was determined. An estimating team of ENE engineers, working in conjunction with PG&E project and planning engineers, and utilizing the defined Phase 1 scope of segments to automate, first determined the start and end points for each automation segment. This was done utilizing information obtained from system operating maps, station operating diagrams, GIS data, and current SCADA information. This information was combined with PG&E knowledge of customers connected to various segments, to determine valve spacing and specific start and end points.

Where feasible while still maintaining desired valve spacing, valve sites that are already automated were selected. These valves may have been automated for other purposes than for pipe segment isolation, but can easily be equipped with this functionality. Automation of an existing valve was the next most attractive option. Installation of a new mainline valve or construction of a large multi-valve vault was generally the least attractive option. In most cases start and end points were aligned with existing valve locations.

b. Determination of Pipe Segment Automation Requirements

The team next determined automation requirements for each pipe segment using the same information discussed above plus construction documents for existing sites. This determined the full scope of automation work required for Phase 1. Providing automated isolation of a pipeline segment is not as simple as automating a mainline block valve at either end of the pipeline segment. For each pipe segment to be equipped with automated isolation capability, it is required to assess all potential points where gas could enter the segment. This includes not only the start and end points of the mainline segment, but also all taps off the pipeline within the segment. For each point, a determination is needed as to the type of equipment and controls required to most effectively and efficiently isolate the segment. The following highlights some of the assessments that are required:

- Taps connecting the pipeline segment to another gas transmission pipeline (cross-tie connection). An assessment is required to determine if valves in this cross-tie piping need to be automated or if the cross-tie valves can be kept in the closed position and only opened when required to address an abnormal operating condition.
- Taps that supply gas to smaller diameter transmission or distribution feeder main systems without any reduction in pressure. An assessment is required to determine if the tap valves should be automated or check valves added at the tap location to prevent backflow into the isolated pipe segment and to minimize the extent of the isolated piping. Particular attention needs to be paid to gas systems downstream of tap valves that can be supplied from other gas systems with an objective of minimizing the potential customer outages due to isolation of the pipe segment.

- Taps that supply gas to regulator stations, which then serve lower pressure gas systems. If the stations have pilot-operated regulator valves, the regulator valve controls can be easily modified to prevent backflow through the regulator station and into the isolated segment. For taps supplying gas to larger regulator stations with controller-operated regulator equipment, check valves can be installed in the tap line to prevent flow of gas backwards through the regulator station.
- Taps on either side of mainline valves that are connected together (i.e., bridle valves) at the start and end of each segment require special attention to ensure gas cannot bypass around the mainline valve into the isolated pipe segment. An assessment is required to determine if one of the bridle valves can be kept in the closed position during normal operations, or if the bridle valves require automation or check valves installed to prevent gas bypassing around the mainline valve.

For the Phase 1 projects, initial assessments have been made as part of the feasibility and preliminary scoping process; further review and confirmation will be made during the later stages of the engineering process.

c. Determination of Specific Projects

The work scope was then broken into distinct projects. Projects consist of all work scope items related to a specific location. A single project location often included portions of work for multiple Phase 1 pipe segments for those cases where a specific location had multiple incoming and outgoing pipelines associated with it. For each project location, the station was then reviewed for any additional work scope that would have been associated with Phase 2 work scope at that site, but should be moved into Phase 1 for efficiency purposes. In each specific project, PG&E also included any minor tap work associated with the upstream pipeline segments up to the next project location.

d. Determination of Specific Project Design Requirements

After segregating the work into specific projects, design requirements for each project had to be created. These design requirements then formed the scope basis for the project cost estimates. The design requirements assessment work generated details related to:

- Existing valves with automation that require additional controls for use in isolation of pipe segments.
- Existing manual valves that require valve actuators and automation control packages. Figure 4-9 depicts manual valves that are installed in a vault, and Figure 4-10 depicts a buried valve with manual gearing installed above ground. These are two examples of types of existing valves that could be automated.

FIGURE 4-9
PACIFIC GAS AND ELECTRIC COMPANY
MANUAL VALVES INSTALLED IN A VAULT

FIGURE 4-10
PACIFIC GAS AND ELECTRIC COMPANY
BURIED VALVE WITH MANUAL GEARING INSTALLED ABOVE GROUND

- Existing manual valves that require replacement or relocation and then automation. The following photos depict manual valves that would need to be replaced prior to automation.

FIGURE 4-11
PACIFIC GAS AND ELECTRIC COMPANY
EXISTING MANUAL VALVES REQUIRING REPLACEMENT

- New automated valves and new check valves that need to be installed.
- Instrumentation, metering, pressure monitoring and controls required as part of valve automation at each site.
- New SCADA installations or upgrade requirements at each site, including power and telecommunications requirements.

- Existing regulator stations that need controls modifications.
- Piping modification requirements at each site.
- Site improvement requirements including vault installations, fencing, paving, and land acquisition and permitting.

FIGURE 4-12
PACIFIC GAS AND ELECTRIC COMPANY
EXAMPLE OF SITE IMPROVEMENTS

All valves being automated as part of the Valve Automation Program are installed beneath the ground surface. The valve actuator equipment that is required for an automated valve to be operated can be installed directly on top of the valve or on top of a “valve extension” that extends the valve shaft upwards to allow the valve actuator to be located aboveground for a buried valve. The valve actuator needs to be accessible for maintenance, so it cannot be buried. For situations where the valve shaft cannot be extended aboveground, such as for valves buried beneath streets or sidewalks, a vault needs to installed around the valve to allow the valve actuator to be mounted directly on top of the valve and for it to be accessible to maintenance personnel.

To determine whether or not an existing valve requiring automation should be automated or if the existing valve must first be replaced or relocated, the following information must be gathered:

- If a pipeline mainline isolation valve, does the existing valve allow for In-Line Inspection (ILI) of the pipeline?
- Does the valve type allow for automation?
- Does the valve condition provide for reliable automation?
- Does the valve installation configuration allow for automation?

Mainline valves that do not allow for ILI, such as gate valves, plug valves and reduced port ball valves need to be replaced, as do floating ball valves due to age of these valves and high torque requirements. Also, valves that do not fully shut-off flow between two pipe segments and valves that are hard to turn will be replaced if they cannot be repaired through maintenance. These valves were assumed to be repairable for this initial assessment, but will be further evaluated during subsequent engineering. Additionally, valves that are buried in a configuration or location that does not allow for their automation will be replaced.

Locations requiring vault installations represented a particular challenge, and the design requirements for these locations assumed vaults could be installed around the valves but also assumed some relocation work would be required to PG&E lines or facilities of third parties to provide for the vault installations. Specific design requirements for these locations will be solidified in the detailed engineering phase of work.

For any sites requiring mainline valve automation, the mainline valve, any bridle taps and related piping will be upgraded to allow for future inline inspection of the pipeline.

2. Phase 1 Metering

Work scope for Phase 1 metering projects was determined by utilizing the list of pipelines to be equipped with automated isolation capability in the first phase of valve automation. Each of these pipelines was evaluated to determine where additional metering would be beneficial to facilitate gas control operator decision making related to line rupture events. A general rule of thumb of every 15-20 miles was utilized as a starting point based upon input from PG&E's Gas Control Operations Engineering group. As controllers gain operating experience with the new meter data, an assessment will be done to validate the rule of thumb and to determine whether additional metering is required. Due to the limited number of meters to be installed (thirty new meters) these meters were lumped into a single Phase 1 metering project.

H. Program Changes Based on CPUC Workshops and Feedback

PG&E supports efforts to enhance coordination and communication between the Implementation Plan program management team and the Commission and other intervenors regarding proposed Valve Automation Plans. At the CPUC Gas Implementation Plan Workshop held on June 22 and 23, 2011, and in subsequent discussions, PG&E received valuable information and feedback regarding areas for improvement of the proposed program and approach.

Specifically, PG&E received feedback that all Class 4 locations should be considered for automation in Phase 1, not just those Class 4 locations with a PIR > 100 feet. This change would have no effect on pipe segments identified for automation because PG&E currently has no gas transmission pipe as defined by DOT in a Class 4 area with a PIR < 100 feet. However, any pipe that may fall into this category in the future would likely have physical characteristics that would make it prone to leak rather than rupture and installation characteristics more similar to gas distribution networked pipe systems that would make segment isolation difficult. Any pipe in this category would also pose less firefighting issues due to the smaller impact radius. Therefore, PG&E’s valve automation program and approach described in this chapter was not adjusted based on this feedback.

I. Project Cost Estimating Methodology

1. General

PG&E retained ENE to estimate costs for Phase 1 of the Valve Automation Program. The accuracy of the estimates of capital expenditures were Class 4 level estimates (-30% to +50%) as defined in the Association for the Advancement of Cost Engineering International Recommended Practice No. 18R-97.

ENE has significant expertise in transmission pipeline design and distribution system designs including metering and regulating stations, compression, gas conditioning, valve automation and controls, electrical, metallurgy, and pipeline integrity. ENE relied upon project costs from work completed for other natural gas utilities for similar valve replacement projects and similar facility revisions, the knowledge and experience of ENE in-house staff, and pricing from subcontractors, material manufacturers, suppliers, and consultants.

PG&E provided input to the cost estimating process, sharing knowledge on known specific site issues that potentially could have a cost impact, PG&E design and construction standards, PG&E project overhead rates, and contract construction prevailing wage labor rates.

2. Project Estimating Approach

Cost estimates were generated using the list of specific project work scope items and a unit cost database for materials and labor costs associated with each specific work scope item. The level of project definition was less than 15 percent at the time of the estimate's development.

Protocols to determine the work effort per site were established to ensure consistent estimates across the system. In addition to the specific project work scopes, other considerations in the development of the individual estimates included site congestion, site complexity and difficulty in providing electrical power to the site.

3. Unit Cost Approach

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. Material unit costs were developed for valves, actuators, pipe, fittings, valve actuation instrumentation, valve control equipment, SCADA hardware (including pressure transmitters), and fencing and gravel. Unit costs were established for various sizes of materials where applicable. Construction unit costs were developed for valve automation installation, valve automation upgrade, valve installation, site restoration, extended controls trenching, stopple fitting installation, bypass installation, telecommunications, Remote Terminal Unit (RTU) installation, vault installation, clearance execution, land and permitting, electrical power connection and district regulator station modifications. Engineering unit costs were developed for design engineering, SCADA programming, and mapping and records. Unit costs were established for various levels of complexity for construction and engineering tasks.

The type of valve automation work at each site fell into one or more of the following categories which could then be utilized for comparison of estimates between projects:

- Automate an existing valve.
- Replacement of an existing valve to include automation.
- Installation of a new valve (with automation).
- Upgrade of existing automated valve hardware.
- Automation or replacement of existing valve in vault.

Once a few specific project scopes were created, these unit costs were applied and the results compared against expected costs for a project of this magnitude. This served as a quality control check.

4. Description of Typical Valve Automation Types and Associated Costs

The scope of work for each type of automation will vary in terms of both material and labor costs. Assumptions for each type are described below.

a. Automation of an Existing Valve

The estimates reflect the costs associated with the automation of an existing valve. Scope includes the material and labor needed for mounting a new actuator, excavating and installing upstream and downstream sensing lines, conduit, power supply, SCADA work, and any additional items required to complete the retrofit including backfill and permanent restoration.

b. Replacement of Existing Valve at Same Location

The work scope for projects where the existing valve requires replacement includes both removal of an existing valve and the installation of an automated valve assembly. This included any piping work required to make the pipe section including the valve assembly capable of ILI.

Areas found to have excessive constructability issues including substantial impact to the public were noted. In some cases, it was determined that it was more feasible to abandon the existing valve location and relocate a new valve assembly to a new site. Removal and restoration costs were included for the retired facilities.

c. Installation of New Valve

For the purpose of these cost estimates, a new valve installation refers to installation of a new main line valve not previously in service along the pipeline system. Thus, additional costs associated with the construction of a new site, such as permitting and land acquisition, fencing or other standard security measures, electrical systems and telecommunications were included in the estimates.

d. Upgrade of Existing Automated Valve

In cases where the existing valve is already automated, existing hardware and/or software will be upgraded to comply with the design and operational standards created by this program. Therefore, costs for engineering, materials, and labor were incorporated.

e. Automation or Replacement of Existing Valve in Vault

Under certain circumstances, automating valves at the selected site may require installation of a large vault(s) installed below ground under roadway pavement. For these cases, the following additional costs were included in addition to the cost to automate, replace, or install the valve(s):

- Costs—both material and labor—associated with the installation of the vault(s) required for valve automations.
- Electric actuators were assumed for all vault applications.
- Costs to resolve conflicts created by vault installations with any nearby underground facilities and other utilities.
- Roadway pavement restoration costs.

Excavation and restoration costs are recognized to be substantial for projects of this type.

5. Cost Basis Assumptions

a. Economic Assumptions

An average labor productivity rate was utilized, which assumed the project will progress at a typical rate and is based upon a normal project schedule duration of this type. No special considerations for extreme weather conditions or for obstacles not typical of Right-of-Way (ROW) construction were included in this estimate.

It was assumed that pipelines will be taken out of service for valve replacement/installation where required, and no special provisions were considered to maintain system flows unless noted. However, typical clearance costs were factored by location into the estimates.

Unit cost estimates were based in 2011 dollars. After determining an overall project schedule, an escalation factor of 3.12 percent per year was applied for projects after 2011.

b. Exclusions

The estimates do not include costs for unforeseen items that require specialized equipment or labor, or require specialized permits. No unique construction costs outside of those specified in the unit cost definitions were included. Potential costs to comply with atypical permit constraints or for handling site specific soil contamination beyond minimal levels were also not included. It was assumed that pipelines are in existing ROWs and that only the cost of modifications to existing easements will be required for any new above ground facilities.

It is assumed that the valve assembly will be cathodically protected with the pipeline; therefore, no significant cost for a corrosion protection system was included in the cost estimate. Also, the cost of any pipeline gas that is required to be purged (i.e., blown down) to atmosphere to allow for piping or valve replacement work to occur was not included in the cost estimates.

6. Direct Cost

Direct costs considered in these estimates include materials, construction labor, and engineering.

a. Material

The unit pricing for materials largely consists of quotes obtained between the fourth quarter of 2010 and first quarter of 2011. Adjustment to material pricing would be required if there is a substantial change in market conditions.

(1) Valves

The estimates were based on ball valves with the following characteristics: trunnion mounted, weld ends, full bore, American National Standards Institute rated to meet MAOP, and supplied with a valve extension and coated for buried service.

(2) Pipe and Fittings

Cost estimates were based on standard schedule 40, grade X-52, API 5L pipe coated with fusion bonded epoxy. Lengths and specifications to meet minimum 49 CFR Part 192 requirements for fabricated assemblies were also assumed. Fittings of commensurate size and grade were also assumed.

(3) Actuators

The cost estimates included the necessary actuator components to automatically operate a ball valve. Two different actuator types were used to generate the costs estimates:

(1) Low pressure gas powered double acting piston actuator for aboveground applications.

(2) Direct Current motor driven electric actuator for vault applications.

(4) SCADA

Cost estimates include the materials needed to provide communications between the automated valves and the gas SCADA system.

b. Construction Labor

For purposes of this cost estimate methodology, the general category "construction labor" was used to account for both contract and company labor required to complete valve automation tasks outlined in the individual project work scopes.

(1) Pipeline Contractors

Unit pricing for contractor labor was derived using a prevailing wage for pipeline station work in the state of California of $120 per manhour, which was supplied by PG&E and based upon current contract rates for controls construction. The number of associated hours and crew size was tailored to the scope of work needed per location. Unit hours to complete identified tasks associated with valve assembly installation or retrofit are based on historical data.

Project duration of twenty-five (25), 10-hour days were assumed for valve installation and replacement projects. Valve automation or upgrade of existing automation projects utilized a ten (10) day (ten hour day) duration. Crew sizes were scaled in accordance with diameter of the valve in question.

Work items include pipe, fittings and valve installations, instrumentation and controls installation, hydrostatic testing, x-ray, excavation and backfill, work associated with installations such as concrete pads or pipe supports, and construction inspection.

(2) Restoration

Site restoration costs for valve replacement or installation were assumed to be more significant than those for automation or upgrade to existing automation project. However, in both cases, some restoration work will be necessary due to anticipated trenching for control lines and electrical conduit.

(3) Vaults

Estimated costs associated with the installation or relocation of a vault, or the abandonment of a buried vault structure, were included in the construction labor category for the purpose of this high-level estimate. Material for the vault installation, as well as backfill and materials for site restoration, were included in this unit cost. Also included were typical costs to address any conflicts created by the vault installation such as interferences with other buried pipes and structures.

(4) Clearance Cost

Costs associated with gas continuity planning and coordination such as LNG/Compressed Natural Gas (CNG) trailers were noted in applicable estimates. Each project as outlined was determined to have either a “high,” “medium,” or “low” clearance cost and typical values were assigned. For example, locations requiring LNG/CNG trailers, cross compression, or temporary bypass would constitute a high clearance cost.

(5) Land, Permit, Environmental and Safety

Sites with a large impact area or within public ROW are assumed to have a large land, permit, environmental and safety cost. Items included in the estimate are dollars for handling items such as environmental biological issues, storm water pollution prevention plans and groundwater mitigation, shoring, additional temporary work area protection, and traffic control. Minimal real estate costs for working space, or temporary easements, were outlined in each work estimate.

Each project as outlined was determined to have a “high” or “low” land, permit, environment and safety cost and typical values were assigned for each. Land costs within an existing station were assumed to be zero.

(6) Power Supply, Telecommunication, and SCADA

Cost estimates took into account whether the selected site has existing power, telecommunication, and SCADA infrastructure to accommodate the valve automation.

(7) District Regulator Station Retrofits

In order to ensure gas from distribution systems do not backfeed gas into an isolated transmission line segment in cases where the automated valves are actuated, evaluation and potential modifications to District Regulator Stations was included. A unit cost was applied for each identified location.

(8) Adjacent Valve Projects

In areas where multiple valves are located within the limits of construction, a gain in labor efficiency is recognized for each automated valve. Locations were reviewed and a multiplier of 0.35 for additional valve assemblies within the same site. The largest valve size was assumed to be the primary location and a multiplier of 1.0 used for that particular valve assembly.

c. Engineering and Other Non-Construction Labor

(1) Engineering

Work items such as preliminary engineering and design, survey, subsurface utility engineering work, geotechnical study as well as the land and environmental investigations were included based on the scope of each individual site. SCADA/RTU programming, mapping, records updates and estimating were also incorporated in to the cost for all locations.

Each project was determined to require either "major" or "minor" design engineering. A unit cost was applied for SCADA/RTU programming of each RTU device. Mapping and records updates relative to the project were assigned a unit cost per project.

(2) Project Management

The costs associated with the management of individual projects were estimated at 4 percent of the project engineering, material and construction direct costs. These include project manager and project controls costs associated with the planning, monitoring and tracking of specific project tasks, and the PG&E oversight of various contractors working on specific projects to ensure work quality and efficiency.

(3) Customer Outreach

The valve automation work will require significant customer and community outreach to notify and educate affected customers of any work that may impact them and address any concerns they may have. The objectives of customer and community outreach for the Valve Automation Program are to:

- Ensure local government officials, customers and communities are well informed about PG&E's Valve Automation Program and educated about field activities before, during, and after work that may impact them.
- Provide multiple ways for customers to get answers to their questions, particularly regarding any safety concerns. Ensure ongoing two-way communications between PG&E and local customers and the community.
- Initiate outreach well ahead of visible PG&E onsite presence. Ensure there are no surprises to local officials, customers and the community.

A cost adder of 0.54 percent was applied to each project to reflect the expenses associated with integrated customer and community outreach. Key characteristics, methods of outreach, and nature of expenses are described in more detail in Chapter 3.

(4) Program Management Office

Due to the nature and size of the Implementation Plan effort, PG&E has retained an independent contractor to run a Program Management Office (PMO) to ensure successful implementation of this plan. The PMO is responsible for overall program management including that of the Valve Automation Program. PMO costs are not included in the individual project cost estimates and are addressed at the program level. Information about PMO costs, and the roles and responsibilities of the PMO, are included in Chapter 7.

7. Indirect Cost

Indirect cost percentages were applied to each project in accordance with PG&E guidelines. Costs associated with handling, storage, and procurement of material were calculated to be 29 percent of the overall estimated material costs.

Costs assumed an Allowance for Funds Used During Construction rate of 5.24 percent of total project costs. This rate was used based on anticipated project duration, for engineering and construction, of 13-18 months.

8. Contingency

No contingency was included in individual cost estimates. Contingency is addressed on a program level, and is discussed in Chapter 7.

Based upon the cost estimates being derived from only preliminary project definition, and the level of cost estimating uncertainty, contingency usage will likely be required on a number of projects. Contingency usage will be required if additional design details are discovered during the engineering phase that result in additional valve replacements and/or expanded piping construction work.

9. Metering Cost Estimates

Flow Metering cost estimates assumed a typical clamp-on ultrasonic operational meter installation based upon PG&E historical costs. It was assumed that the clamp-on meter would be installed on below ground pipe inside of a new vault with the required associated instrumentation installed above ground. The same overheads were applied as for the valve automation work.

10. Other Cost Estimates

a. SCADA Enhancement Projects

The cost for SCADA Enhancements was determined based upon the knowledge and experience of PG&E subject matter experts on the subject and PG&E historical costs of similar efforts where available. These were confirmed as reasonable by contractors with SCADA system subject matter expertise. The costs of these enhancements are primarily an expense cost. Costs were estimated for the following distinct efforts:

- Comprehensive review of existing SCADA system and best practices industry review.
- Additional SCADA screen development and implementation for enabling operators to identify and evaluate an emergency event.

- Adding valve position data points to SCADA for valves most likely to affect pipeline configuration (capital) and development and implementation of an electronic pin map for valve position indication for key manual valves not currently on SCADA (expense).
- Development and implementation of pipeline shutdown plans and protocols, including creation of specific pipeline shutdown SCADA screens for each automated pipe segment.
- Development and implementation of a gas control operator training program specific to the use of all new tools and processes in line rupture identification and response.
- Development and implementation of alarm management, advanced situational awareness composite alarm logic and filtering applications, and situational awareness overview screens.
- Development and implementation of linkage between GIS system and gas SCADA data system.
- Assessment of online pipeline simulator technology which would assess pipeline operating conditions on a real-time basis for abnormalities.
- Research, evaluation and testing of various leak, pipeline damage and ground movement detection technologies that could be integrated with SCADA.
- Research, evaluation and testing of redundant communication technologies that could be employed in communicating between field sites and Control Centers.

b. Operation and Maintenance Additions

For every new automated valve and meter that will be installed there will be additional maintenance above and beyond what is required for a manual valve. This is a result of the additional communications, instrumentation, and controls equipment required by the automation. Maintenance associated with an automated valve that is additional to that required for a manual valve includes:

- Performing calibration and accuracy verification for the pressure transmitters.
- Performing inspection and testing of the SCADA RTU for communicating with the valve.
- Performing annual inspection of the instrumentation and control equipment used in valve automation and control including the valve actuator, valve position switches, solenoid valves, local control panel and other auxiliary equipment associated with valve control.
- Performing full end to end operability testing of the remote controls for automated isolation valves (new requirement that will apply to all existing and new automated isolation valves).

The additional automated valve maintenance is on average expected to require an additional eight (8) hours per valve per year. The electronic pin map system will also require scheduled valve position field verifications for all key manual valves included in this system to ensure its accuracy.

Additionally, there will be a one-time expense charge to develop a formal technician training program for automated isolation valve operation and maintenance. This will be a one day class that approximately 200 field technicians will be required to take. Also proposed is an annual pipe segment shutdown training requirement for all gas maintenance field personnel.

For every new operational flow meter that will be installed, there will also be maintenance required for this equipment. This includes calibration and verification of the transmitters associated with flow calculation and performing meter diagnostics to verify accurate operation on a twice per year basis. The maintenance required for each new operational flow meter is expected to be four (4) hours per every six-month maintenance visit per meter. There is also forecasted to be one additional technical specialist required to provide ongoing support and training to field personnel on automated valves, RTUs, and operational meters.

Besides additional field maintenance and operations costs, there will be additional operating costs to Gas Control Operations associated with the addition of 185 automated valves (including valve position indication for each valve on SCADA), 40 new RTU sites and approximately 300 new pressure points, and the associated supervisory control and alarms associated with this equipment, as well as the operating costs associated with increased gas system monitoring, system verification and testing. The increased operating requirements is estimated to result in the need for an additional manned operational control room desk within Gas Control, and the need to increase Gas Control staffing by three additional persons to manage this desk. In addition, all Gas Control Transmission Coordinators and Operators will have additional annual training associated with the required increased level of preparedness to identify and respond to rupture events, and with the additional tools and processes to accomplish enhanced response. Unit costs of $125 per man-hour for operations personnel and $140 per man-hour for maintenance personnel were used in the cost estimates.

J. Summary of Program Costs

1. Cost Forecast Summary (Phase 1)

PG&E established new Major Work Categories (MWC) to consolidate and categorize expenditures by asset and work activities. The MWCs are further broken down into subcategories called Maintenance Activity Type (MAT) codes, to group similar work together. The MWCs and MATs used by PG&E to define the Valve Automation Program projects are discussed below.

Category MWC-2H includes all valve automation, metering and valve position remote monitoring capital installations, except for the portion of the work benefitting Standard Pacific Gas Line Inc. (StanPac) facilities. The MAT code associated with all MWC-2H work is 2H3, Valve Automation capital work. The Valve Automation capital work associated with StanPac facilities is included in MWC-44A with the same MAT code as the MWC.

Category MWC-KE includes all expenses associated with the Valve Automation Program development, the SCADA enhancement projects and

Valve Automation training development projects, as well as the reoccurring incremental maintenance and operating costs resulting from the implementation of the Valve Automation Program. The MAT code associated with all of this work is KE4, Station Other, except for the Program development costs which are included under MAT code KEX, Pipeline Other.

Detailed information about the scope and estimated cost of individual projects within the Valve Automation Program is included in the Workpapers Supporting Chapter 4.

2. Forecast Capital Expenditures (Phase 1)

The following table outlines the Valve Automation Program capital expenditures forecast by year necessary to execute the Phase 1 scope of work.

TABLE 4-5
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
CAPITAL EXPENDITURES
$ IN MILLIONS (NOMINAL)

Line No.	MAT Work Category	2011(a)	2012	2013	2014	Total
1	MAT-2H3	$13.7	$37.5	$48.7	$26.0	$125.9
2	MAT-44A (StanPac)	–	2.0	4.6	–	6.6
3	Total	$13.7	$39.5	$53.3	$26.0	$132.5

(a) The capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

a. Valve Automation Projects

Eighty (80) separate valve automation projects will be implemented in Phase 1 within 11 geographical areas. The forecast capital expenditures by area and year are outlined in the following table:

TABLE 4-6
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
CAPITAL EXPENDITURES – WORK BY AREA
$ IN MILLIONS (NOMINAL)

Line No.	Geographical Area	2011(a)	2012	2013	2014	Total
1	SF Peninsula (Launch)	$13.3	$0.4	–	–	$13.7
2	SF Peninsula (Remainder)	0.3	25.6	$0.9	–	26.8
3	San Jose Area	–	4.2	3.3	–	7.5
4	Antioch to Richmond (PG&E)	–	2.9	8.3	–	11.3
5	Antioch to Richmond (SP)	–	1.9	4.6	–	6.6
6	Oakland to Fremont to Livermore	–	0.2	16.9	$0.5	17.7
7	Brentwood Area	–	–	6.8	0.6	7.4
8	Sacramento Area	–	–	2.9	4.2	7.1
9	Vallejo-Fairfield Area	–	–	3.0	5.7	8.7
10	Stockton-Modesto Area	–	–	0.9	6.6	7.4
11	Bakersfield Area	–	–	–	2.5	2.5
12	Eureka Area	–	–	–	0.9	0.9
13	Barstow Area	–	–	–	1.5	1.5
14	Total	$13.6	$35.4	$47.8	$22.5	$119.3

(a) The 2011 capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

b. Other Capital Projects

Other Phase 1 capital projects includes the installation of thirty (30) operational flow meters at various locations and the installation of remote valve position monitoring capability on approximately fifty (50) manually operated valves at various locations. The forecast cost by year of these installations is outlined in the following table:

TABLE 4-7
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM,
PHASE 1 (2011-2014)
CAPITAL EXPENDITURES – OTHER CAPITAL PROJECTS
$ IN MILLIONS (NOMINAL)

Line No.	Work Type	2011(a)	2012	2013	2014	Total
1	Flow Meter Installations	–	$3.9	$5.3	$3.3	$12.5
2	Valve Position Remote Monitoring	$0.1	0.2	0.2	0.2	0.7
3	Total	$0.1	$4.1	$5.5	$3.5	$13.2

(a) The 2011 capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

3. Forecast Expenses (Phase 1)

a. Valve Automation Program Development

Valve Automation Program development costs includes contractor and incremental PG&E labor costs to review industry practices on RCV/ASV usage and available technology for RCV/ASV implementation, perform benchmarking of domestic and international companies on RCV/ASV usage, evaluate firefighting capabilities and impacts of various intensity natural gas fueled fires, develop criteria for RCV/ASV usage for PG&E's gas transmission system, identify pipe segments meeting the developed criteria, develop a unit cost estimating methodology for segments to be automated, and evaluating and cost estimating Phase 1 pipe segments identified for automation.

The forecast cost by year for development of the Valve Automation Program, all of which is being incurred in 2011, is outlined in the following table:

TABLE 4-8
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
EXPENSE PROJECTS – PIPELINE OTHER
$ IN MILLIONS (NOMINAL)

Line No.	MAT Work Category	2011(a)	2012	2013	2014	Total
1	Pipeline Other, MAT-KEX	$0.8	–	–	–	$0.8

(a) The 2011 expenses will be funded by shareholders, as described in Chapter 8.

b. SCADA Enhancements and Valve Automation Expense Projects

SCADA enhancement and valve automation expense projects 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. The forecast cost by year for implementation of these projects is outlined in the following table:

TABLE 4-9
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
EXPENSE PROJECTS – STATION OTHER
$ IN MILLIONS (NOMINAL)

Line No.	MAT Work Category	2011(a)	2012	2013	2014	Total
1	Station Other, MAT-KE4	$0.8	$1.8	$1.8	$2.2	$6.6

(a) The 2011 expenses will be funded by shareholders, as described in Chapter 8.

c. Reoccurring Operations and Maintenance Costs (M&C, Gas Control)

The implementation of the various capital and expense projects will result in additional ongoing Operations and Maintenance (O&M) expense. This includes increased O&M costs for maintenance, inspection, testing and system monitoring and operations. The forecast cost by year for these annually reoccurring costs during the Phase 1 time period of 2011-2014 is outlined in the following table:

TABLE 4-10
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
REOCCURRING O&M EXPENSES – STATION OTHER
$ IN MILLIONS(NOMINAL)

Line No.	MAT Work Category	2011(a)	2012	2013	2014	Total
1	Station Other, MAT-KE4	–	$0.8	$1.3	$1.6	$3.7

(a) The 2011 expenses will be funded by shareholders, as described in Chapter 8.

K. Project Implementation (Phase 1)

1. Scheduling of Work

PG&E expects to complete approximately 80 separate valve automation projects, as well as a project to install additional flow metering, during Phase 1. PG&E has created a proposed preliminary schedule for work execution. This schedule and future modifications are based upon the following considerations:

- Population density and concentration of high PIR pipelines.

- Minimization of operational impact to the gas transmission system and service impacts to customers.
- Value and work efficiencies of coordinating work together by pipeline and geographical area.
- Coordination with other scheduled pipeline work including pipe replacements, station rebuilds, ILI, and strength testing of pipeline segments.

The flow metering installations will be implemented in conjunction with the valve automation work planned for specific pipelines and station facilities.

2. Implementation Schedule

Engineering of an early launch of Phase 1 valve automation projects is underway with construction scheduled for the second half of 2011. Executing this set of eight projects on the San Francisco Peninsula will provide us with knowledge to fine tune our implementation plan to optimize work execution. After the early launch set of projects, current plans are for beginning engineering on nine projects each quarter beginning in the second half of 2011, with each project then having a 15-month duration to engineer, construct, and place into operation. The following table provides the planned start and operative dates for the eighty (80) valve automation projects by geographical area:

TABLE 4-11
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM, PHASE 1 (2011-2014)
WORK EXECUTION BY AREA

Line No.	Geographical Area	Start	Operational Date	Total Projects
1	Peninsula (2011 Construction)	2011	2011	8
2	Peninsula (2012 Construction)	2011	2012	14
3	San Jose Area	2011 & 2012	2012 & 2013	7
4	Antioch to Richmond	2012	2013	11
5	Oakland to Fremont to Livermore	2012	2013	13
6	Brentwood Area	2012	2013	4
7	Sacramento Area	2013	2014	4
8	Vallejo-Fairfield Area	2013	2014	5
9	Stockton-Modesto Area	2013	2014	7
10	Bakersfield Area	2013	2014	3
11	Eureka Area	2013	2014	2
12	Barstow Area	2013	2014	2

All Phase 1 Valve Automation work is forecasted to be complete by the end of 2014. Phase 2 projects are planned to begin engineering during 2014.

3. Need for Plan Modifications and Work Re-Prioritization

The Valve Automation Program will evaluate changes to class location and HCA of pipe segments as new information becomes available to identify potential changes to the initial list of pipe segments included in the plan for automation. The total number of valves requiring automation and those requiring replacement may require adjustment as detailed engineering is completed on specific projects. Any adjustments should be only minor in nature.

Work will be closely coordinated with other capital and expense budgeted work both within the GT&S rate case and within other parts of the Implementation Plan. If plans for other work changes or new projects are added, the Valve Automation Program will adjust its work plan to effectively and efficiently manage the program.

Program changes will be recorded and reported to the CPUC bi-annually.

4. Quality Assurance and Quality Control

All PG&E gas transmission labor, construction, and materials procurement work is performed to the highest quality and sound professional procedures and practices, and in conformance with all PG&E Gas Standards and Work Procedures, U.S. DOT regulation 49 CFR Part 192, including DOT operator qualifications and drug and alcohol testing, API 1104 and 5L standards, Occupational Safety and Health Administration (OSHA) and California OSHA (Cal-OSHA) requirements, and any federal, state and local laws, rules, regulations and ordinances.

To ensure work quality, PG&E is instituting a Quality Assurance and Quality Control (QA/QC) program to oversee construction activities for Implementation Plan projects. This QA/QC program will be similar to the new QA/QC program PG&E developed for gas transmission pipeline construction.

Quality Assurance is the means of assuring that the QC methods PG&E employs are effective in ensuring compliance with all applicable design standards. The QA team monitors construction activities on pre-determined sampling frequencies, making adjustments to the frequencies as needed based on gathered results.

Quality Control refers to the operational activities put in place to control the quality of a product or service, and is further defined as the routine and systematic inspections conducted to verify that each phase of the work meets or exceeds the minimum design requirements. The QC activities/processes will be consistently monitored by QC inspectors capable of ensuring the work is being done in accordance with the drawings and applicable standards.

L. Conclusion

In summary, the capital expenditures and expenses presented in this chapter will allow PG&E to provide automated isolation capability for all large diameter, high pressure, gas transmission pipelines in Class 3 HCA areas and all gas transmission pipelines in Class 4 areas. The expenditures also allow PG&E to provide automatic shut-off capability on large diameter, high pressure, pipelines in populated areas that cross active earthquake faults that represent a rupture threat to these lines. Additionally, the expenditures allow PG&E to enhance its SCADA system and Gas Control operations to provide additional tools and training for minimizing the time to detect and respond to a pipeline rupture. PG&E believes that the forecasted capital expenditures and expenses contained herein are reasonable, prudent, and should be approved by the CPUC for implementation and cost recovery. Implementation of the Valve Automation Program will facilitate emergency response in the event of a pipeline rupture, thereby reducing potential threat and the impact on the public and property.