Company: Southern California Gas Company (U904G)
Proceeding: 2016 General Rate Case
Application: A.14-11-XXX
Exhibit: SCG-08

SOCALGAS

DIRECT TESTIMONY OF MARIA T. MARTINEZ

(PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION)

November 2014

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Southern California Gas Company

A Sempra Energy utility®

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TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
Total Non-Shared	82,057	97,154	15,097
Total O&M	**82,057**	**97,154**	**15,097**

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
Total CAPITAL	**53,042**	**48,637**	**125,184**

- Southern California Gas Company's (SoCalGas or the Company) Transmission Integrity Management Program (TIMP) is founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continual evaluation and reduction of risks to transmission pipelines.

- Through the TIMP, per 49 CFR Part 192, Subpart O, SoCalGas is required to identify threats to transmission pipelines in High Consequence Areas (HCAs), determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure, and report findings to regulators.

- Increased costs in 2016 are attributable to the continued expansion of SoCalGas' ability to in-line inspect transmission pipelines, the use of new technology and the replacement of certain early-vintage distribution pipelines.

- The funding level requested for the TIMP is reasonable and required to meet the requirements of 49 CFR Part 192, Subpart O.

- SoCalGas' Distribution Integrity Management Program (DIMP) is founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continual safety enhancement by proactively identifying and reducing pipeline integrity risks for distribution pipelines.

- Through the DIMP, under 49 CFR Part 192, Subpart P, SoCalGas is required to collect information about its distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators.

- The funding level requested for the DIMP is reasonable and required to meet the requirements of 49 CFR Part 192, Subpart P.

- Major O&M efforts, such as SoCalGas' Sewer Lateral Inspections Program, are required to reduce overall system risk through proactive preventative and remediation activities in DIMP.

- The number of assessment and mitigation activities planned under TIMP and DIMP, which vary from year to year, is the main cost driver for these forecasts. Therefore a zero-based forecast is used.

SOCALGAS DIRECT TESTIMONY OF MARIA T. MARTINEZ
PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION

I. INTRODUCTION

A. Summary of Costs

I sponsor the Test Year (TY) 2016 forecasts for operations and maintenance (O&M) costs for non-shared and shared services and the capital costs for forecast years 2014, 2015 and 2016, associated with the Pipeline Integrity programs for Transmission and Distribution for SoCalGas. Table SCG-MTM-1 summarizes my sponsored costs.

Table MTM-1
Southern California Gas Company
Test Year 2016 Summary of Total Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
Total Non-Shared	82,057	97,154	15,097
Total O&M	**82,057**	**97,154**	**15,097**

TIMP & DIMP			
Shown in Thousands of 2013 Dollars	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
Total CAPITAL	**53,042**	**48,637**	**125,184**

In addition to this testimony, please also refer to my workpapers, Exhibits SCG-08-WP (O&M) and SCG-08-CWP (capital) for additional information on the activities described here.

B. Summary of Activities

The SoCalGas transmission and distribution system operates in 12 different counties and spans from the California-Arizona border to the Pacific Ocean and from the California-Mexico border to Fresno County. SoCalGas is the largest gas distribution operator in the nation, with 98,603 miles of interconnected gas mains and services. SoCalGas is also the second largest transmission operator in HCA miles, with approximately 1,080 miles out of 3,509 miles of pipelines defined as transmission by the United States Department of Transportation (DOT). SoCalGas' unique size and location of operations has a direct and significant bearing on overall costs to comply with federal TIMP and DIMP requirements.

Figure MTM-1
Southern California Gas Company
PHMSA Top 15 Operators by Distribution Miles

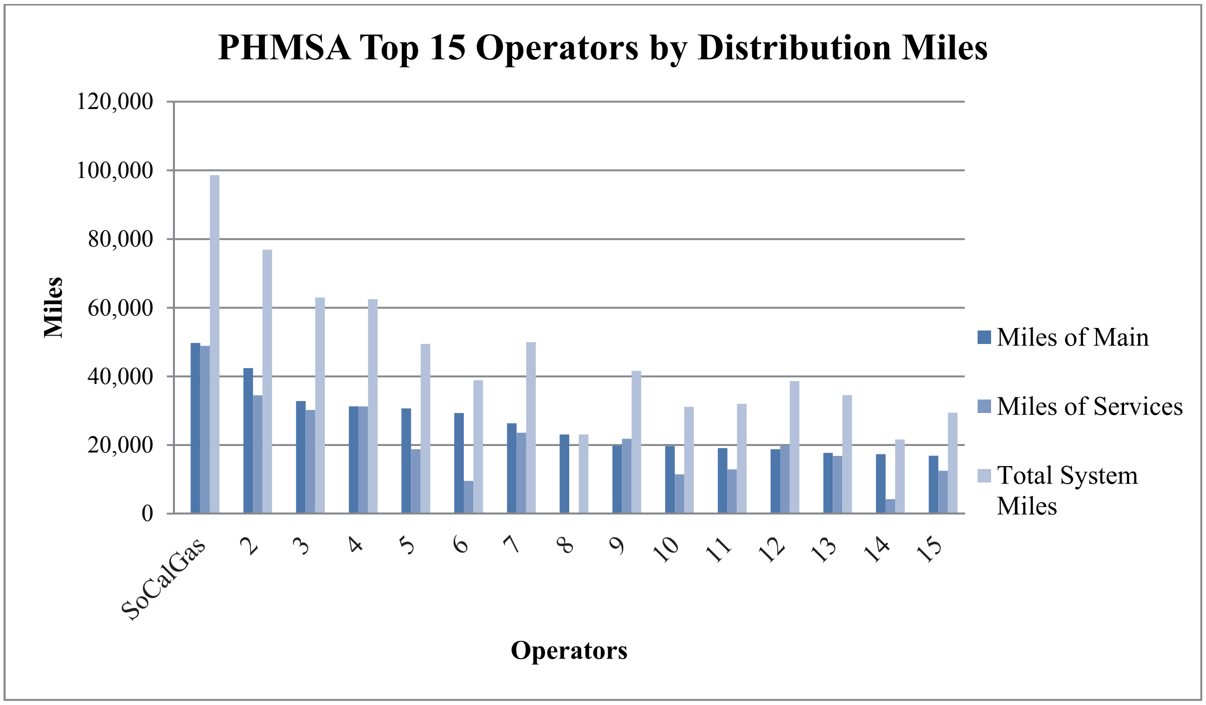
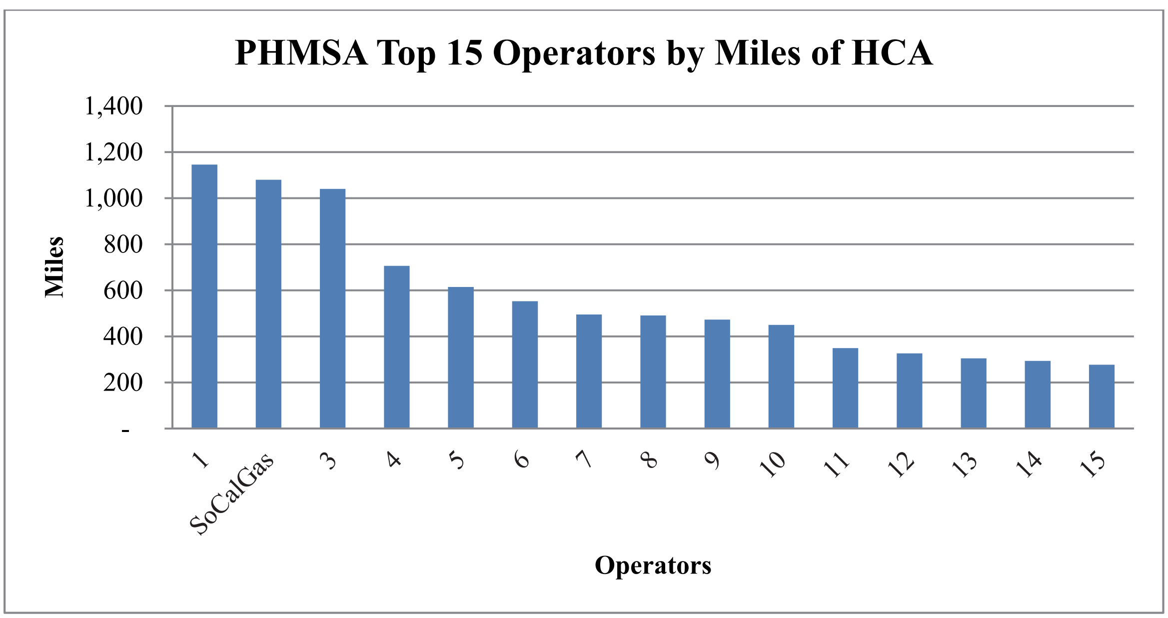


Figure MTM-2
Southern California Gas Company
PHMSA Top 15 Operators by Miles of HCA



Pipeline Integrity for Transmission and Distribution is responsible for implementing and managing the requirements set forth in 49 CFR Part 192, Subpart O– Gas Transmission Pipeline Integrity Management, and Subpart P– Gas Distribution Integrity Management. Under Subpart O, SoCalGas is required to continually identify threats to its pipelines in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats, conduct an appropriate assessment in a prescribed timeline, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure and report findings to regulators. SoCalGas' TIMP is designed to meet these objectives by continually reviewing, assessing and remediating pipelines operating in HCAs and non-HCAs, in order to remain in compliance with federal regulations and provide safe and reliable service to its customers at reasonable rates.[1]

Under 49 CFR Part 192, Subpart P, operators of gas distribution pipelines operators are required to collect information about its distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to its distribution system, evaluate and rank risks to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program, and report findings to regulators. In contrast to the TIMP, DIMP focuses on the entire distribution system, not only pipelines operated in HCAs, since distribution pipelines are largely in developed, more-populated areas to deliver gas to those populations. SoCalGas' DIMP is designed to meet these objectives to remain in compliance with federal regulations and to promote safety and reliability to its customers at reasonable rates.

C. Risk Management Practices in Pipeline Integrity Management Programs

Through its pipeline integrity programs, SoCalGas continually evaluates the transmission and distribution pipeline systems, evaluates and ranks associated risks, and proactively takes action through inspections, replacements and other remediation activities to improve safety and reliability by reducing overall system risk. The risk policy witnesses describe how risks are

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[1] Although TIMP regulations currently only require baseline assessments of transmission pipelines operated in HCAs, in an effort to further enhance the safety and reliability of our system, SoCalGas has expanded its program to include assessments of non-HCA pipelines that are contiguous to or near HCA pipelines on a case-by-case basis.

assessed and factored into cost decisions on an enterprise-wide basis. See Exhibits SCG-02 (Day) and SCG-03 (Schneider/Geier).

Risk evaluation is a critical component of the TIMP and DIMP framework. In this section of my testimony, I describe how risk assessment and management is embedded within the TIMP and DIMP through several processes and how it is the key driver in the scheduling and implementation of assessments and mitigation activities. In TIMP, transmission pipelines are evaluated to identify and address risks in HCAs, as well as non-HCAs. DIMP is focused on evaluating and reducing distribution pipeline integrity risks above and beyond general maintenance requirements. Risk models are used to calculate risk scores, which drive the prioritization of mitigation activities.

1. Risk Assessment

The risks identified through the TIMP and DIMP include risks to public and employee safety, system reliability and physical security. Identified threats that can lead to a pipeline failure have the potential to impact employee and public safety by causing bodily injury, property damage, or disruption of service to customers. The loss of pipeline or facility equipment could impact system reliability by reducing system capacity, inhibiting the ability to efficiently move gas through system and/or diminishing deliverability of gas to customers. This could have a particularly significant impact on customers that provide key health and safety services, such as hospitals and electric generators.

Operating a gas system located in an area that is exposed to earthquakes and severe weather drives us to also consider the effects of natural disasters and the risks they pose. In the TIMP risk evaluation, we look at the potential for loss of pipelines or facilities due to severe weather, earthquakes and land movements.

The analysis of these risks includes the evaluation of the probability of the risks occurring and the potential consequences if a risk is realized. This allows us to comprehensively evaluate our risk exposure in operating our gas pipelines.

2. Risk Mitigation and Alternatives Evaluation

An essential component of an effective risk management program is the development of mitigation plans once risks are identified and analyzed. In TIMP and DIMP, we evaluate potential alternatives for mitigating an identified risk. The condition of the pipeline, operating factors and location are elements considered in evaluating the risk mitigation alternatives.

Within each risk mitigation activity conducted under the TIMP, several alternatives are considered as follows:

Assessments: In evaluating and managing transmission pipeline risks, we consider various assessment options such as External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, In-Line Inspection, Pressure Testing and other assessment methodologies, as further described in later sections of this testimony.

Remediation: Remediation plans are developed based on data collected from the assessment and the options considered for remediating anomalies found in the pipeline.

Additional Preventative and Mitigative Measures: The analysis of data retrieved from the completion of excavations and assessments help determine reassessment cycles and the need for further preventative or mitigative actions on the pipelines. Options considered for further mitigation include the addition of rectifiers, monitoring probes and additional surveys along the pipelines. These preventative measures may eliminate the need for future replacements.

Under the DIMP, causes of distribution pipeline failure fall into different categories and based on that categorization, risk mitigation alternatives are evaluated and considered for each identified cause. Programs to address certain failure mechanisms, such as corrosion on anodeless risers, damage associated with sewer lateral intrusion and vehicular damage associated with above-ground facilities, have been established for risk mitigation. The alternatives considered under these programs include:

Corrosion of Anodeless risers:

- Application of epoxy composite wrap
- Replacement of riser

Vehicular damage to above-ground facilities:

- Barrier construction
- Installation of an Excess Flow Valve
- Relocation of the facility

Pipeline damage from sewer laterals:

- Conflict repair
- Replacement of service

3. Risk Mitigation Activities Selected

Within TIMP, acceptable assessment methods include External Corrosion Direct Assessment, Internal Corrosion Direct Assessment, In-Line Inspection (ILI) and Pressure Testing. An ILI assessment provides an additional level of information that cannot be obtained through other assessment methods. Although the cost of retrofitting a pipeline to allow for ILI may be higher than other alternative assessment methods, the information obtained through an ILI about the condition of the pipeline is extensive and can aid in analyzing time-dependent threats, such as external corrosion and internal corrosion. Therefore, where ILI is one of the methods capable of assessing an identified threat, it is SoCalGas' preferred assessment method. Due to SoCalGas' proactive safety enhancing investments over the years, approximately 82% of transmission pipelines operated by SoCalGas in HCAs, and approximately 61% of the entire transmission system (~2,000 miles as of EOY 2012) can be inspected using ILI. With the additional information obtained from ILIs, a more complete picture of the overall condition of SoCalGas' transmission pipelines can be captured. This allows for an overall risk reduction in both HCA and non-HCA pipe segments.

During the remediation of a pipeline anomaly, SoCalGas considers cost in selecting among various remediation options. For example, where appropriate, SoCalGas will use a welded sleeve over a cylindrical replacement of a pipe segment to remediate an identified threat. The installation of the sleeve provides the same level of safety as a replacement, but at a lower cost. SoCalGas' approach to preventative and mitigative measures seeks to avert the need for pipe replacement in order to achieve the objective or maintaining safe and reliable service at reasonable cost.

4. Integration of Risk Mitigation Actions and Investment Prioritization

The risk assessment that is conducted on transmission and distribution pipelines drives the prioritization of investments to address the most significant risks first. In the TIMP, the employed risk model calculates risk scores for the identified threats using a risk analysis application. The TIMP is designed to prioritize investments based on the risk scores where the most pressing risks are addressed first on a programmatic basis. In the DIMP, the Distribution Risk Evaluation and Monitoring System (DREAMS) tool is used to prioritize risk mitigation of early-vintage pipeline segments, which provides further prioritization for replacement investments based on a leakage root-cause analysis.

5. Investment Dollars Included in the GRC Request to Support Risk Mitigation

The O&M and capital costs summarized in the tables below support TIMP and DIMP activities. The main cost drivers are the assessments for the TIMP and the various Programs and Activities to Assess Risk (PAARs) for the DIMP.

Table MTM-2
Southern California Gas Company
Non-Shared O&M Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
A. TIMP	42,717	55,027	12,310
B. DIMP	39,340	42,127	2,787
Total	**82,057**	**97,154**	**15,097**

Table MTM-3
Southern California Gas Company
Capital Expenditures Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
A. TIMP	37,882	23,317	50,801
B. DIMP	15,160	25,320	74,383
Total	**53,042**	**48,637**	**125,184**

II. NON-SHARED COSTS

Table SCG-MTM-4 summarizes the total non-shared O&M forecasts for the listed cost categories.

Table MTM-4
Southern California Gas Company
Non-Shared O&M Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**2013 Adjusted-Recorded**	**TY2016 Estimated**	**Change**
A. TIMP	42,717	55,027	12,310
B. DIMP	39,340	42,127	2,787
Total	**82,057**	**97,154**	**15,097**

A. Transmission Integrity Management Program Activities

1. Description of Costs and Underlying Activities

To comply with 49 CFR 192, Subpart O—Gas Transmission Pipeline Integrity Management, SoCalGas is required to continually identify threats to transmission pipelines located in HCAs, determine the risk posed by these threats, schedule and track assessments to address threats within prescribed timelines, collect information about the condition of the pipelines, take actions to minimize applicable threats and integrity concerns to reduce the risk of a pipeline failure and report findings to regulators.

The activities prescribed by Subpart O are primarily implemented and managed by the Transmission Integrity Management Program team. The team is composed of engineers, project managers, technical advisors, project specialists and other employees with varying degrees of responsibility. The various activities are categorized into the following seven topics areas of discussion to demonstrate the reasonableness of the labor and non-labor cost associated with the compliance of Subpart O:

- Threat Identification and Risk Assessment;
- Baseline Assessment Plan;
- Assessment;
- Remediation;
- Additional Preventative and Mitigative Measures;

- Geographic Information System (GIS); and
- Auditing and Reporting.

These costs support SoCalGas' goals of operating the system safely and with excellence by continually assessing, mitigating and reducing system risk. The costs will be balanced and recorded in a regulatory balancing account, the Transmission Integrity Management Program Balancing Account (TIMPBA), as described in the Regulatory Accounts testimony of Reginald M. Austria (Ex. SCG-33).

Threat Identification and Risk Assessment: An operator is required to perform threat identification and risk assessment of its transmission pipelines per Subpart O. Threat identification and risk assessment are considered the starting point in SoCalGas' TIMP implementation process. SoCalGas uses a prescriptive approach for threat identification, which includes the nine categories of threats described in ASME B31.8S: External Corrosion; Internal Corrosion; Stress Corrosion Cracking; Manufacturing; Construction; Equipment; Third Party; Incorrect Operations; and Weather Related and Outside Force. All pipelines operated in HCAs are evaluated for each threat category. A risk assessment of the HCA pipelines and identified threats is done through a relative assessment. The relative assessment integrates relevant threats, industry data and Company experience to prioritize HCA pipeline segments for baseline and continual reassessment.

Assessment Plan: Once the pipeline threats are identified, a risk assessment is completed and the HCA pipelines are prioritized, an Assessment Plan is created and maintained to manage the scheduling and due dates for all assessments. In some instances, multiple assessment methods for the same pipeline section may be necessary, depending on the threats that need to be evaluated. The allowable methods prescribed by the DOT Pipeline and Hazardous Material Safety Administration (PHMSA) that may be used for inspecting (assessing) an HCA pipeline are: In-Line Inspection; Pressure Testing, Direct Assessment and Other Technology.[2]

Assessments: The assessment methods primarily employed by SoCalGas are In-Line Inspection, Pressure Testing, External Corrosion Direct Assessment and Internal Corrosion Direct Assessment. The assessment process includes reviewing and gathering historical data, collecting pipelines samples (in some instances), completing the assessment and evaluating the results of the assessment.

[2] 49 CFR 192.921.

In-line Inspection: The in-line inspection method utilizes specialized inspection tools that travel inside the pipeline. SoCalGas plans to complete 21 ILI assessments in 2016, for a total of approximately 600 miles of HCA and non-HCA pipelines. ILI tools are often referred to as "smart pigs." Smart pigs come in a variety of types and sizes with different measurement capabilities that assist in collecting information about the pipeline. This specialized tool requires that the pipeline be configured to accommodate its passage. As this technology did not exist when many pipelines were constructed, the use of this assessment method often requires pipeline segments to be modified or retrofitted to allow passage of the tool. Retrofits include the replacement of valves, removal of certain bends and any other obstruction for passage, as well as the addition of facilities to insert and remove the tool. Once the pipeline is retrofitted to allow passage of the smart pig, a series of pigs are passed through the pipeline to clean out and collect information about the pipeline.

In a conventional ILI assessment, the tool is inserted into the pipeline and pushed by a differential of gas pressure on either side of the tool. In instances where there is insufficient pressure to push the tool through the pipeline, the tool can be tethered and pulled through the pipeline. This process is often referred to as "unconventional ILI." The cost and effort to setup an unconventional ILI is more than a typical ILI assessment, as the pipeline may need to be taken out of service and access points need to be close together to accommodate the length of the tether.

Pressure Test: Pressure testing is a method that uses a hydraulic approach by filling the pipeline, usually with water, at a pressure greater than the maximum allowable operating pressure of the pipeline for fixed period of time. In certain circumstances, the pipeline may be temporarily removed from service post-construction, pressure-tested, and then returned to service. If a leak occurs during the pressure test, the leak is investigated and remediated prior to continuing or completing a pressure test.

External Corrosion Direct Assessment (ECDA): ECDA is a process that proactively seeks to identify external corrosion defects before they grow to a size that can affect the integrity of the inspected pipeline. SoCalGas plans to complete 13 assessments of approximately 32 miles of HCA pipelines using ECDA in 2016. Additional detail supporting this work is provided in my workpapers, Exhibit SCG-08-WP. The ECDA process requires integration of operating data and the completion of above-ground surveys. This information is used to identify and define the severity of coating faults, diminished cathodic protection and areas where corrosion may have occurred or may be occurring. Once these areas are identified, excavation of prioritized sites for pipe surface evaluations to validate or re-rank the identified areas is completed. ECDA is labor-intensive and, depending on the location of the excavations, the cost can be significant.

Internal Corrosion Direct Assessment (ICDA): ICDA is a process that assesses and predicts areas where internal corrosion is likely to occur. The process incorporates operating data, elevation profile, flow modeling and inclination angle analysis. This information is used to identify potential low spots where liquids are most likely to accumulate and where internal corrosion may have occurred or may be occurring. Once these areas are identified, excavation of sites validate if internal corrosion exists at the selected sites. ICDA is labor-intensive and, depending on the results of the detailed examination, a significant increase in the number of excavations may be required.

Remediation: The remediation of a pipeline can occur at different stages depending on the assessment method selected. For an assessment completed using ILI, the remediation occurs after the assessment is complete and the results of the ILI are provided by the vendor. The vendor report provides an overall assessment of the pipeline and possible areas of concerns. The identified areas of concern can vary greatly from assessment to assessment. These areas may include locations where corrosion has occurred or is occurring, as evidenced by indications collected during the inspection. Once these areas are identified, sites are prioritized for pipe surface evaluations to validate or re-rank the identified areas. Remediation through repair or reconditioning of the pipeline coating is completed at the time of excavation. A repair can include a pipe replacement, welded steel sleeve repair or grinding of the defect. ILI anomalies are classified as immediate, scheduled, or monitored, with immediate anomalies being the most severe and requiring immediate action in terms of repair and pressure reductions, as prescribed under 49 CFR 192.933 and ASME B31.8, based on data analysis and evaluation.

An ECDA assessment is complete once the areas identified using the various survey results are excavated and reviewed. In the case of ECDA, the remediation through repair or reconditioning of the pipeline occurs in parallel to the assessment being completed. A repair can include a pipe replacement, welded steel sleeve repair or grinding of the defect.

For a pressure test assessment, the remediation of the pipeline occurs as a result of a failed pressure test and the remediation would need to be completed to continue testing the pipeline. A pressure test cannot be successfully conducted until all remediation work is completed.

Additional Preventative and Mitigative Measures: After the excavations are performed and the assessment is complete, the data is analyzed to determine the need for preventative and mitigative measures and to establish the reassessment interval for the pipeline, up to a maximum of seven years. Preventative and mitigative measures are developed based on the requirements of 49 CFR 192.935(a). When appropriate, the consideration of additional measures for pipeline segments with similar operating conditions will be undertaken for both HCA and non-HCA pipelines.[3] For 2016, preventative and mitigative measures include the addition of rectifiers, monitoring probes, and additional surveys along the pipelines.

Geographic Information System: A GIS is a computer system designed to capture, store, manipulate, analyze, manage and present all types of geographical data. GIS can be thought of as a system that provides spatial data entry, management, retrieval, analysis and visualization functions. SoCalGas currently manages two GIS, one for medium pressure pipelines operating at 60 psig or less, and one for high pressure pipelines operating at greater than 60 psig. In my testimony, the GIS used to manage high pressure pipelines is referred to as the High Pressure Pipeline Database (HPPD) and the GIS used to manage medium pressure pipelines is referred to as the Enterprise GIS or E-GIS. The HPPD is at the core of all TIMP activities and houses and maintains the data collected for transmission pipelines during the pre-assessment process, during the various assessments, and remediation efforts completed as part of TIMP. Maintenance of the HPPD is required to continuously reflect changes in the pipeline system based on new construction, replacements, abandonments or re-conditioning of pipelines for not only TIMP-related projects, but also for all companywide projects in order to analyze the entire transmission pipeline system holistically. Various tool sets (applications) used within the HPPD allow for the analysis and determination of HCAs, relative risk evaluation of the transmission system and the creation of Assessment Plans.

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[3] *See* 49 CFR 192.917(e)(5) *Corrosion.* ("If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in 192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair.")

<u>Auditing and Reporting</u>: The California Public Utilities Commission (CPUC) conducts audits of the TIMP and requests data on a regular basis that must be addressed in a timely manner. On an annual basis, relevant integrity data regarding overall program measures and threat specific measures is gathered and reported per 49 CFR 192.945 and ASME/ANSI B31.8S-2004, section 9.4. The following overall program measures are reported on an annual basis in Form PHMSA F 7100.2-1 Annual Report for Calendar Year (reporting year) Natural and Other Gas Transmission and Gathering Pipeline Systems:

- Number of total system miles existing as of the end of the reporting period;
- Number of total miles inspected during the reporting period;
- Number of total HCA miles covered by the Integrity Management Program , as of the end of the reporting period;
- Number of HCA miles inspected via Integrity Management Program assessments during the reporting period;
- Number of "Immediate" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "One-year" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "Monitored" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of "Other Scheduled" repair conditions completed in HCAs as a result of Integrity Management Program inspections during the reporting period;
- Number of anomalies identified, excavated and repaired (HCA and non-HCA) as a result of Integrity Management Program inspections during the reporting period; and
- Number of leaks (HCA and non-HCA) and failures (HCA), classified by cause, during the reporting period.

2. Forecast Method

The forecast method developed for this cost category is zero-based. Reliance on a five-year average to develop cost forecasts would not be appropriate, because the historic average does not reflect recent upward pressures and expectations created by recent pipeline failure incidents in the industry, such as those that occurred in Sissonville, West Virginia (NTSB No. PAR-14-01), San Bruno, California (NTSB No. PAR-11-01) and Palm City, Florida (NTSB No.

PAB-13-01).[4] Upward pressures on the TIMP include the prudence of expanding inspections beyond HCAs, increasing the ability to assess pipelines using ILI, enhancing data collection practices and improving data traceability.

A zero-based method is most appropriate because the costs directly correlate to the number of assessments conducted each year, which varies from year to year. Results from assessments coupled with the regulatory requirements for reassessment intervals establish the reassessment plan (timeline) for pipelines, which cannot be extended.[5] The forecast methodology is fundamentally rooted on average unit cost, as described in greater detail in my workpapers, Exhibit SCG-08-WP.

3. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as supplemental contracted non-labor for process improvement, process guidance and peak activity level support. The cost drivers are based on the number of assessments (ILI, Direct Assessment or Pressure Test), repairs and mitigation activities required to achieve compliance. Anticipated cost drivers that cannot currently be defined with specificity relate to PHMSA's issuance of a draft process entitled "Integrity Verification Process," on June 28, 2012, which addresses many of the recommendations and mandates outlined by the National Transportation Safety Board and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, signed by President Obama on January 3, 2012. The Integrity Verification Process may impact SoCalGas' TIMP and DIMP activities, depending on the PHMSA's final requirements.

B. Distribution Integrity Management Program Activities

1. Description of Costs and Underlying Activities

These activities are required to comply with 49 CFR Part 192, Subpart P—Gas Distribution Pipeline Integrity Management. PHMSA established DIMP requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for

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4 http://www.ntsb.gov/investigations/reports_pipeline.html.

5 *See* 49 CFR 192.939 (establishing express requirements for determining the reassessment interval for covered pipelines, and stipulating that "the maximum reassessment interval by an allowable reassessment method is seven years.")

distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.[6] This cost will be balanced and recorded in the Post-2011 Distribution Integrity Management Program Balancing Account (DIMPBA), as described in the Regulatory Accounts testimony of Reginald M. Austria (Exhibit SCG-33). These activities are primarily implemented and managed by the DIMP team. The team is composed of engineers, project managers, technical advisors, project specialists and other employees with varying degrees of responsibility. This cost supports the Company's goals of operating the system safely and with excellence by continually assessing, mitigating and reducing overall system risk. The following topics and activities are discussed in additional detail below to demonstrate the reasonableness of the labor and non-labor cost forecasts:

- System Knowledge;
- Threat Identification and Risk Analysis;
- Programs and Activities to Address Risk;
- Geographic Information System; and
- Compliance, Auditing and Reporting.

<u>System Knowledge</u>: System knowledge is developed from reasonably available information and is attained through an understanding of system attributes such as design, materials and construction methods, pipeline condition, past and present operations and maintenance, local environmental factors, and failure data (*e.g.*, leaks). Data collection for SoCalGas' 98,603 miles of distribution main and services is an extensive process that is ongoing and the Company achieved great strides with the transition from numerous legacy systems to E-GIS in 2010.

<u>Threat Identification and Risk Analysis</u>: Threat is defined as a combination of the "Cause" and the "Facility." The major categories of "Causes" are the eight cause categories listed in 49 CFR 192.1015(a)(2): Excavation Damage; Other Outside Force Damage; Corrosion;

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[6] *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements for distribution pipeline systems? ("The Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006 (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. . . . Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.")

Material or Welds; Equipment Failure; Natural Force Damage; Incorrect Operations; and Other. The top level facilities are defined as main, service or above-ground facilities. A risk assessment of the distribution system is done through a relative assessment. The relative assessment integrates several data sets, and considers industry data and Company experience to prioritize programs and activities to address risk.

Programs and Activities to Address Risk: PAARs are implemented through different avenues, depending on the threat being addressed. A holistic view of the entire pipeline distribution system is used when determining a PAAR and its related funding level. In alignment with PHMSA's intent and recognition that a PAAR needs to be operator-specific, SoCalGas develops PAARs that are specific to the SoCalGas system.[7]

Activities can vary from simple changes (such as changing a drop down selection in a data acquisition application for the improvement of the data being collected) to entire programs and funding through rate case filings (such as the sewer lateral inspection program). As noted above, PHMSA's stated purpose for DIMP is to enhance pipeline safety by having operators identify and reduce pipeline integrity risks specifically for distribution pipelines.[8] Since implementing DIMP, SoCalGas has created several PAARs to help achieve that objective and new PAARs will continue to emerge.

The DREAMS PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. With regard to plastic, PHMSA Advisory Bulletin ADB-07-01 states that "the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s." Within the SoCalGas system, there are approximately 20,000 miles of early-vintage pipe in the distribution system. Requiring the replacement of 1,000 miles per year for a 20-year program would be

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7 *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements for distribution pipeline systems? ("…..Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.")

8 *See* PHMSA DIMP FAQ B.1.1: Why did PHMSA mandate integrity management requirements for distribution pipeline systems? ("PHMSA's regulation in part 192 have contributed to producing an admirable safety record. Nevertheless, incidents continue to occur, some of which involve significant consequences, including death and injury. It is not possible to significantly reduce high consequence pipeline incidents without reducing the likelihood of their occurrence on distribution pipelines….")

unrealistic and not adequately consider the performance of the pipe. SoCalGas has therefore implemented a risk evaluation system to accelerate replacements on a targeted basis. The risk evaluation considers the leakage history, cathodic protection (for steel), vintage of the pipe and the location using E-GIS. Each year, SoCalGas targets 55 miles of replacement above and beyond routine replacements in accordance with DIMP regulations. SoCalGas forecasts the capital component under Budget Code 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

The Distribution Riser Inspection Program (DRIP) PAAR addresses the threat of failures of anodeless risers. Anodeless risers are service line components that have shown a propensity to fail before the end of their useful lives. The consequence of this component failing can be significant in that risers are attached to the meter set assembly (MSA), which is usually located next to a residence. There are approximately 2,600,000 anodeless riser units that have the potential to be an integrity threat due to premature failure.

SoCalGas has been involved in research to develop an effective means of mitigating above-ground and ground level corrosion on anodeless risers. This effort has led to the implementation of the epoxy composite wrap, which provides an effective protective barrier for the above ground section of the riser under the environmental conditions that are typical of riser installations, in lieu of replacement of the riser. SoCalGas' rationale for augmenting the ongoing activity is based on PHMSA's requirement that operators go beyond their routine work.[9] SoCalGas forecasts the capital component under Budget Code 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

The Gas Infrastructure Protection Program (GIPP) PAAR addresses potential vehicular damage associated with above-ground distribution facilities. To address vehicular damage to Company facilities, SoCalGas has identified, evaluated and implemented a damage prevention solution that includes a collection of mitigation measures to address this threat. The collection of

[9] PHMSA DIMP FAQ C.3.4: What is the relationship between an operations & maintenance manual and a DIMP plan? ("An O&M manual contains written procedures describing how operators conduct operations and maintenance activities on their system in accordance with Federal and State pipeline safety regulations. The activities address various threats to a pipeline's integrity. A DIMP plan is a written integrity management plan which describes the analysis of the operator's system, provides a relative risk analysis based on threats to the system, and prescribes additional or accelerated actions as needed to address risks identified in the plan…") (emphasis added).

mitigation measures includes: construction of barriers (bollards or block wall); relocation of the facility; or installation of an Excess Flow Valve. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the DIMP.[10] SoCalGas forecasts the capital component under Budget Code 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

The Sewer Lateral Inspection Program (SLIP) PAAR addresses an emerging issue concerning pipeline damage associated with sewer laterals. The integrity threat comes from the use of trenchless technology during installation of pipelines. Trenchless technology provides a means of installing a pipeline without having to excavate a trench along the entire length of the pipeline. Instead of excavating a trench along the entire length of a pipeline, which can be an infeasible and/or much more costly option, the operator can use advanced boring or directional drilling technology to install the pipeline from a single point of entry. An auger, or drill, is affixed to the tip of the pipeline segment and is used to bore or drill the pipeline through existing terrain.

Threats to pipeline integrity can occur during the installation of the pipeline if the auger inadvertently crosses a misplaced sewer line or "lateral" and consequently penetrates, or bores, through all or a portion of the sewer line, creating what is referred to as a "cross bore." The damage to the sewer lateral can either create an immediate blockage or a blockage that slowly and progressively worsens, depending on the encroachment of the gas pipeline. At some point in time, the cross bore can create sufficient blockage to clog drains so that the sewer line needs to be unplugged. A plumber or the property owner then unknowingly uses a cleanout technology, such as a sewer-line auger, to clean out what is seemingly normal sewer debris and blockage. Following this work, the sewer line appears to be unclogged, but in reality the sewer-line auger has pierced the gas line. Depending on how extensive the damage caused by the sewer-line auger, the gas line, which has now been breached, will leak gas into the sewer line and elsewhere. This unwanted gas migration can pose significant risks of bodily injury and damage to property.

[10] *See* PHMSA Gas Distribution Pipeline Integrity Enforcement Guidance: 49 CFR Part 192 – Subpart P, available at: http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_61354CFDB0D1A9033931723B931E3EEF668A0700/filename/DIMP_Enforcement_Guidance(1_29_2014).pdf).

SLIP addresses the concerns PHMSA expressed under the DIMP regulations that require operators to address identified threats of low frequency but potentially high consequence events.[11]

The first step in the SLIP requires a comprehensive review of construction documents for pipelines installed using trenchless technology to identify potential areas where cross bores may have occurred. Through this review of records, SoCalGas identifies areas to be inspected and schedules and prioritizes those inspections. If a cross bore (or bores) is identified, the conflict is either repaired on a spot basis, or if appropriate, the pipe segment may be replaced. In addition to identifying and addressing cross bore conflicts, SoCalGas is developing communication plans to proactively educate plumbing contractors, equipment rental companies and municipalities of this potential issue. SoCalGas forecasts the capital component of this work under Budget Code 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

Geographic Information System: The E-GIS, as mentioned earlier, houses and maintains pipeline information on all distribution pipelines operating at or below 60 psig and is at the core of all DIMP activities. The HPPD also houses information on high pressure distribution pipelines operating above 60 psig. Information gathered during the pre-assessment process and field activities is integrated into the HPPD and E-GIS. The maintenance of these databases through editing and quality control is required to continually reflect changes in the pipeline system based on new construction, replacements and abandonments for not only DIMP-related projects, but also for all Company-wide projects, in order to analyze the entire distribution pipeline system and determine programs and activities needed to address risk. Various tool sets (applications) used within the HPPD and E-GIS allow for analysis and a relative risk evaluation of the distribution system.

Compliance, Auditing and Reporting: On an annual basis, relevant integrity data regarding overall program measures is gathered and reported per 49 CFR 192.1007 and

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[11] PHMSA DIMP FAQ C.4.c.1: What are they key things an operator should be focusing on when developing an effective risk assessment methodology? ("….Operators must consider the risks (likelihood as well as the consequences of a failure) that might result from each threat. A potential incident of relatively low likelihood which produces significant consequences may be a higher risk than an incident with somewhat greater likelihood which may not produce major consequences."

192.1009. The following overall program measures are reported on an annual basis in Form PHMSA F 7100.1-1 Annual Report for Calendar Year (reporting year) Gas Distribution System:

- Excavation Damages;
- Leaks Repaired;
- Number of Hazardous Leaks Repaired; and
- Mechanical Fitting Failures.

2. Forecast Method

The forecast method developed for this cost category is zero-based. SoCalGas implemented DIMP on August 2, 2011, as mandated by the regulations. Since the DIMP has only been officially in place since 2011, reliance on either a five or three-year average for cost forecasting would not be appropriate. The forecast methodology is fundamentally rooted on average unit cost, and described in greater detail in my workpapers, Exhibit SCG-08-WP.

In recent years, incidents in the gas industry, such as the failure that occurred in Saint Paul, Minnesota on February 1, 2010, when a contractor cut a natural gas line while attempting to unclog a sewer pipe, causing an explosion and fire, and the explosion that occurred in Cupertino, California on August 31, 2012, when a plastic pipe (Aldyl-A) failed, damaging a condominium, have applied an upward pressure for Distribution operators to analyze system risk and implement programs and activities to address risk on an accelerated scale not typically experienced by the industry before.

3. Cost Drivers

The cost drivers behind this forecast include both labor and non-labor components. The cost drivers for labor are the Program Management teams required to provide direction, guidance, and oversight to meet compliance and program requirements, as well as the supplemental contracted non-labor for process improvement, process guidance and peak activity level support. The cost drivers with regard to the E-GIS are based on the hours required to maintain the E-GIS, the number of data model changes required to support regulation requirements and the integration of various databases. The cost drivers with regard to the PAARs discussed above are based on time required to gather necessary information, integrate and analyze that information, analyze potential mitigation activities, and implement the selected mitigation approach.

III. CAPITAL

Table SCG-MTM-5 summarizes the total capital forecasts for TIMP and DIMP for 2014, 2015, and 2016.

Table MTM-5
Southern California Gas Company
Capital Expenditures Summary of Costs

TIMP & DIMP			
Shown in Thousands of 2013 Dollars			
Categories of Management	**Estimated 2014**	**Estimated 2015**	**Estimated 2016**
A. TIMP	37,882	23,317	50,801
B. DIMP	15,160	25,320	74,383
Total	**53,042**	**48,637**	**125,184**

A. Transmission Integrity Management Program (Budget Codes 312 and 276)

1. Description

Budget Code 312 captures all TIMP-related capital costs for pipeline defined as transmission under DOT regulations and operated by the Gas Transmission organization within SoCalGas. The forecast for this budget code for 2014, 2015 and 2016 is $34,834, $20,269 and $45,721, respectively.

Budget Code 276 captures all TIMP-related capital cost for pipelines defined as transmission under DOT regulations and operated by the Gas Distribution organization within SoCalGas. The forecast for this budget code for 2014, 2015 and 2016 is $3,048, $3,048 and $5,080, respectively.

As discussed previously, under TIMP regulations, operators of gas transmission pipelines are required to identify the threats to their pipelines, analyze the risks posed by these threats, assess the physical condition of their pipelines, and take actions to address potential threats and integrity concerns before pipeline incidents occur where possible. Through the TIMP, SoCalGas continually evaluates the pipeline system and proactively takes action through inspections, replacements and other remediation activities to improve the safety and reliability of the system. These forecasted capital expenditures support the Company’s core goals of providing safe and reliable service at reasonable cost.

Recent incidents in the gas industry, examples of which are discussed above, has applied an upward pressure on the TIMP to expand inspections beyond HCAs, increase the ability to assess pipelines using in-line inspection and improve data collection and traceability.

As noted previously, SoCalGas has focused on the ability of assessing pipelines using in-line inspection with approximately 82% of transmission pipelines operated by SoCalGas in HCAs, and approximately 61% of the entire transmission system able to accommodate ILI tools as of the end of year 2012. ILI pipeline assessments are performed using an internal electronic device that internally traverses the pipeline to collect information that is used to assess the pipeline. Some pipelines were not designed to accommodate these inspection tools, and therefore a retrofit must be performed along the pipeline route to allow sufficient clearance for the tool during inspection. A typical retrofit may include replacing valves having restrictions with valves that allow inspection devices to traverse internally, insertion of tees with bars, and the change-out of bends and other fittings that may impede the progress of the inspection tool. These retrofit costs are in addition to the installation of the tool launcher and receiver typically installed near the time of inspection. Once the retrofit is completed, the inspection tool is run, followed by excavations to validate the inspection findings and repairs, if needed. Although the cost of retrofitting a pipeline to allow for in-line inspection may be higher than other alternative assessment methods, the information obtained through an in-line inspection about the condition of the pipeline is extensive and can aid in analyzing time dependent threats such as external corrosion and internal corrosions. When possible, multiple pipelines may be combined into a single run and, conversely, a single pipeline may require multiple launcher and receiver points.

When it is more economical than retrofitting a pipeline to conduct an ILI assessment to comply with TIMP regulations, a pipeline may be altered or replaced, if the construction can be implemented within the mandated TIMP assessment schedule.

These forecasted capital expenditures support the Company's core goals of providing safe and reliable service at reasonable cost. Through the TIMP, SoCalGas continually evaluates the transmission pipeline system and proactively takes action through inspections, replacements and other remediation activities to improve the safety and reliability of the system.

Actual TIMP capital costs will be balanced and recorded in the TIMPBA, as described in the Regulatory Accounts testimony of Reginald M. Austria, Exhibit SCG-33. Specific details regarding Budget Codes 312 and 276 may be found in my capital workpapers, Exhibit SCG-08-CWP.

2. Forecast Method

The forecast method developed for this cost category is zero-based. A zero-based method is most appropriate because the costs directly correlate to the number of assessments conducted each year, which varies from year to year. Results from assessments, coupled with the regulatory requirements for reassessment intervals, establish the reassessment plan (timeline) for pipelines, which cannot be extended.[12]

Construction cost estimates are based on experience gained working on projects of similar scope in similar settings. The forecast methodology is fundamentally rooted on average unit cost, as described in greater detail in my workpapers, Exhibit SCG-08-CWP.

3. Cost Drivers

The underlying cost drivers for Budget Codes 312 and 276 relate to the number of assessments (ILI, Direct Assessment and Pressure Test), repairs, and mitigation activities required. Documentation of these cost drivers is included my capital workpapers, Exhibit SCG-08-CWP.

B. Distribution Integrity Management Program (Budget Code 277)

1. Description

Budget Code 277 captures the capital costs related to DIMP that may be incurred as a result of PAAR activities. The forecast for this budget code for 2014, 2015 and 2016 is $15,160, $25,320 and $74,383, respectively.

As discussed previously, operators of gas distribution pipelines are required to identify, evaluate, risk rank and mitigate the threats to their pipelines. This forecast is based on the regulatory requirement to replace identified system components at an accelerated rate. The DREAMS-driven main and service replacements represent activity that is incremental to routine replacement work and required to maintain system integrity, along with compliance with new DIMP regulatory requirements. The GIPP spending focuses on mitigative activities associated with the threat of vehicular damage.

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[12] *See* 49 CFR 192.939 (establishing express requirements for determining the reassessment interval for covered pipelines and stipulating that "the maximum reassessment interval by an allowable reassessment method is seven years.")

These forecasted capital expenditures support the Company's goals of providing safe and reliable service at reasonable cost. Actual DIMP-related capital costs will be balanced and recorded in the Post-2011 DIMPBA, as described in the Regulatory Accounts testimony of Reginald M. Austria, Exhibit SCG-33.

Specific details regarding Budget Code 277 may be found in my capital workpapers, Exhibit SCG-08-CWP.

2. Forecast Method

The forecast method developed for this cost category is zero-based. SoCalGas implemented DIMP on August 2, 2011, as required by applicable regulations. Since the DIMP has only been officially in place since 2011, reliance on either a five or three-year average would not be appropriate. Recent incidents in the gas industry, examples of which are provided above, have applied an upward pressure for distribution operators to analyze the risks to their distribution systems and implement programs and activities to address risk on an accelerated scale not typically experienced by the industry before.

3. Cost Drivers

The cost drivers behind this forecast include both a labor and non-labor component. The cost drivers for the labor component include the Program Management Teams required to provide direction, guidance, oversight to meet compliance and program requirements as well as the supplemental contracting non-labor for process improvement, process guidance and peak activity level support. The underlying cost drivers for the non-labor component relate to the miles of main and number of services targeted for replacement. Documentation of these cost drivers is provided as a supplemental capital workpaper in Exhibit SCG-08-CWP.

IV. CONCLUSION

The funding requested for TIMP and DIMP is reasonable to support the activities outlined and intended to meet the requirements set forth in 49 CFR Part 192, Subpart O–Gas Transmission Pipeline Integrity Management and 49 CFR Part 192, Subpart P–Gas Distribution Integrity Management. SoCalGas' TIMP and DIMP are designed to continually identify and assess risks, remediate conditions that present a potential threat to pipeline integrity, monitor program effectiveness and promote safety and reliability to its customers. This concludes my prepared direct testimony.

V. WITNESS QUALIFICATIONS

My name is Maria T. Martinez. My business address is 555 W. Fifth Street, Los Angeles, California, 90013. I am employed by SoCalGas as the Pipeline Integrity Director for SoCalGas and SDG&E. In this position, I am responsible for providing centralized program support for Pipeline Integrity for both Transmission and Distribution. To accomplish this responsibility, I manage an organization of over 100 employees with varying degrees of technical expertise.

In addition, I possess a broad background in engineering and natural gas pipeline operations with over ten years of experience with SoCalGas. I have held numerous positions with increasing responsibilities within Pipeline Integrity and Gas Distribution Operations. I have been responsible for various areas related to Pipeline Integrity such as Data Collection, Risk and Threat, Assessment Planning and Annual Reporting. I have held my current position as Director of Pipeline Integrity since January 2014.

I hold a Bachelor of Science degree in Mechanical Engineering from California State Polytechnic University, Pomona. I hold a California Professional Engineering License in mechanical engineering from the state of California.

I have not previously testified before the Commission.

APPENDIX A - GLOSSARY OF ACRONYMS

CFR	Code of Federal Regulation
DIMP	Distribution Integrity Management Program
DIMPBA	DIMP Balancing Account
DOT	U.S. Department of Transportation
DREAMS	Distribution Risk Evaluation and Monitoring System
DRIP	Distribution Riser Inspection Program
ECDA	External Corrosion Direct Assessment
GIPP	Gas Infrastructure Protection Program
GIS	Geographic Information System
HCA	High Consequence Area
ICDA	Internal Corrosion Direct Assessment
ILI	In-Line Inspection
PAAR	Program and Activities to Address Risk
PHMSA	Pipeline and Hazardous Material Safety Administration
SLIP	Sewer Lateral Inspection Program
TIMP	Transmission Integrity Management Program
TIMPBA	TIMP Balancing Account