PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

GAS TRANSMISSION VALVE AUTOMATION PROGRAM

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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

[1] "Blowdown" is the process where gas in the pipeline is evacuated until the 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 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

gas pressure reaches atmospheric pressure.

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

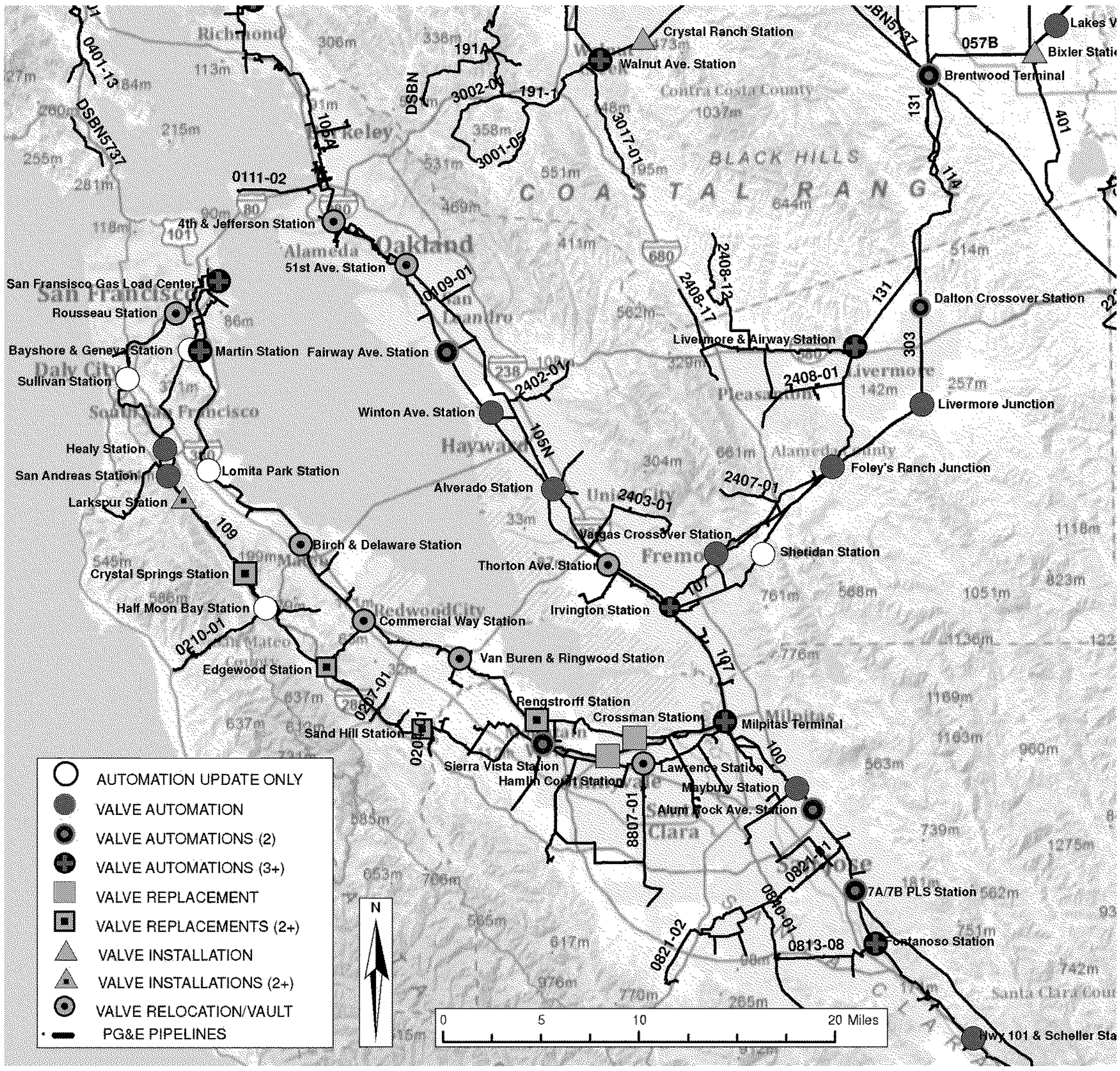
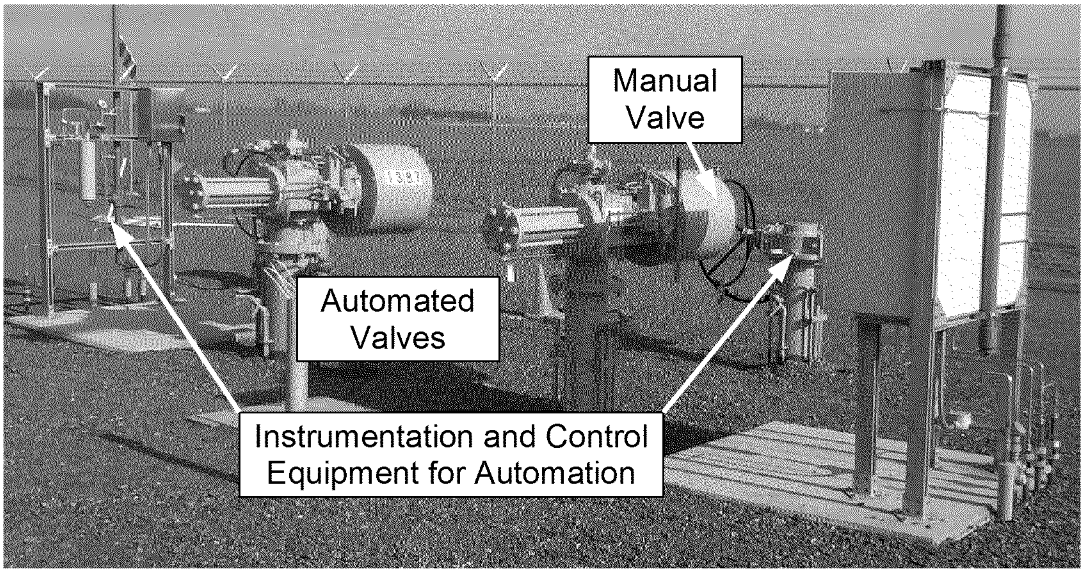


Figure 4-2 illustrates a typical pipeline station facility containing both manual and automated valves. The photo shows two automated and one manual valve, and the instrumentation and controls for the automated valves.

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 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

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

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.
- 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.

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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 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

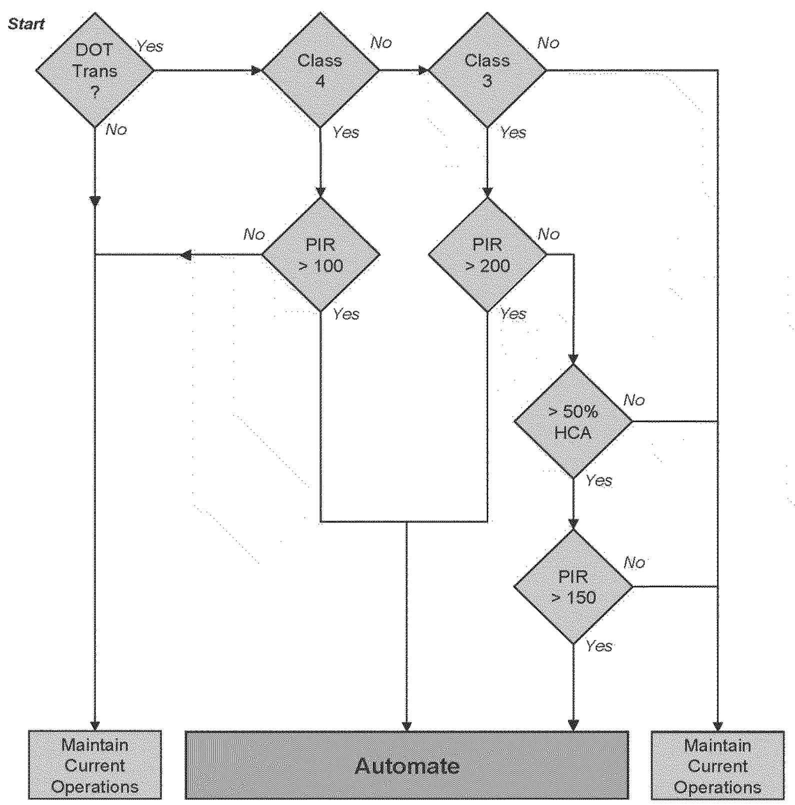
PG&E has created two decision trees, one based on population density and the other based on earthquake fault crossings, to assist the Company's engineers in determining which pipe segments should be equipped with automated isolation capability as part of the full Valve Automation Program (Phases 1 and 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.

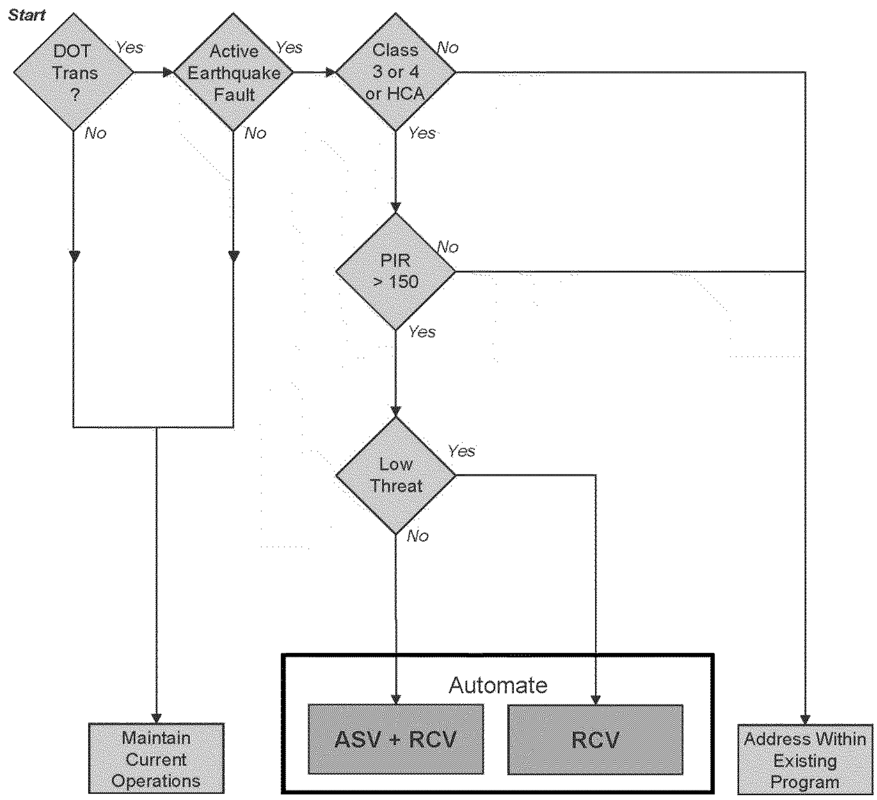
FIGURE 4-3
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – POPULATION DENSITY



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.

y onto an ignited natural gas flame, minimizing the effects of