Company: San Diego Gas & Electric Company (U 902 M)
Proceeding: 2019 General Rate Case
Application: A.17-10-___
Exhibit: SDG&E-11

SDG&E

DIRECT TESTIMONY OF MARIA T. MARTINEZ

(PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION)

October 6, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

A Sempra Energy utility®

317249

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SUMMARY

TIMP & DIMP (In 2016 $)			
	2016 Adjusted-Recorded (000s)	**TY 2019 Estimated (000s)**	**Change (000s)**
Total Non-Shared Services	7,744	11,000	3,256
Total O&M	**7,744**	**11,000**	**3,256**

TIMP & DIMP (In 2016 $)			
	Estimated 2017 (000s)	**Estimated 2018 (000s)**	**Estimated 2019 (000s)**
Total CAPITAL	**24,216**	**24,216**	**49,000**

- San Diego Gas & Electric Company's (SDG&E or the Company) Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) are founded upon a commitment to provide safe, clean, and reliable service at reasonable rates through a process of continual safety enhancement by proactively identifying, evaluating, and reducing pipeline integrity risks for transmission and distribution pipelines.
- Through the TIMP, per 49 Code of Federal Regulations (C.F.R.) § 192,[1] Subpart O, SDG&E is federally mandated 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.
  - The funding level requested for the TIMP is to meet the requirements of 49 C.F.R. § 192, Subpart O.
- Through the DIMP, under 49 C.F.R. § 192, Subpart P, SDG&E is federally mandated 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

[1] Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards, 49 C.F.R. § 192 *et seq*.

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 to meet the requirements of 49 C.F.R. § 192, Subpart P.

- The numbers of assessment and mitigation activities planned under TIMP and DIMP vary from year to year. For TIMP, this is primarily based on the timing and intervals of prior assessments. Therefore, a zero-based forecast is used to more accurately reflect activities anticipated to occur during the General Rate Case (GRC) cycle.

SDG&E DIRECT TESTIMONY OF MARIA T. MARTINEZ (PIPELINE INTEGRITY FOR TRANSMISSION AND DISTRIBUTION)

I. INTRODUCTION

A. Summary of Pipeline Integrity Costs and Activities

I sponsor the Test Year (TY) 2019 forecasts for operations and maintenance (O&M) costs for non-shared services and the capital costs for forecast years 2017, 2018, and 2019 associated with the Pipeline Integrity programs for Transmission and Distribution for SDG&E. Table MTM-1 summarizes my sponsored costs.

Table MTM-1
San Diego Gas & Electric Company
Test Year 2019 Summary of Total Costs

TIMP & DIMP (In 2016 $)			
	2016 Adjusted-Recorded (000s)	**TY 2019 Estimated (000s)**	**Change (000s)**
Total Non-Shared Services	7,744	11,000	3,256
Total Shared Services (Incurred)	0	0	0
Total O&M	**7,744**	**11,000**	**3,256**

TIMP & DIMP (In 2016 $)				
	2016 Adjusted-Recorded (000s)	**Estimated 2017 (000s)**	**Estimated 2018 (000s)**	**Estimated 2019 (000s)**
Total CAPITAL	**26,002**	**24,216**	**24,216**	**49,000**

SDG&E is founded upon a commitment to provide safe, clean, and reliable service at reasonable rates through a process of continual safety enhancement by proactively identifying, evaluating, and reducing pipeline integrity risks for transmission and distribution pipelines. This commitment requires SDG&E to execute on the TIMP and DIMP to continually reduce the overall system risk through prescriptive assessments on transmission pipelines as required by Subpart O; and identify and implement, projects, programs, or other activities above and beyond general maintenance as required by Subpart P. Specifically, the activities discussed herein:

- maintain and enhance safety;
- are consistent with local, state, and federal regulatory and legislative requirements;
- maintain overall system integrity and reliability; and

- support SDG&E's commitment to mitigate risks associated with hazards to customer/public safety, infrastructure integrity, and system reliability.

This testimony discusses non-shared and shared expenses in support of functions for the TIMP and DIMP. In addition to this testimony, please also refer to my workpapers, Exhibits SDG&E-11-WP (O&M) and SDG&E-11-CWP (Capital) for additional information on the activities described here.

The Pipeline Integrity for Transmission and Distribution organization is responsible for implementing and managing the requirements set forth in 49 C.F.R. § 192, Subpart O – Gas Transmission Pipeline Integrity Management, and Subpart P – Gas Distribution Integrity Management. Under Subpart O, SDG&E 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.

SDG&E is also the twenty-ninth largest transmission operator in HCA miles, with approximately 188 miles out of 225 miles of pipelines defined as transmission by the United States Department of Transportation (DOT). SDG&E's unique size and location of operations has a direct and significant bearing on overall costs to comply with federal TIMP requirements.

SDG&E's TIMP is designed to meet these objectives by continually reviewing, assessing, and remediating pipelines operating in HCAs and non-HCAs. These activities are required to remain in compliance with federal regulations, and provide safe, clean, and reliable service to its customers at reasonable rates. 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 the system, SDG&E expanded its program to include assessments of non-HCA pipelines that are contiguous to or near HCA pipelines on a case-by-case basis.

Under 49 C.F.R. § 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. SDG&E is the forty-fifth largest gas distribution operator in the nation, with 14,088 miles of interconnected gas mains and services. SDG&E's 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.

B. Summary of Safety- and Risk Assessment Mitigation Phase (RAMP)-Related Costs

My testimony includes costs to mitigate High-Pressure Pipeline and Medium-Pressure Pipeline risks primarily associated with public and employee safety, system reliability, regulatory and legislative compliance, and pipeline system integrity. Specific risks, mitigating measures, and associated costs are further discussed in Section II of my testimony. All of the costs supported in my testimony are driven by activities described in SDG&E and Southern California Gas Company's (SoCalGas) November 30, 2016 Risk Assessment Mitigation Phase (RAMP) Report. The RAMP Report presented an assessment of the key safety risks of SDG&E and proposed plans for mitigating those risks. As discussed in the Risk Management testimony chapters of Diana Day and Jamie York (Exhibit SCG-02/SDG&E-02, Chapters 1 and 3, respectively), the costs of risk mitigation projects and programs were translated from that RAMP Report into the individual witness areas.

In the course of preparing my GRC forecasts, I continued to evaluate the scope, schedule, resource requirements, and synergies of RAMP-related projects and programs. Therefore, the final representation of RAMP costs may differ from the ranges shown in the original RAMP Report. Table MTM-2 provides a summary of the RAMP-related costs supported by my testimony by RAMP risk:

Table MTM-2
San Diego Gas & Electric Company
Summary of RAMP-Related Costs (O&M and Capital)

TIMP & DIMP (In 2016 $)			
RAMP Risk Chapter	**2016 Embedded Base Costs (000s)**	**TY 2019 Estimated Incremental (000s)**	**Total (000s)**
SDG&E-10 Catastrophic Damage Involving High-Pressure Gas Pipeline Failure	4,717	283	5,000
SDG&E-16 Catastrophic Damage Involving Medium-Pressure Pipeline Failure	3,027	2,973	6,000
Total O&M	**7,744**	**3,256**	**11,000**

TIMP & DIMP (In 2016 $)			
RAMP Risk Chapter	**2017 Estimated RAMP Total (000s)**	**2018 Estimated RAMP Total (000s)**	**2019 Estimated RAMP Total (000s)**
SDG&E-10 Catastrophic Damage Involving High-Pressure Gas Pipeline Failure	3,997	3,997	4,000
SDG&E-16 Catastrophic Damage Involving Medium-Pressure Pipeline Failure	20,219	20,219	45,000
Total Capital	**24,216**	**24,216**	**49,000**

C. Organization of Testimony

My testimony is organized as follows:

- Introduction
  - Summary of Pipeline Integrity Costs and Activities
  - Summary of Safety- and Risk Assessment Mitigation Phase (RAMP)-Related Costs
- Risk Assessment Mitigation Phase and Safety Culture
  - RAMP
  - Safety Culture
- Non-Shared Costs

- o Transmission Integrity Management Program Activities
  - o Distribution Integrity Management Program Activities
- Capital Costs
  - o Transmission Integrity Management Program (Budget Code (BC) 3468)
  - o Distribution Integrity Management Program (BC 9546)
- Conclusion

My testimony also references the testimony of several other witnesses, either in support of their testimony or as referential support for mine. Those witnesses are Gina Orozco-Mejia (Exhibit SDG&E-04, Gas Distribution), Ms. Day and Ms. York (Ex. SCG-02/SDG&E-02, Chapter 1: Risk Management and Policy and Chapter 3: RAMP to GRC Integration, respectively), Omar Rivera (Exhibit SDG&E-05, Gas System Integrity), Norma Jasso (Exhibit SDG&E-41, Regulatory Accounts), and Ms. York (Exhibit SCG-45/SDG&E-44, Compliance).

II. RISK ASSESSMENT MITIGATION PHASE AND SAFETY CULTURE

A. RAMP

The RAMP chapters represented and supported as part of this testimony are the chapters for "Catastrophic Damage Involving High-Pressure Failure" and "Catastrophic Damage Involving Medium-Pressure Pipeline Failure."

As illustrated by Tables MTM-3, MTM-4, and MTM-5, part of our requested funds is linked to mitigating top safety risks that have been identified in SDG&E's RAMP Report.

Table MTM-3
San Diego Gas & Electric Company
RAMP Risks Summary

RAMP Risk	Description
SDGE-10 Catastrophic Damage Involving High-Pressure Pipeline Failure	This risk relates to the potential public safety and property impacts that may result from the failure of high-pressure pipelines (greater than 60 pounds per square inch (psi)).
SDGE-16 Catastrophic Damage Involving Medium-Pressure Pipeline Failure	This risk relates to the public safety and property impacts that can result from failure of medium-pressure pipelines (60 psi and less).

Table MTM-4
San Diego Gas & Electric Company
RAMP O&M Summary Breakdown of Costs

TIMP & DIMP O&M (In 2016 $)			
SDG&E-10 Catastrophic Damage Involving High-Pressure Gas Pipeline Failure	**2016 Embedded Base Costs (000s)**	**TY 2019 Estimated Incremental (000s)**	**Total (000s)**
1TD000.000, TIMP	4,717	283	5,000
Total	**4,717**	**283**	**5,000**
SDG&E-16 Catastrophic Damage Involving Medium-Pressure Pipeline Failure	**2016 Embedded Base Costs (000s)**	**TY 2019 Estimated Incremental (000s)**	**Total (000s)**
1TD000.001, DIMP	3,027	2,973	6,000
Total	**3,027**	**2,973**	**6,000**

Table MTM-5
San Diego Gas & Electric Company
RAMP Capital Summary Breakdown of Costs

TIMP & DIMP Capital (In 2016 $)			
SDG&E-10 Catastrophic Damage Involving High-Pressure Gas Pipeline Failure	**2017 Estimated RAMP Total (000s)**	**2018 Estimated RAMP Total (000s)**	**2019 Estimated RAMP Total (000s)**
034680.001, RAMP - Base BC 3468 is SDG&E TIMP	3,997	3,997	4,000
Total	**3,997**	**3,997**	**4,000**
SDG&E-16 Catastrophic Damage Involving Medium-Pressure Pipeline Failure	**2017 Estimated RAMP Total (000s)**	**2018 Estimated RAMP Total (000s)**	**2019 Estimated RAMP Total (000s)**
095460.001, RAMP - Base BC 9546 is SDG&E DIMP DREAMS	20,219	20,219	22,346
095460.002, RAMP - Incremental BC 9546 is SDG&E DIMP DREAMS	0	0	22,654
Total	**20,219**	**20,219**	**45,000**

The TIMP and DIMP are relatively new federal code requirements that go above and beyond routine maintenance activities by monitoring and remediating risk on the pipeline system with the goal of reducing overall risk. As further discussed in later sections, the TIMP manages this risk reduction through the execution of assessments and remediation of transmission pipelines in populated areas on a reoccurring set schedule. The DIMP manages this risk reduction by implementing targeted activities, programs, or projects that provide an extra layer of monitoring, assessment, or proactive remediation. In the California Public Utilities Commission's (CPUC or Commission) Safety and Enforcement Division (SED) report on our RAMP, SED recommended that Southern California Gas Company (SoCalGas)/SDG&E consider applying dynamic segmentation analysis on their pipeline system. In the RAMP, the companies used the enterprise risk management process to evaluate risks across the companies, which is a broader perspective that does not dive into the details of how specific mitigation activities are prioritized. See Ex. SCG-02/SDG&E-02/Day, Chapter 1. At a programmatic-level, dynamic segmentation is already being applied as a part of our early vintage replacement program analysis where we assess individual pipeline segments and relatively rank them by evaluating pipeline segment performance. This type of analysis helps us look at specific mitigation activities and how to prioritize our work.

B. Safety Culture

SDG&E's longstanding commitment to safety focuses on three primary areas: (1) employee/contractor safety, (2) customer/public safety, and (3) the safety of our gas delivery systems. This safety focus is embedded in what we do and is the foundation for who we are – from initial employee training, to the installation, operation and maintenance of our utility infrastructure, and to our commitment to provide safe, clean, and reliable service to our customers.

SDG&E regularly assesses its safety culture and encourages two-way communication between employees and management as a means of identifying and managing safety risks. In addition to the reporting of pipeline and occupational safety incidents, there are multiple methods for employees to report close calls/near misses. At SDG&E, safety is a core value so we provide all employees with the training necessary to safely perform their job responsibilities SDG&E takes an integrated approach to pipeline integrity and safety, beginning with the design and construction of facilities and followed by continual evaluation and improvement of operation and maintenance activities, public communication and awareness, emergency response, safety programs and practices, the implementation of new technologies, defined procurement processes that facilitate materials traceability, and a workplace that encourages continual open and informal discussion of safety-related issues.

The DIMP and TIMP programs at SDG&E are compliance-driven efforts designed to create a safe and reliable natural gas supply and delivery system by maintaining the gas system integrity. The programs also create and reinforce a safety culture within SDG&E and the communities we serve. The processes that we have developed to fulfill the compliance requirements of TIMP and DIMP integrate several characteristics that are consistent with a safety culture. For example, the TIMP and DIMP include a management of change (MOC) process that promotes communication, transparency, training, and sustainability by understanding the impact of the change, the changes required to the program, and communication/training requirements to reinforce the change and validate understanding.

The TIMP and DIMP programs are founded upon the commitment to provide safe, clean, and reliable service at reasonable rates through a process of continual evaluation and reduction of risks to transmission pipelines and a process of continual safety enhancements by proactively identifying and reducing pipeline integrity risks for distribution pipelines. Both DIMP and TIMP programs, together, have over 190 allocated resources within an organization where roles and responsibilities are the successful fulfillment of our commitment to safety and reliability compliance. To date, TIMP has inspected, remediated, and validated the safety of 144 miles of transmission pipelines using in-line inspection (ILI) technology in both HCA and Non-HCAs. Within TIMP, when an area requires remediation or immediate attention based on assessment results, prompt action is taken for the safety of public and personnel working on the pipeline, which may include pressure reduction or removing pipelines from service until a repair can be completed.

Additional elements of a safety culture illustrated by the DIMP and TIMP programs are their use of data, continual improvement, and risk identification to drive the budget and spending decisions of SDG&E. The process starts with identifying the specific assets and the risks associated with those assets. Data and data analysis are used to evaluate those risks and develop mitigation strategies to address the impact and/or frequency of the risk. For example, as part of DIMP, the threat of excavation damage has been identified as a risk that requires additional mitigation strategies to address the frequency of the risk. To address this threat, the Damage Prevention advisors have been created, which is discussed in further detail later in my testimony. In many cases, SDG&E is evaluating existing mitigation programs and efforts for opportunities for improvement. Finally, the mitigation strategies result in infrastructure-related budget requests as part of the corporate budget decision process.

At the core of the TIMP and DIMP is safety, as these programs provide an opportunity to continually assess risk on the system and proactively identify areas of improvements. The programs are central to safety metrics, which track the compliance and accountability of each activity, project, or program implemented by TIMP and DIMP. These safety metrics are developed by management and understood by the employees supporting TIMP and DIMP. These safety metrics are further discussed herein to demonstrate progress and performance, and as part of the GRC Accountability Report included in Ms. York's Compliance testimony (Ex. SCG-45/SDG&E-44).[2]

III. NON-SHARED COSTS

Table MTM-6 summarizes the total non-shared O&M forecasts for the listed cost categories.

Table MTM-6
San Diego Gas & Electric Company
Non-Shared O&M Summary of Costs

TIMP & DIMP (In 2016 $)			
Categories of Management	**2016 Adjusted-Recorded (000s)**	**TY 2019 Estimated (000s)**	**Change (000s)**
A. TIMP	4,717	5,000	283
B. DIMP	3,027	6,000	2,973
Total Non-Shared Services	**7,744**	**11,000**	**3,256**

A. Transmission Integrity Management Program Activities

1. Description of Costs and Underlying Activities

To comply with 49 C.F.R. § 192, Subpart O – Gas Transmission Pipeline Integrity Management, SDG&E 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

[2] The GRC Accountability Report as described in D.16-06-054 at 331-32 (OP 11).

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 TIMP 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 topic areas of discussion to demonstrate the reasonableness of the labor and non-labor costs associated with Subpart O compliance:

- 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 SDG&E's goals of operating the system safely and with excellence by continually assessing, mitigating, and reducing system risk.

The costs of implementing TIMP will be balanced and recorded in a regulatory balancing account, the Transmission Integrity Management Program Balancing Account (TIMPBA), as described by Ms. Jasso (Ex. SDG&E-41). Should the balance in the TIMPBA exceed the forecast due to unanticipated activities, such as remediation of a pipeline in an environmentally sensitive or difficult to access area, expansion of assessments beyond HCAs to further enhance public safety, augmentation of existing pipelines to enable the use of ILI technology to assess pipeline integrity, or enhancement of data management practices, recovery of account balances above authorized levels could be requested through an advice letter, as described by Ms. Jasso (Ex. SDG&E-41).

<u>Threat Identification and Risk Assessment</u>: 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 SDG&E's TIMP implementation process. SDG&E uses a prescriptive approach for threat identification, which includes the nine categories of threats described in American Society of Mechanical Engineers (ASME) Standard 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. For example, if external and internal corrosion are both identified as a threat to a pipeline, this may require concurrent completion of External Corrosion Direct Assessment (ECDA) and Internal Corrosion Direct Assessment (ICDA). 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: ILI, Pressure Testing, Direct Assessment, and Other Technology.[3]

Assessments: The assessment methods primarily employed by SDG&E are ILI, Pressure Testing, External Corrosion Direct Assessment, and Internal Corrosion Direct Assessment. The assessment process includes reviewing and gathering historical data, collecting pipeline samples (in some instances), completing the assessment, and evaluating the results of the assessment. Selection of an assessment method may vary, but these common assessment methods are generally described below:

- ILI: The ILI method utilizes specialized inspection tools that travel inside the pipeline. SDG&E plans to complete 1 ILI assessment in 2019. 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

[3] *See* 49 C.F.R. § 192.921(a). As reflected in the workpapers supporting my testimony, SDG&E currently anticipates utilizing ILI and ECDA assessment methods during the GRC cycle. The method used to assess pipeline integrity could change based on a change in threat identification.

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. Since the ILI tools are generally run for the length of the pipeline, the benefit is that the assessment provides information for both HCA and non-HCA transmission pipeline segments. Using ILI, SDG&E has been able to inspect approximately 25 extra miles of non-HCA transmission pipelines since the inception of the program.

- 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 (MAOP) of the pipeline for a 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.
- 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. SDG&E plans to complete 9 assessments using ECDA in 2019. Additional detail supporting this work is provided in my workpapers, Ex. SDG&E-11-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 (CP), 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.
- 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 concern. 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 C.F.R. § 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 C.F.R. § 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.[4] For 2019, preventative and mitigative measures include the addition of rectifiers, monitoring probes, and additional surveys along the pipelines.

GIS: 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. SDG&E currently manages two GIS, one for medium-pressure pipelines operating at 60 psi or less, and one for high-pressure pipelines operating at greater than 60 psi. 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 (eGIS). 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 company-wide projects to holistically analyze the entire transmission pipeline system. 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.

Auditing and Reporting: On an annual basis, relevant integrity data regarding overall program measures and threat-specific measures is gathered and reported per 49 C.F.R. § 192.945 and ASME / American National Standards Institute Standard B31.8S-2004, Section 9.4 to PHMSA with copies provided to the CPUC. The following examples are overall program measures that 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:

[4] *See, e.g.,* 49 C.F.R. § 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."

- 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; and
- Number of HCA miles inspected via Integrity Management Program assessments during the reporting period.

2. Forecast Method

The forecast method developed for this cost category is zero based. Reliance on a three- or five-year average to develop cost forecasts would not be appropriate, because the historic average does not reflect anticipated changes in scope from year to year. The transmission pipeline assessments in HCAs are completed at a maximum of every seven years so each year the number and type of assessments that need to be completed changes. A three-year (or four-year) GRC cycle only represents a small window of the seven-year TIMP cycle and would not appropriately forecast anticipated cost. A zero-based method is most appropriate because the costs directly correlate to the number of assessments conducted each 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, Ex. SDG&E-11-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 to achieve compliance. Anticipated cost drivers that cannot currently be defined with specificity relate to PHMSA's issuance of the Notice of

[5] *See* 49 C.F.R. § 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.").

Proposed Rulemaking (NPRM) for Natural Gas Transmission Pipelines,[6] which include, but are not limited to, the Integrity Verification Process (IVP), the introduction of a "Moderate Consequence Area" (MCAs), and enhancements to records requirements.

B. Distribution Integrity Management Program Activities

1. Description of Costs and Underlying Activities

These activities are to comply with 49 C.F.R. § 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 distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006.[7] This cost will be balanced and recorded in the Post-2011 Distribution Integrity Management Program Balancing Account (DIMPBA), as described by Ms. Jasso (Ex. SDG&E-41). Should the balance in the DIMPBA exceed the forecast due to unanticipated activities, based on continual threat and risk analysis, recovery of account balances above authorized levels could be requested through an advice letter, as described by Ms. Jasso (Ex. SDG&E-41).

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;

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[6] *See* NPRM, 81 Fed. Reg. 20721 (Apr. 8, 2016), *available at* https://www.regulations.gov/document?D=PHMSA-2011-0023-0118. *See also* https://phmsa.dot.gov/pipeline/phmsa-proposes-new-safety-regulations-for-natural-gas-transmission-pipelines.

[7] *See* PHMSA Gas Distribution Integrity Management Program: FAQs, Section B: General DIMP Questions, No. 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. . . .").

- Threat Identification and Risk Analysis;
- Programs /Projects and Activities to Address Risk;
- GIS; and
- Compliance, Auditing, and Reporting.

System Knowledge: 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 SDG&E's 14,088 miles of distribution main and services is an extensive process that is continually being improved upon through targeted research and changes in data capture as needed.

Threat Identification and Risk Analysis: 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 C.F.R. § 192.1015(a)(2): Excavation Damage; Other Outside Force Damage; Corrosion; 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/Projects and Activities to Address Risk (PAAR): These PAAR programs are intended to address risk above and beyond current regulatory requirements (federal and state), as intended by PHMSA. 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, SDG&E develops PAARs that are specific to the SDG&E system.[8]

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 gas inspection protection project). As noted

[8] *Id*.

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.[9] Since implementing DIMP, SDG&E has created several PAARs to help achieve that objective and new PAARs will continue to emerge.

The Gas Infrastructure Protection Project (GIPP) PAAR addresses potential third-party vehicular damage associated with above-ground distribution facilities. Since the start of the program in 2011, approximately 31,500 inspections have been completed and over 2,170 sites remediated. The GIPP PAAR forecast for remediation is 15 non-standard sites a year. To address this threat of vehicular damage to Company facilities, SDG&E has identified, evaluated, and implemented a damage prevention solution that includes a collection of mitigation measures, including: 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] SDG&E forecasts the capital component under Budget Code 3468 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

The Damage Prevention Advisor Program (DPAR) will focus its efforts on reducing the number of third-party damages to SDG&E's distribution system. DPAR will consist of a staff of employees that will be working in the field to actively communicate the importance of the One-Call notification (811 Dig Alert) and safe excavation practices. In addition, the team will assist in damage investigations, and collect information regarding the work practices of excavators.

The Vintage Integrity Plastic Plan (VIPP) is a proposed tiered approach based on a foundation of safety and system risk reduction that addresses the threat of 1,600 miles of early vintage plastic, primarily including Aldyl-A. In 2007, PHMSA issued an Advisory Bulletin ADB-07-01, which states that "the number and similarity of plastic pipe accident and non-

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[9] *Id*. ("PHMSA's regulations 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.").

[10] *See* PHMSA "Gas Distribution Pipeline Integrity Enforcement Guidance: 49 C.F.R. § 192 – Subpart P," at 22, *available at* https://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/DIMP_Enforcement_Guidance(1_29_2014).pdf.

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." The brittle-like cracking characteristic could cause a leak on an early vintage plastic pipeline to grow and release additional natural gas than would normally be released, increasing the risk of natural gas gathering and igniting. Given the potential for a higher release of gas, the first tier of VIPP would focus on increasing the monitoring leak survey for 1,200 miles of early vintage plastic that is currently not on a yearly cycle; there are 400 miles already on a yearly cycle, for example, because they are within a business district that requires a yearly leak survey. This increased survey would provide for the opportunity to detect a leak on early vintage plastic prior to an incident occurring. The details of the yearly survey cost starting in 2019 are further discussed by Ms. Orozco-Mejia (Ex. SDG&E-04). The second tier is targeting the replacement of early vintage plastic manufactured pre-1973. This vintage of plastic exhibits the brittle-like cracking characteristics discussed, but also exhibits a Low Ductile Inner Wall (LDIW) issue that further exacerbates the brittle-like cracking issues since it expedites crack initiation when external loads are applied. This issue in the manufacturing practice has been the main focus of earlier notices issued by the manufacturer DuPont and PHMSA. Therefore, the second tier of VIPP will focus on the wholesale replacement of pre-1973 plastic pipe with a priority given to poor performing segments by utilizing a relative risk model and dynamic segmentation. The final tier of VIPP will leverage the same relative risk model and dynamic segmentation to continue to focus on the replacement of poor performing early vintage plastic for all pre-1986 plastic pipe. Starting in 2019, SDG&E plans to target 27 miles of mains and associated services for replacement above and beyond routine replacements in accordance with DIMP regulations with a 25- to 30-year horizon for wholesale replacement of early vintage plastic. With a 30-year horizon, SDG&E anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through VIPP through indicators such as leak repair and incident rates related to early vintage plastic. SDG&E forecasts the capital component under Budget Code 277 – Distribution Integrity Management Program. This capital expenditure is explained in the capital portion of my testimony.

GIS: The eGIS, as mentioned earlier, houses and maintains pipeline information on all distribution pipelines operating at or below 60 psi and is at the core of all DIMP activities. The HPPD also houses information on high-pressure distribution pipelines operating above 60 psi. Information gathered during the pre-assessment process and field activities is integrated into the HPPD and eGIS. The maintenance of these databases through editing and quality control must 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 eGIS allow for analysis and a relative risk evaluation of the distribution system. These activities are baseline requirements to adequately maintain the HPPD and eGIS. In contrast, the funding requested by Mr. Rivera (Ex. SDG&E-05) in relation to the HPPD and eGIS is intended to go above and beyond baseline requirements and look for opportunities to integrate these GIS systems with other databases, such as Work Management and Document Management to increase the efficiency of managing pipeline-related records and data analytics.

Reporting: On an annual basis, relevant integrity data regarding overall program measures is gathered and reported per 49 C.F.R. §§ 192.1007 and 192.1009. The periodic evaluation of performance metrics provides the opportunity to determine whether actions taken to address threats are effective, or whether different actions are needed. An overall decrease in the number and consequences of pipeline incidents is the goal, but it will take many years of accumulating data to determine with confidence that there is a declining trend. 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. SDG&E implemented DIMP on August 2, 2011, as mandated by the regulations. The forecast methodology is fundamentally rooted on average unit cost, and described in greater detail in my workpapers, Ex. SDG&E-11-WP.

3. Cost Drivers

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 validated and reinforced the need for Distribution operators to continue investing in plans such as VIPP previously discussed to address risk on an accelerated scale not typically experienced by the industry before. The VIPP is the main cost driver for the increased cost during this 2019 GRC since the program will continue to ramp-up to address the threat of non-state-of-the-art plastic (Aldyl-A) in a more aggressive manner.

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 for the eGIS are based on the hours required to maintain the eGIS, the number of data model changes required to support regulation requirements, and the integration of various databases. The cost drivers for 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.

IV. CAPITAL COSTS

Table MTM-7 summarizes the total capital forecasts for TIMP and DIMP for 2017, 2018, and 2019.

Table MTM-7
San Diego Gas & Electric Company
Capital Expenditures Summary of Costs

TIMP & DIMP (In 2016 $)			
Categories of Management	**Estimated 2017**	**Estimated 2018**	**Estimated 2019**
A. TIMP	3,997	3,997	4,000
B. DIMP	20,219	20,219	45,000

Total	**24,216**	**24,216**	**49,000**

A. Transmission Integrity Management Program (Budget Code 3468)

1. Description of Costs and Underlying Activities

Budget Code 3468 captures all TIMP-related capital costs for pipelines defined as transmission under DOT regulations and operated by the Gas Transmission organization within SDG&E. The forecast for this budget code for 2017, 2018, and 2019 is $3,997, $3,997, and $4,000, respectively.

As previously discussed, 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, where possible, to address potential threats and integrity concerns before pipeline incidents occur. Through the TIMP, SDG&E 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, clean, and reliable service at reasonable rates.

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

As previously noted, SDG&E has focused on the ability of assessing pipelines using ILI with approximately 64% of the entire transmission system able to accommodate ILI tools as of the end of year 2016. 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 with less-restrictive 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 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 and internal corrosion. 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, clean, and reliable service at reasonable rates. Through the TIMP, SDG&E 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 by Ms. Jasso (Ex. SDG&E-41). Specific details regarding Budget Code 3468 may be found in my capital workpapers, Ex. SDG&E-11-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.[11]

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 capital workpapers, Ex. SDG&E-11-CWP.

3. Cost Drivers

The underlying cost drivers for Budget Codes 3468 relate to the number of required assessments (ILI, Direct Assessment, and Pressure Test), repairs, and mitigation activities. Documentation of these cost drivers is included my capital workpapers, Ex. SDG&E-11-CWP.

[11] *See* 49 C.F.R. § 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.").

B. Distribution Integrity Management Program (Budget Code 9546)

1. Description of Costs and Underlying Activities

Budget Code 9546 captures the capital costs related to DIMP that may be incurred as a result of PAAR activities. The forecast for this budget code for 2017, 2018, and 2019 is $20,219, $20,219, and $45,000, respectively.

As previously discussed, 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 Distribution Risk Evaluation and Monitoring System (DREAMS)[12]-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 mitigation activities associated with the threat of vehicular damage.

These forecasted capital expenditures support the Company's goals of providing safe, clean, and reliable service at reasonable rates. Actual DIMP-related capital costs will be balanced and recorded in the Post-2011 DIMPBA, as described by Ms. Jasso (Ex. SDG&E-41).

Specific details regarding Budget Code 9546 may be found in my capital workpapers, Ex. SDG&E-11-CWP.

2. Forecast Method

The forecast method developed for this cost category is zero based since the primary driver for cost are activities, projects, or programs that may change or be completed from year to year.

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, and 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 mains and number of services targeted for replacement. Documentation of these

[12] In the DIMP, the 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.

cost drivers is provided as a supplemental capital workpaper, Ex. SDG&E-11-CWP. 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. The VIPP is the main cost driver for the increased cost during this 2019 GRC since the program will continue to ramp-up to address the threat of non-state-of-the-art plastic (Aldyl-A) in a more aggressive manner.

V. 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 C.F.R. § 192, Subpart O – Gas Transmission Pipeline Integrity Management and 49 C.F.R. § 192, Subpart P – Gas Distribution Integrity Management. SDG&E's 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.

VI. 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 fifteen 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 previously testified before the Commission in the previous GRC A.14-11-003 (D.16-06-054).

LIST OF ACRONYMS

ACRONYM	DEFINITION
ADB	Advisory Bulletin
AES	AutoSol Enterprise System
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BC	Budget Code
C.F.R.	Code of Federal Regulations
CP	Cathodic Protection
CPUC	California Public Utilities Commission
DIMP	Distribution Integrity Management Program
DIMPBA	Distribution Integrity Management Program Balancing Account
DOT	Department of Transportation
DPAR	Damage Prevention Advisor Program
DREAMS	Distribution Risk Evaluation and Monitoring System
ECDA	External Corrosion Direct Assessment
eGIS	Enterprise Geographic Information System
GIPP	Gas Infrastructure Protection Project
GIS	Geographic Information System
GRC	General Rate Case
HCA	High Consequence Area
HPPD	High-Pressure Pipeline Database
ICDA	Internal Corrosion Direct Assessment
ILI	In-line Inspection
IVP	Integrity Verification Process
LDIW	Low Ductile Inner Wall
MAOP	Maximum Allowable Operating Pressure
MCA	Moderate Consequence Area
MOC	Management of Change
NPRM	Notice of Proposed Rulemaking
O&M	Operations and Maintenance
PAAR	Programs/Projects and Activities to Address Risk
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Pipeline Integrity, Protection, Enforcement and Safety Act of 2006
psi	pounds per square inch
RAMP	Risk Assessment Mitigation Phase
SDG&E	San Diego Gas & Electric Company
SED	Safety and Enforcement Division
SoCalGas	Southern California Gas Company
TIMP	Transmission Integrity Management Program
TIMPBA	Transmission Integrity Management Program Balancing Account
TY	Test Year
VIPP	Vintage Integrity Plastic Plan

APPENDIX A – Glossary of Applications

Application	Description
SAP-PM	System for managing Maintenance and Inspection work in Gas Distribution
ClickScheduling	System for Scheduling and Dispatching Maintenance and Inspection work
ClickMobile	System for electronic delivery of work orders to the field personnel and capturing Maintenance and Inspection results
NBMS	New Business Management System to initiate new business projects
CMS	Construction Management System to plan and reconcile construction work
Data Mart	Tools for storage, analysis and reporting of Maintenance and Inspection results
ARCOS	Automated Resources Call Out System to assemble and track repair utility crews for emergency and after hour work by automating the calling process and complex scheduling, union and business rules.
Maximo	System for managing Maintenance and Inspection work in Gas Transmission and Gas Storage
WOT	Work Order Tracking – Business Process/Work Management system for managing activities in Gas Distribution Technical Services.
MyProjects	Business Process/Work Management system for managing construction projects in Gas Engineering, Gas Transmission, PCM, Pipeline Safety Enhancement Plan (PSEP), and Gas Storage
PDMS	Pipeline Document Management System
DRIP Forms	Electronic forms used for collecting Inspection data related to Distribution Riser Inspection Project (DRIP)
GIPP Forms	Electronic forms used for collecting Inspection data related to GIPP
SLIP	Electronic forms used for collecting Inspection data related to Sewer Lateral Inspections Project (SLIP)
DIMP/TIMP Risk Mgmt	Risk calculating application & Risk Score Reporting tool for SCG and SDG&E

GOPS	System for creating weather conditions reports
Lab Analysis	Data collection and approval workflow management system for lab analysis related to determining leaks root causes
IBM Cognos	Reporting system for Maximo, Eccentex, and Visiflow applications
Interlocs	Mobile system for Maximo work order delivery and Inspection Data Collection
OSI/PI	Data historian and Engineering/Operations analysis system for Gas Storage Supervisory Control and Data Acquisition (SCADA) Data
Autosol/AES	Electronic Pressure Monitoring and Alarm System for SCG and SDG&E
DDB	Electronic repository for storage and retrieval of Engineering Design Drawings
DDS	Electronic Design Data Sheet – Engineering Test Pressure Calculator