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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

NOTICE OF FILING AND REQUEST FOR APPROVAL OF SOUTHWEST GAS CORPORATION'S (U 905 G) NATURAL GAS TRANSMISSION PIPELINE COMPREHENSIVE PRESSURE TESTING IMPLEMENTATION PLAN

SOUTHWEST GAS CORPORATION
Justin Lee Brown, Esq.
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Telephone No. (702) 876-7183
Facsimile No. (702) 252-7283
E-mail: justin.brown@swgas.com

Attorney for Southwest Gas Corporation

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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Introduction and Brief Background

1. Southwest Gas Corporation (Southwest Gas) respectfully submits its request for approval of its Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the California Public Utility Commission's (Commission) issued Decision (D.)11-06-017, requiring all natural gas transmission system operators to file and serve orderly and cost-conscience implementation plans to pressure test or replace all transmission pipeline that have not been pressure tested.

2. Southwest Gas is a corporation duly organized and validly existing under the laws of the state of California, is qualified to transact intrastate business and is in good standing under the laws of the state of California. Southwest Gas is engaged in the retail transmission, distribution, transportation, and sale of natural gas for domestic, commercial, agricultural, and industrial uses to approximately 1.8 million customers in the states of California, Arizona, and Nevada.

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3. Southwest Gas Corporation is the exact name of the corporation, the principal place of business is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002 and the telephone number is (702) 876-7011.

4. Consistent with Rule 1.10, Southwest Gas agrees to accept electronic mail service of all notices, filings and submittals from the Commission and all parties granted leave to participate in this proceeding. Communications regarding this filing should be addressed to:

Justin Lee Brown, Esq.
Assistant General Counsel
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Telephone No. (702) 876-7183
Facsimile No. (702) 252-7283
E-mail: justin.brown@swgas.com

Christy Berger
Manager/State Regulatory Affairs
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Telephone No. (702) 364-3267
Facsimile No. (702) 873-3820
E-mail: christy.berger@swgas.com

5. On June 16, 2011 the Commission issued D.11-06-017 requiring all natural gas transmission pipeline operators be required to prepare and file a comprehensive implementation plan to pressure test or replace all natural gas transmission pipeline in California that have not been pressure tested. The implementation plans are required to be filed no later than August 26, 2011. Southwest Gas' proposed Implementation Plan is attached hereto as Exhibit A.

Proposed Implementation Plan

6. Southwest Gas maintains approximately 15.4 miles of pipeline classified as transmission in California. Excluding Tap inlet piping, the overall transmission system can be broken down into two systems: The Victor Valley Transmission System and the Harper Lake Transmission System. The Victor Valley Transmission System contains

approximately 7.1 miles of 6” and 8” steel pipe installed in 1957 and 1965, and pressure test records are not readily available. The Harper Lake Transmission System contains approximately 8.3 miles of 10”, 12” and 16” steel pipe installed in 1989 that was pressure tested at time of installation and has pressure test records.

7. After analysis and comparison of the pipeline pressure testing and pipeline replacement alternatives, Southwest Gas proposes to abandon the pipeline and install new pipe over an 18-24 month period following Commission approval of the proposed Implementation Plan. This analysis and comparison of alternatives is further detailed in the Implementation Plan attached hereto as Exhibit A and the prepared direct testimony of Lynn A. Malloy.

8. Southwest Gas proposes to prioritize the pipe replacement to make the largest positive impact to public safety and system integrity by replacing the 1.33 miles of High Consequence Areas first. Southwest Gas proposes to then replace the remaining approximately 5.77 miles of transmission pipeline, all of which are primarily located in Class 3 locations.

9. Southwest Gas submits that the Harper Lake Transmission System is currently fully-capable of accommodating in-line inspection tools (with the exception of launchers and receivers). The replacement pipeline for the Victor Valley Transmission System will be designed to accommodate in-line inspection tools (with the exception of launchers and receivers).

10. In addition, following its review of the respective geographic locations and the potential response times for personnel to respond to an incident involving the Victor Valley Transmission System or Harper Lake Transmission System, Southwest Gas proposes to

install a remote control shut off valve on the Harper Lake Transmission System. Southwest Gas submits that the installation of remote shut off valves on the Victor Valley Transmission System is not warranted at this time.

11. Southwest Gas anticipates that the proposed construction activities associated with its Implementation Plan will be completed prior to Southwest Gas' next general rate case filing, expected to be filed late 2012 with a 2014 test year. The total cost associated with the proposed Implementation Plan is approximately $7.4 million. Therefore, rather than establishing an interim surcharge to recover the costs associated with the Implementation Plan, Southwest Gas proposes to establish a deferred regulatory asset account to defer the depreciation expense, carrying charges and property taxes associated with the Implementation Plan until new rates are established in the rate case.

12. Depreciation expense will be calculated using the currently authorized depreciation rates, carrying charges will be based on the currently authorized cost of capital and property taxes will be calculated using the Company's current property tax rate. The deferred asset account will be amortized over the rate case cycle, typically three to five years, and the depreciated capital costs associated with the Implementation Plan will be incorporated into the development of the test year rate base. Additionally, ongoing expenses related to the Implementation Plan will be included in the development of the test year revenue requirement in the Company's next general rate case.

13. Since the Company is not proposing to adjust rates as part of its Implementation Plan, there will be no immediate impact to customer rates following Commission approval of the proposed Implementation Plan. Rather, rates will not be adjusted until the Commission issues an order following the Company's next general rate

case. Notwithstanding, the estimated annual revenue requirement associated with the Implementation Plan is approximately $1,500,000. Although the impact to each customer class will ultimately be a function of the approved class-cost-of-service study and the resultant revenue requirement spread, on average the effect on customer rates would be $0.016 per therm. For an average residential customer, the bill impact is anticipated to be approximately $0.72 per month. The estimated proposed rate impacts for each customer class are further detailed in the Implementation Plan attached hereto as Exhibit A and the prepared direct testimony of Edward Gieseking.

Summary and Conclusion

14. Based upon the foregoing, Southwest Gas requests the Commission approve the Implementation Plan attached hereto, drafted in compliance with Commission Decision 11-06-017, and grant such further relief as the Commission deems appropriate.

Dated this 26th day of August, 2011, at Las Vegas, Nevada.

Respectfully submitted by,
SOUTHWEST GAS CORPORATION

/s/ Justin Lee Brown

Justin Lee Brown, Esq.
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Telephone No. (702) 876-7183
Facsimile No. (702) 252-7283
E-mail: justin.brown@swgas.com

Attorney for Southwest Gas Corporation

Exhibit A

SOUTHWEST GAS CORPORATION

Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan

Pursuant to Rulemaking 11-02-019

8/26/2011

INTRODUCTION

As part of Order Instituting Rulemaking 11-02-019, the California Public Utilities Commission (Commission) issued Decision 11-06-017 (Order) ordering all California natural gas transmission operators to submit a Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) for Commission consideration. The stated goal of the Order is to orderly and cost effectively replace or pressure test all natural gas transmission pipelines that have not been pressure tested in accordance with 49 CFR 192.619.

1 IMPLEMENTATION PLAN OVERVIEW

Southwest Gas Corporation (or the Company) evaluated the transmission pipeline in its California service territory and determined which segments of pipe did not meet the pressure testing requirements of the Order and the necessary measures to comply with the Order. The Company's proposed Implementation Plan is outlined in the following sections:

- Section 1: Implementation Plan Overview
- Section 2: Pipeline System Overview
- Section 3: Decision Analysis
- Section 4: Pipeline Replacement Program
- Section 5: Pressure Testing and MAOP Records
- Section 6: Interim Safety Enhancement Measures
- Section 7: Shut Off Valves and In-line Inspection Tools
- Section 8: Implementation Plan Cost Estimate
- Section 9: Cost Allocation and Rates
- Section 10: Implementation Plan Summary

2 PIPELINE SYSTEM OVERVIEW

Transmission pipeline is characterized as operating at a hoop stress of 20% or more of Specified Minimum Yield Strength (SMYS). Hoop stress of the pipe is calculated by a relation of the Maximum Operating Pressure (MOP) to the wall thickness and diameter.

Southwest Gas maintains approximately 15.4 miles of pipeline classified as transmission in California. Excluding Tap inlet piping, the overall transmission system consists of two systems (shown in Figure 1): The Victor Valley Transmission System and the Harper Lake Transmission System.

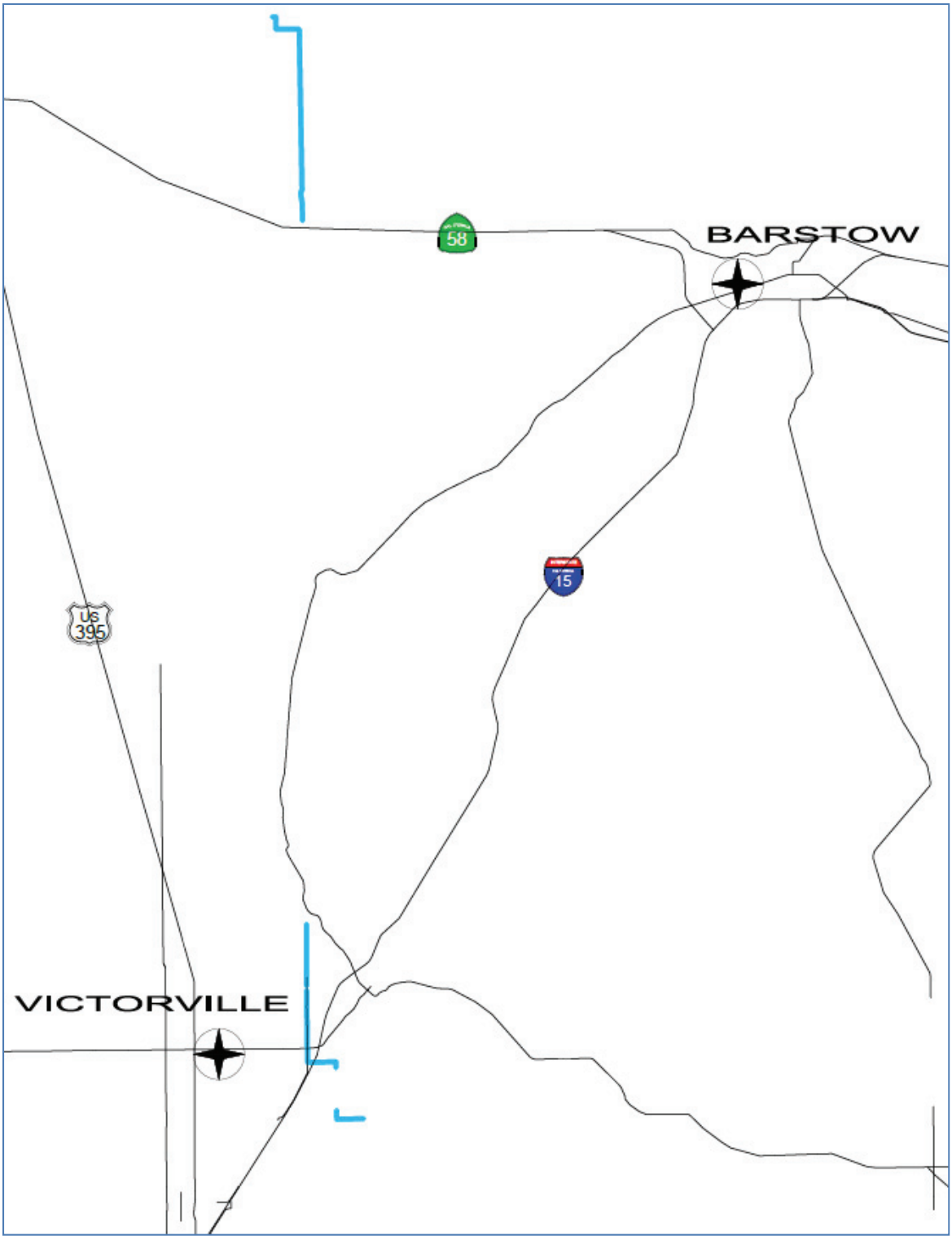

Figure 1: Southwest Gas California Transmission Map. The Victor Valley Transmission System is shown in blue on the lower-end of the map; the Harper Lake Transmission System is shown in blue on the upper-end of the map.

2.1 VICTOR VALLEY TRANSMISSION SYSTEM

The Victor Valley Transmission System contains approximately 7.1 miles of 6" and 8" steel pipe installed in 1957 and 1965 and has no readily available pressure test records. When the federal pipeline safety regulations came into effect in 1970, a Maximum Allowable Operating Pressure (MAOP) of 175 psig was established using the 5-year historical operating pressure as allowed under section 49 CFR 192.619 (c). In 1973, the system was uprated to a MAOP of 250 psig in accordance with 49 CFR 192 Subpart K (uprating) that was in effect at the time. Subpart K allowed an operator to uprate the system without a 1.5 times MAOP pressure test (associated with a class 3 location). The MOP of the system is 240 psig. The Victor Valley Transmission System operates primarily in a Class 3 Location (approximately 2,175 feet operate in a Class 1 Location) and the characteristics of the system are detailed in Table 1.

Table 1 – Victor Valley Transmission System Characteristics

Transmission System	Date Installed	Length (feet)	O.D. (in)	Wall Thick. (in)	Pipe Spec.	SMYS (psi)	Class Loc. No.
Victor Valley	Dec-57	34450	8.625	0.188	Minimum	24000	3
	Dec-57	875	6.625	0.148	Minimum	24000	3
	Jan-65	2175	6.625	0.148	Minimum	24000	1

Transmission System	Design Factor	Long. Factor	Design Pressure (psi)	Segment MAOP (psi)	System MAOP (psi)	System MOP (psi)	Hoop Stress at System MOP	Hoop Stress at Segment MAOP
Victor Valley	0.5	0.8	419	250	250	240	23%	24%
	0.5	0.8	429	250	250	240	22%	23%
	0.5	0.8	429	250	250	240	22%	23%

The Victor Valley Transmission System operates at an operating stress level of 23% of SMYS. Pipe wall thickness values are based on the minimum industry standards available during the installation period; actual specifications are unknown. Pipe SMYS values are based on 49 CFR Part 192.107 (b.2), which specifies a minimum value of 24,000 psig may be used.

Because there are no readily available records of a 1.5 MAOP pressure test, the Victor Valley Transmission System will be considered in this

Implementation Plan for pipeline pressure testing or replacement to comply with the Order.

Also included in this report is an evaluation of the Victor Valley Transmission System's ability to accept in-line inspection tools and to consider the placement of shut off valves.

2.2 HARPER LAKE TRANSMISSION SYSTEM

The Harper Lake Transmission System contains approximately 8.3 miles of 10", 12" and 16" steel pipe installed in 1989 that was pressure tested at the time of installation under the requirements of 49 CFR 192 Subpart J and has readily available pressure test records. The Harper Lake Transmission System has a MOP of 550 psig and operates at an operating stress level of 39% of SMYS, with a MAOP of 720 psig (50% of SMYS). Because the Harper Lake Transmission System complies with the pressure test requirements of the Order, the focus of the Implementation Plan regarding this system is in the ability to accept in-line inspection tools and to consider placement of shut off valves. The Harper Lake Transmission System operates primarily in a Class 1 Location (approximately 4,000 ft operate in a Class 3 Location).

3 DECISION ANALYSIS

The majority of the pipe in the Victor Valley Transmission System was installed in the same year, has similar pipeline characteristics and threats (i.e. corrosion, excavation/third party damage), and is located in the same geographical area. As such, in deciding how to meet the pressure testing requirements of the Order, the decision analysis was applied to the entire system versus each segment of pipe within the system. Therefore, the decision would apply to all pipe segments within the Victor Valley Transmission System.

The decision analysis included the following steps:

1. Establish the objectives for evaluating alternatives (i.e. options) to meet the requirements of the Order.
2. Identify and evaluate the alternatives.
3. Select the best alternatives based on established objectives, as well as risks and potential problems associated with the alternatives.
4. Prioritize the segments to be pressure tested or replaced.

3.1 OBJECTIVES

The key objectives on which the options were evaluated are as follows:

- Must meet the requirements of the Order
- Must improve integrity and safety of transmission pipe
- Must be capable of accepting in-line inspection tools
- Should minimize service interruption to customers
- Should be cost effective in relation to benefits provided

3.2 IDENTIFY AND EVALUATE ALTERNATIVES

The main alternatives considered were as follows:

1. *Pressure test pipe.* Perform a 1.575 times MAOP pressure test.
2. *Replace.* Abandon existing pipe and install new pipe.
3. *Reduce system pressure.* Reduce system pressure to account for the 1.575 times test (includes 5% spike test) or to reduce operating stress level to that of distribution classification levels (versus transmission classification).

Reducing system pressure was eliminated as a viable alternative, as the reduced pressure would not meet existing or future gas load (i.e. customer use) requirements. In addition, simply reducing system pressure will not address questions about the existing pipe with regards to pipe yield strength and wall thickness.

Pressure Testing

Pressure testing the pipe poses the following challenges:

- *Material specifications.* Various fittings connected to the pipeline have an acceptable rating for the current MAOP. Verifying if they are rated to withstand a 1.575 times pressure test may present a significant challenge. In addition, even with a pressure test, the material specifications of the pipe are still unknown. Absent the material specifications, the records may not be considered "traceable, verifiable, and complete." Additional costs will be associated with determining the material specifications of the pipeline through approximately 200 test coupons required to be cut-out of the existing pipe (required by 49 CFR Part 192).
- *Unknown Fittings:* There are an estimated 50 lateral pipelines in the system, stemming from old regulator station and farm tap points that are capped off. Those would need to be replaced in order to perform a 1.575 MAOP pressure test. In addition, the possibility of unknown lateral pipelines exists.
- *Testing Complications.* Certain segments of existing pipe would require modification to ensure areas of water accumulation (i.e. low points) are removed.
    - Modifications would be necessary prior to testing to ensure that de-watering pigs can be accommodated
    - Pressure testing (even without other complications) will lead to some customer constraints, and scheduling with customer needs may delay the compliance with the Order
    - Use of water introduces a potential risk of internal corrosion if water is not removed properly
    - Use of water introduces a potential risk for pressure regulators to freeze-up if water is not removed properly

  - If leaks are identified during the pressure test, determining the location and repairing the leak may cause significant customer interruptions
  - Environmental permits/approvals may be challenging when considering disposing of water used for testing
- *Pipeline Threats.* While pressure testing will likely identify existing manufacturing and construction defects and some corrosion defects that are triggered due to stresses related to the test pressure, it may not identify other threats such as mechanical damage and girth weld defects that would only surface if stressed to higher levels than the resulting stresses from the pressure test
- *Unable to accept ILI tools: Pressure testing would not lead to modifications to make the line capable of "smart-pigging".*

Pressure testing the pipe poses the following benefits:

- Potential lower cost than replacement

The cost estimate for pressure testing the 7.1 miles of pipe in the Victor Valley Transmission System, assuming no leaks are identified, is approximately $1.5 million. Performing material specification testing is estimated at approximately $2 million. Performing pipe section replacement for an estimated 50 sections of pipeline laterals is estimated at approximately $250,000. Considering each of these components, the minimum cost estimate for the pressure testing alternative is approximately $3.75 million.

While the estimated costs of this alternative are approximately $3.75 million, if the pipeline fails the 1.575 MAOP pressure test, additional costs of approximately $1 million per mile would be incurred to identify and replace the sections of pipe that caused the failed test.

<u>Pipeline Replacement</u>

Pipeline replacement poses the following challenges:

- Potential higher cost than pressure testing
    - The cost estimate for replacing the 7.1 miles of pipe in the Victor Valley Transmission System is approximately $7.1 million. While this cost estimate is higher than the cost estimate for pressure testing, it is an estimated cost based upon certain expectations, whereas the pressure testing cost could vary significantly and not meet the expectations.

Pipeline replacement poses the following benefits:

- Less risks and challenges when conducting new installation pressure test
- Provides capability of accommodating in-line inspection tools
- Provides traceable, verifiable, and complete records
- Establishes a reduced operating stress level to classify pipe as distribution versus transmission
- X-ray verification and documentation of weld integrity
- Modern day installation practices
- Documentation of pipeline specifications
- No customer outage or minimal customer outage

3.3 SELECTING THE BEST ALTERNATIVE

Based on the evaluation of the alternatives, replacing the existing pipe with new pipe was determined to be the best option. Though the pressure testing may be less costly than replacing pipe, potential leaks by subjecting the pipe to a 1.575 times pressure test could increase the overall costs and customer constraints substantially.

The potential for significant additional costs, in combination with other complications discussed in section 3.2, are key factors in the decision to replace the pipe in the Victor Valley Transmission System. Furthermore, installing new pipe is the best way to ensure public safety by mitigating risk

and increasing the integrity of the pipeline. Pipeline integrity is increased by reducing operating stress level, having pipe with known material specifications and pressure test records, utilizing modern materials and modern design and installation procedures and having the capacity for future assessment options including in-line inspections are all beneficial to customers.

4 PIPELINE REPLACEMENT PROGRAM

As described in Section 3, Southwest Gas proposes to abandon the pipe in the Victor Valley Transmission System and install new pipe. Southwest Gas has been proactively planning and instituting transmission reduction projects in the Victor Valley Transmission System for several years and is experienced in successfully replacing pipeline segments with minimal customer interruptions.

The Victor Valley System contains 7.1 miles of transmission pipeline that will be replaced over an 18-24 month period beginning in 2012.

The new pipe installed will be 8.625", 0.322" wall thickness, X-52 (52,000 SMYS) coated steel pipe. This pipe type is consistent with the type of pipe being used for steel replacement projects at Southwest Gas. The current cathodic protection system will be utilized to protect the pipeline.

4.1 REPLACEMENT SCHEDULE

The goal of the first year of the pipe replacement program is to make the largest positive impact to public safety and system integrity. The areas of transmission pipeline within the greatest percentage of population and businesses are the first priority for replacement.

As previously discussed, there are currently 1.33 miles transmission pipe located in High Consequence Areas (HCAs) within the Southwest Gas transmission system in California, all of which are in the Victor Valley Transmission System. Using the strategy of replacing pipe located within the

greatest percentage of population and businesses will allow Southwest Gas to eliminate all 1.33 miles of HCAs.

Through this replacement, the HCA designation will be eliminated because the new pipe being installed has known material specifications and a 1.5 MAOP pressure test, and will be classified as distribution pipeline. The pipeline will then be reviewed as part of the Distribution Integrity Management Program (DIMP).

The proposed replacement schedule consists of Priority One and Priority Two projects that together will be completed over an 18-24 month period. Permitting issues, both with local government agency and environmental, along with material availability and availability of qualified construction personnel could affect the timeline. The schedule will be implemented following Commission approval of the Implementation Plan (estimated Q4 2011).

The Priority One schedule will replace approximately 3.1 miles of transmission pipeline, all in Class 3 locations and containing the 1.33 miles of HCAs. Figure 2 shows a map of the pipeline with the first priority for scheduled replacement. The Priority Two schedule will replace approximately 4.0 miles of transmission pipeline, in Class 3 and Class 1 Locations with no existing HCAs. Figure 3 shows a map of the pipeline with the second priority for scheduled replacement.

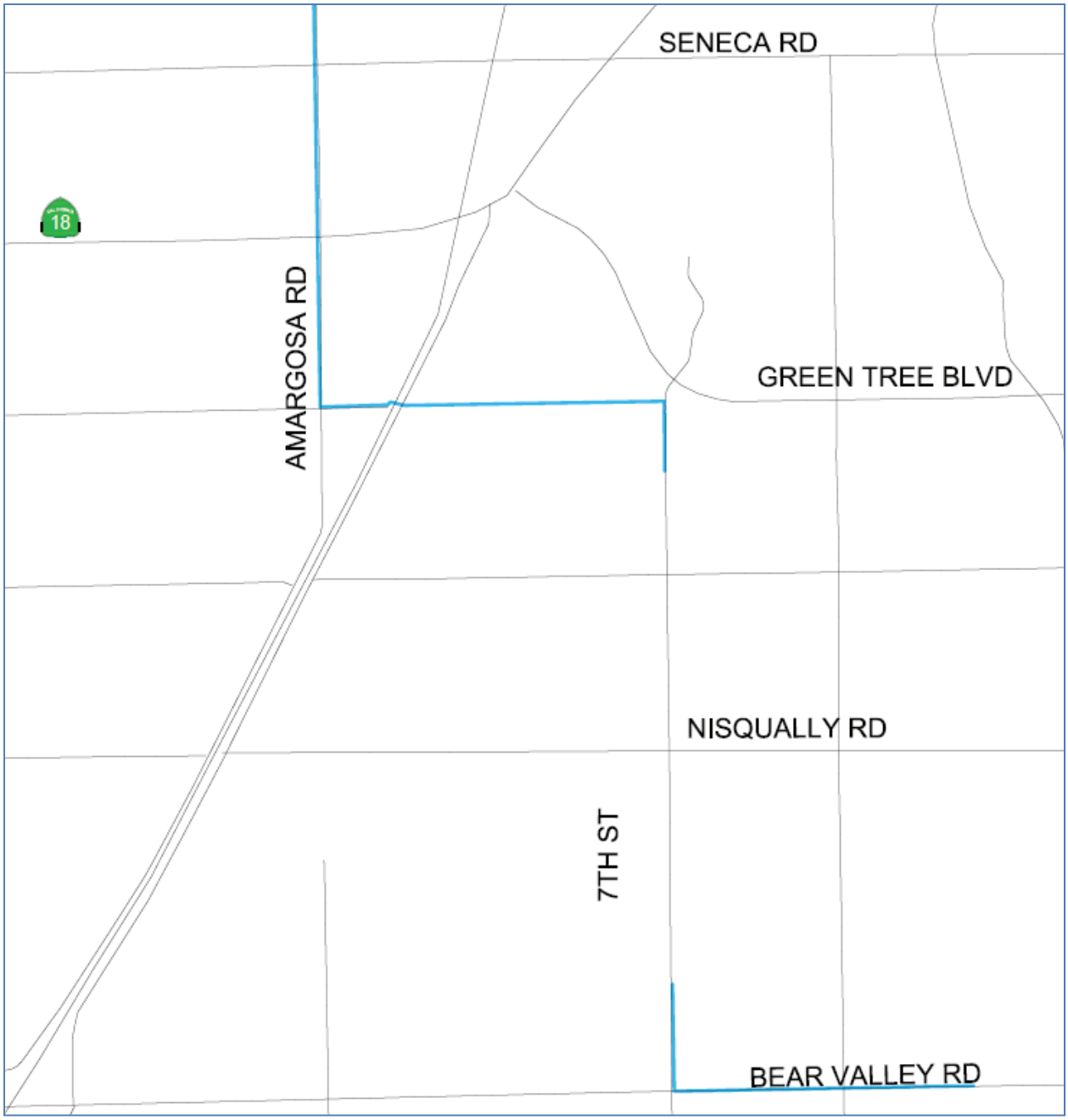

Figure 2: Victor Valley Transmission System Pipeline Replacement Map depicting pipeline (blue) with first priority for replacement.

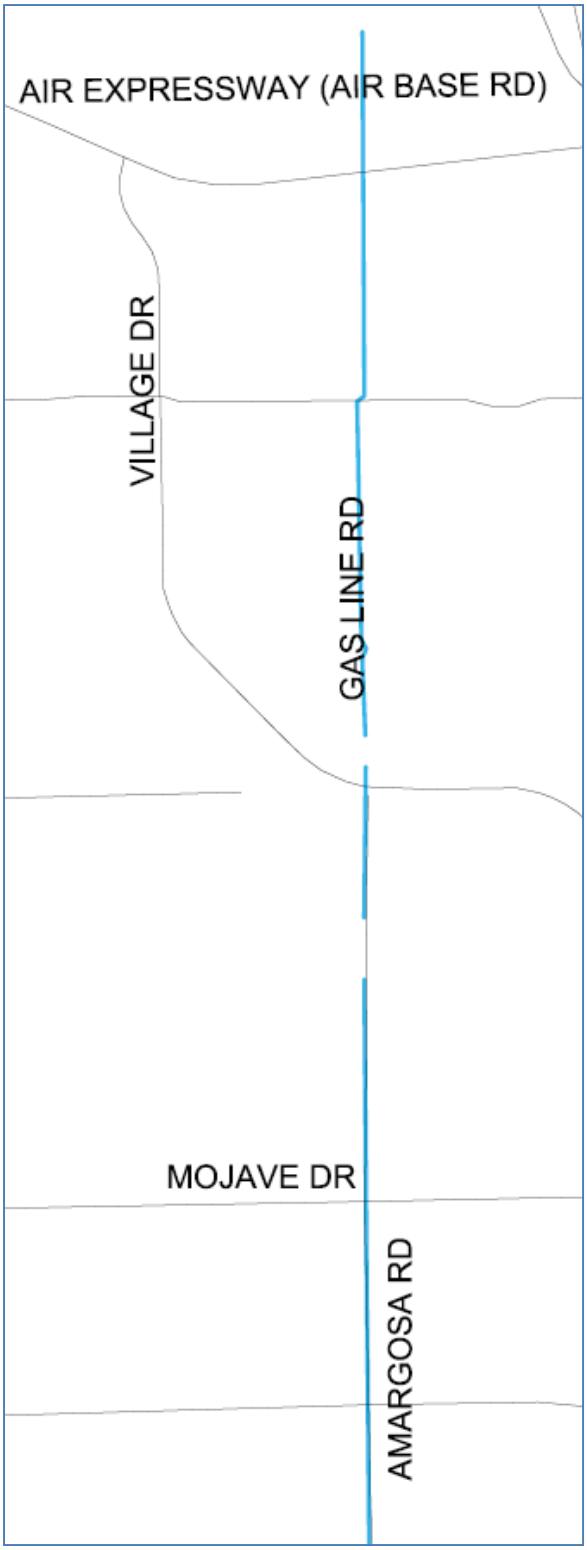

Figure 3: Victor Valley Transmission System Pipeline Replacement Map depicting pipeline (blue) with second priority for replacement.

5 PRESSURE TESTING AND MAOP RECORDS

All of the new pipeline in the Victor Valley System will be pressure tested prior to being placed in service in compliance with 49 CFR 192 Subpart J. As described in previous sections, the Victor Valley System is in a Class 3 Location, and will be tested to 1.5 times MAOP.

As shown in Table 2, in order to establish a MAOP of 720 psig, the pipeline pressure test must be 1080 psig (1.5 times MAOP). While the segment will have a MAOP of 720 psig, the system itself will maintain a MAOP of 250 psig and a MOP of 240 psig in order to remain compatible with the associated high-pressure distribution systems that feed the distribution systems in the service area. The Victor Valley System will operate at an operating stress level of 6% of SMYS. This represents a large reduction of operating stress level and enhances safety to the public and pipeline system integrity.

All of the pipeline in the Victor Valley System will have readily available pressure test records.

Table 2: Projected MAOP Record of Victor Valley System after Implementation Plan

Transmission System	Date Installed	Length (feet)	O.D. (in)	Wall Thick. (in)	Pipe Spec.	SMYS (psi)	Class Loc. No.	Pressure Testing	
								Factor	(psi)
Victor Valley	2012-2013	35325	8.625	0.322	X52	52000	3	1.5	1080
	2012-2013	2175	8.625	0.322	X52	52000	1	1.1	1080

Transmission System	Design Factor	Long. Factor	Design Pressure (psi)	Test MAOP (psi)	Segment MAOP (psi)	System MAOP (psi)	System MOP (psi)	Hoop Stress at System MOP	Hoop Stress at Segment MAOP
Victor Valley	0.5	1	1941	720	720	250	240	6%	19%
	0.72	1	2796	720	720	250	240	6%	19%

6 INTERIM SAFETY ENHANCEMENT MEASURES

As noted earlier, the Victor Valley Transmission System has operated safely for over 54 years and operates at 23% hoop stress as a percentage of SMYS. Reducing system pressure while the replacement plan is being implemented was

ruled out because the current gas load (customer use) requirements cannot be sustained under a pressure reduction scenario. Southwest Gas therefore plans to double the amount of leak surveys and patrols required by 49 CFR Part 192 until the pipeline is replaced.

7 SHUT OFF VALVES AND IN-LINE INSPECTION TOOLS

The Implementation Plan calls for natural gas operators to consider retrofitting transmission pipeline to allow for in-line inspection tools and, where appropriate, improved shut off valves.

The new pipeline that will be installed in the Victor Valley System will be designed to accommodate in-line inspection tools (with the exception of launchers and receivers). While the low operating pressure of the system can make it challenging for current pigging technology to be effective, the fittings in the system will allow emerging self-powered in-line inspection robot technology to effectively navigate the system.

Southwest Gas analyzed if it was appropriate to install remote shut off valves in the Victor Valley System. This analysis showed that in the event of an incident, the manual shut off valves could be engaged in less than 25 minutes in any part of the system. Furthermore, given the enhanced safety of replacing the Victor Valley Transmission System with a distribution system combined with the accessibility to manually operate valves in less than 25 minutes along any part of the pipeline has led Southwest Gas to conclude that the installation of such valves is not warranted at this time. Using manual shut off valves, compared to remote shut off valves, will reduce overall pipeline replacement costs while still providing a high level of safety to the public.

The Harper Lake Transmission System primarily feeds several solar energy production plants. Unlike the Victor Valley System, the Harper Lake Transmission System is in the northwest corner of Southwest Gas' service territory and could take up to 60 minutes for personnel to respond to an incident. Southwest Gas believes

the installation of a remote control shut off valve in the Harper Lake Transmission System is warranted to minimize the required time to react to a potentially unanticipated release of gas and to fully shut off natural gas flow to the system to ensure customer safety.

The Harper Lake Transmission System is currently fully-capable of accommodating in-line inspection tools (with the exception of launchers and receivers). Figure 4 shows an overview map of the Harper Lake Transmission System.

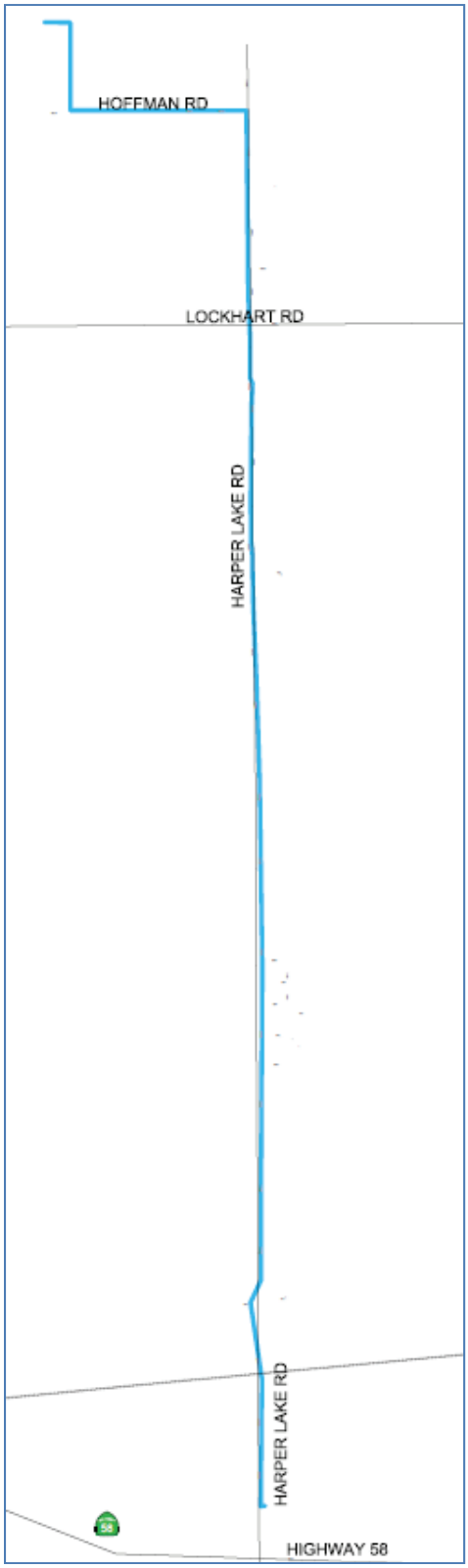

Figure 4: Harper Lake Transmission System (blue) Overview Map

8 IMPLEMENTATION PLAN COST ESTIMATE

The cost estimate for the proposed Implementation Plan is $7,400,000. The pipeline replacement program for the Victor Valley Transmission System is based on historical values of replacement projects. The installation of a remote shut off valve for the Harper Lake Transmission System is based on industry standard cost estimates.

- Approximately 7.1 miles of replacement, estimated at $7,150,000:
  - Priority One: 3.1 miles at $3,100,000
  - Priority Two: 4.0 miles at $4,050,000
- Automatic Remote Control Valve Installation estimated at $250,000:
  - Priority Two: One remote control valve at $250,000

9 COST ALLOCATION AND RATES

The Implementation Plan construction activities will be completed prior to the Company's next general rate case filing, expected to be filed late 2012 with a 2014 test year. Therefore, rather than establishing an interim surcharge to recover the costs associated with the Implementation Plan, Southwest Gas proposes to establish a deferred regulatory asset account to defer the depreciation expense, carrying charges and property taxes associated with the Implementation Plan until new rates are established in the Company's next general rate case. Depreciation expense will be calculated using the currently authorized depreciation rates, carrying charges will be based on the currently authorized cost of capital and property taxes will be calculated using the Company's current property tax rate. The deferred asset account will be amortized over the rate case cycle, typically three to five years, and the depreciated capital costs associated with the Implementation Plan will be incorporated into the development of the test year rate base. Additionally, ongoing expenses related to the Implementation Plan will be included in the development of the test year revenue requirement in the Company's next general rate case.

Southwest Gas only has transmission facilities in its southern California jurisdiction. Therefore, only the southern California rate jurisdiction will be impacted by the costs of the proposed Implementation Plan. However, since the Company is not proposing to adjust rates as part of its Implementation Plan, there will be no impact to customer rates until such time as the Commission issues an order and rates are adjusted in the Company's next general rate case.

The estimated annual revenue requirement associated with the Implementation Plan is approximately $1,500,000. The impact to each customer class will ultimately be a function of the approved class-cost-of-service study and the resultant revenue requirement spread. However, on average, the effect on customer rates would be approximately $0.016 per therm. Illustrative monthly bill impacts for each customer class, excluding the amortization of the regulatory asset account, are shown in the following table.

Customer Class	Rate Schedule	Bill Impact
Residential, Primary	GS-10	$0.72
Residential, Secondary	GS-12	$0.56
Core General	GS-35/40	$4.18
Motor Vehicle	GS-50	$136.21
Internal Combustion Engine	GS-60	$26.82
Noncore General	GS-70	$473.58
Multifamily Master Metered	GS-20/25	$27.87

10 IMPLEMENTATION PLAN SUMMARY

Southwest Gas operates approximately 15.4 miles of transmission pipeline in California. Approximately 7.1 miles of transmission pipeline, the Victor Valley Transmission System, is subject to the pressure test requirements of the Order. After careful analysis and comparison of the pipeline pressure testing and pipeline

replacement alternatives, the decision was made to propose the abandonment of the pipeline and install new pipe as part of this Implementation Plan.

Performing pressure tests on the Victor Valley Transmission System would bring the pipeline into compliance with the pressure test requirements of the Order, but poses numerous complications in the process and does not sufficiently address other concerns raised by the Order. Items such as pipe specifications (wall thickness, strength values) and as-built (installation) information for the transmission pipeline are not available. In addition, pipe manufacturing and installation practices are not known with sufficient certainty.

Although the current pipeline is currently operating safely, and has been for 54 years, it does not meet the Order's requirements for pressure testing. The best alternative to meet the requirements of the Order is pipe replacement. A new pipeline that is constructed with modern-day technology, installed with X-ray verification of weld integrity, is properly pressure tested, documented with all pipeline specifications, and installed with modern installation practices will produce a high-degree of confidence in the meeting the requirements of the Order and ensuring the safety of the public.