BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) for Review of its Safety Model Assessment Proceeding Pursuant to Decision 14-12-025.	Application No. 15-05-___ (Filed May 1, 2015)

PREPARED DIRECT TESTIMONY OF
MARI SHIRONISHI
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

May 1, 2015

Southern California Gas Company
A Sempra Energy utility®

#296296

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF
MARI SHIRONISHI
ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

I. INTRODUCTION

The purpose of this testimony is to present the Transmission Integrity Management Program ("TIMP") and its associated models. TIMP is a prescriptive process for identifying threats, prioritizing and completing assessments, and acting upon assessment results. It is a continual process that is used to both validate the integrity of transmission pipelines as well as prevent pipeline failures, thus increasing pipeline safety and reducing reliability risks. As described in the testimony of Jorge DaSilva, Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") apply a six-step risk management process; Risk Identification, Risk Analysis, Risk Evaluation and Prioritization, Mitigation Plan, Allocation of Funds, and Monitoring and Review. As described further in this testimony, SoCalGas and SDG&E's TIMP process includes elements of this six step process to address transmission pipeline risks.

II. BACKGROUND

A. Pipeline Safety Improvement Act of 2002

On December 17, 2002 the Pipeline Safety Improvement Act of 2002 was signed into law. Subsequently, 49 Code of Federal Regulations ("C.F.R.") Part 192 Subpart O – *Gas Transmission Pipeline Integrity Managemen*t was published and made effective on January 14, 2004. Under this rule, operators of Department of Transportation ("DOT") defined natural gas transmission pipelines are required to institute a program to identify the threats to their pipelines in High Consequence Areas ("HCAs"), analyze the risk posed by these threats, collect information about the physical condition of their pipelines and take actions to address the applicable threats and integrity concerns to increase safety and preclude pipeline failures. The nine threat categories that must be considered are: External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force.

The code requirements of Subpart O are prescriptive in nature and provide the details of what an operator must include in its integrity management program and steps that must be followed to implement the code requirements. In addition to its specific requirements, the federal code also "incorporates by reference" the requirements of industry standards such as the American Society for Mechanical Engineers ("ASME") /American National Standards Institute ("ANSI") B31.8S – *Supplement to B31.3 on Managing System Integrity of Gas Pipelines* and National Association of Corrosion Engineers ("NACE") Standard Practice SP0502 – *Pipeline External Corrosion Direct Assessment Methodology*. These industry standards provide in depth methodologies and calculations for more specific and technical requirements addressed in the code.

The integrated SoCalGas and SDG&E transmission pipeline system is managed under a single comprehensive TIMP intended to meet the requirements of Subpart O. Subpart O applies to all Transmission Pipelines, with focus on pipelines located in HCAs.[1] Currently, about 35% of transmission pipeline for both utilities are located in HCAs as defined in Subpart O.

B. Transmission Integrity Management Program – Risk Management Process Overview

Within TIMP, the nine threat categories (External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force) are evaluated and a score of the Likelihood of Failure ("LOF") is calculated for each transmission pipeline located within a HCA. Pipeline operational parameters and the area near the pipeline is also evaluated and a score of the Consequence of Failure ("COF") is calculated for each transmission pipeline located within an HCA. The LOF multiplied by the COF produces the pipelines Relative Risk Score ("RRS"). The RRS of each pipeline were used to prioritize the sequencing of baseline assessments.

Further information is collected about the physical condition of transmission pipelines through integrity assessments. Action is taken to address applicable threats and integrity concerns to increase the safety and preclude pipeline failures. The priority of the integrity

[1] Means an area established by one of the methods described in paragraphs (1) or (2) as follows:
(1) An area defined as –
a. A Class 3 location under § 192.5; or
b. A Class 4 location under § 192.5; or
c. Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
d. Any area in a Class 1 or Class 2 location where the potential impact radius contains an identified site.
(2) The area within a potential impact circle containing –
a. 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
b. An identified site.

assessment is driven by the risk assessment of each of the threats and is managed through an Assessment Plan. The Assessment Plan manages the scheduling and selection of appropriate assessment methods based on threats identified on HCA segments. Subpart O allows for assessment of HCA segments with In-Line Inspection ("ILI"),[2] Pressure Test, [3] Direct Assessment ("DA") and Other Technology. SoCalGas and SDG&E primarily utilize ILI, Pressure Test, External Corrosion Direct Assessment ("ECDA")[4] and Internal Corrosion Direct Assessment ("ICDA") as assessment methods. The integrity assessment process includes reviewing historical data, completing the assessment and evaluating the results of the assessment. Using assessment data, a remediation plan is established to address any integrity concerns found during assessments. Examples of remediation activities can include pipe segment replacement, installation of repair sleeve, removal of defects and reconditioning of coating. After the completion of an Assessment Plan, data is analyzed further to determine if additional preventative measures are needed. Also during this time, the re-assessment interval is determined based on the conditions found on the transmission pipeline, not to exceed a maximum of seven years.

III. TIMP RISK ASSESSMENT

A. Determining the Relative Risk Score

Each operator must complete a Risk Assessment that addresses all nine threat categories in order to prioritize assessments of HCA pipeline segments. In order to evaluate and analyze each threat category, the code, through ASME B31.8BS, allows for four types of Risk Assessment approaches: (1) Subject Matter Experts ("SMEs"), (2) Relative Assessment Models, (3) Scenario-Based Models and (4) Probabilistic Models. SoCalGas and SDG&E currently utilize a Relative Assessment Model with embedded elements of SME input. The code also recognizes that each operator across the country is unique and therefore requires the details of a risk model be developed by the operator.

[2] A pipeline inspection technique that uses devices known in the industry as "smart pigs." These devices are self-contained tools or vehicle that moves through the interior of the pipeline for inspecting, dimensioning, cleaning, or drying and provide indications of metal loss, deformation and other defects.
[3] A measure of the strength of a piece of pipe in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.
[4] A four-step process that combines pre-assessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

All of these Risk Assessment approaches determine risk using two primary factors explained in the ASME B31.8S: LOF and COF. The first risk factor, LOF, represents the probability that a pipeline failure or adverse effect may occur, and the second risk factor, COF represents the impact that a pipeline failure could have on the public, employees, property, and the environment. SoCalGas and SDG&E calculate these risk factors and RRS by dynamic pipeline segment. A dynamic pipeline segment has characteristics (diameter, coating, material, etc.) that make it unique from adjacent pipe.

The LOF analysis for each dynamic segment is a function of the nine threat categories. The evaluation of each threat is dependent on predetermined threshold values established by SME input and guidance provided in AMSE B31.8S that accounts for the susceptibility of the threat being present. SoCalGas and SDG&E have assigned LOF weighting by incorporating company incident data and national DOT incident statistics by threat type and assessment results. When the threat specific risk score exceeds the predetermined threshold value, the susceptibility of the threat is considered present. The threshold values have been conservatively set to include threats for additional activity unless there are definitive data that shows the threat to be stable or not present.

The COF for each dynamic segment addresses all nine consequence factors listed in ASME/ANSI B31.8S-2004 Section 3.3.

- Population Density
- Proximity of the Population to the Pipeline
- Proximity of Populations with Limited or Impaired Mobility
- Property Damage
- Environmental Damage
- Effects of Unignited Gas Release
- Security of Gas Supply
- Public Convenience and Necessity
- Potential for Secondary Failures

These nine categories listed above are incorporated into the following three (3) factors:

- Potential Impact Radius (“PIR”)
- Class Location
- The hoop stress of the pipeline segment within the PIR at Maximum Allowable Operating Pressure (“MAOP”) as a percent of the Specified Minimum Yield Strength (“% SMYS”)

RRS of a dynamic segment is given by the product of the LOF and the COF, as given by the following formula: RRS = (LOF * COF) / 10,000, with a maximum RSS being 100. The pipeline's HCA segment with the highest RRS sets the RRS for the entire pipeline to allow for the assessment of the entire pipeline at the same time.

B. Inputs of Risk Model

The pipeline segment information used in our Risk Assessment is obtained from the High Pressure Pipeline Database (“HPPD”) which houses relevant physical and operational data for high pressure pipelines and allows for dynamic segmentation. The following pipe attribute data is used: material, diameter, wall thickness, coating, year of installation, long seam type and girth weld type.

Operational and land data are also utilized in the Risk Assessment process. This data includes assessment data, cathodic protection (“CP”) criteria, internal corrosion presence, proximity to compressor stations and compressor station discharge temperatures, % SMYS, equipment failure, incorrect operation events, farm land use, foreign line crossing locations, liquefaction areas, slope presence, landslide and Alquist Priolo fault line data.

The knowledge of these pipe attributes and operational data within the pipeline system allow for evaluation of individual pipeline segments by assigning different risk factors, which provides more complete understanding of the pipeline system. In addition, land data can provide areas that are susceptible to third party damage and any earth or soil movements near the pipelines.

C. Ranking Risk for the Baseline Assessment Plan

TIMP is a process for evaluating and reducing pipeline risks. Pipeline operators must conduct assessments of pipe segments within HCA areas where a gas pipeline failure would have a significant impact on public safety. HCAs are further described as places where population densities, in the vicinity of transmission pipeline facilities, are high. Also included in the description are areas of generally recognized public gathering places (parks, beaches, campsites, etc.) and places of limited mobility such as hospitals and correctional facilities.

Further, the regulations are applicable to an operator's DOT-defined transmission piping system. These pipes are typically larger in diameter, operate at higher pressures, and designed to move large volumes of gas from one point to another before being distributed for end-use consumption. Based on these operating characteristics, their operating pressures are typically at levels above 20% of a pipe segments SMYS. The higher the % SMYS rating for the highest operating pressure, the greater the risk of a rupture failure. SoCalGas and SDG&E assign a higher risk factor to pipelines that operate at elevated % SMYS levels. Through the threat and risk evaluation process described in this testimony, the safety and reliability threats are associated to specific pipe segments and subsequent risk factors are applied in order to relatively rank and prioritize each segment for further activity.

The initial ranking and prioritization of these covered segments formulated what is known as the Baseline Assessment Plan ("BAP"). The BAP was a risk-ranked listing of all covered segments, in descending order, and utilized to conduct the first cycle of assessments. 50% of the covered segments beginning within the highest risk segments were required to be assessed by December 17, 2007 and a complete assessment of all covered segments by December 17, 2012 per regulation. As mentioned before, reassessments are also required at frequencies not to exceed seven years.

SoCalGas and SDG&E have been also proactively assessing non-HCA transmission pipeline segments. Approximately 57% of ILI and approximately 20% of ECDA assessed mileages are non-HCA transmission pipeline segments. Also, the consideration of additional preventative and mitigative measures for pipeline segments with similar operating conditions have been undertaken for both HCA and non-HCA pipelines.

D. Prescriptive Re-Assessment Intervals

The Relative Assessment Model method provided the ability to prioritize each integrity assessment at the origination of the TIMP. However, since the fundamental inputs of the Relative Assessment do not change significantly from year to year, the primary driver for the subsequent integrity assessments is the requirements set by Subpart O, which requires a minimum reassessment interval of seven years. Both ASME/ANSI B31.8S and NACE SP0502 contain detailed calculations for establishing reassessment intervals using the results of the previous assessment(s) as well as knowledge gained from integrated data generated through the integrity processes performed throughout the system that could be used to reduce the seven year interval further. SoCalGas and SDG&E use the assessment data to identify locations on the pipe for excavation and direct examination of the pipe to verify assessment results. These "in the ditch" measurements are used to calibrate the assessment data, and, in some instances, result in additional excavations of the pipeline for remediation. Pipeline anomalies found during excavations are addressed to prevent the need to return to the location for remediation in the future. Using a conservative approach to validate assessment data typically results in the calculated remaining life far exceeding the seven year assessment interval.

IV. TIMP RISK MITIGATION PLANNING

An essential element of an effective risk management program is the development of mitigation plans once risks are identified and analyzed. Risk mitigation options are considered in various stages of the TIMP process, including selections of assessment methods, development of remediation and mitigation plans, and any additional preventative measures.

CFR 49 Part 192 Subpart O allows TIMP to utilize a number of methods to assess HCA segments. They are Direct Assessment (External Corrosion Direct Assessment /Internal Corrosion Direct Assessment/Stress Corrosion Cracking Direct Assessment), ILI, Pressure Testing and other technologies to assess covered segments. While most pipelines were installed prior to the requirements of making all new pipelines able to be in-line inspected, SoCalGas and SDG&E have retrofitted pipelines to enable an ILI assessment. ILI is the preferred assessment method since more extensive data on condition of the pipeline can be obtained and can aid in a more thorough and comprehensive pipeline specific risk analysis. Approximately 79% of transmission pipelines in HCAs and 64% of the entire transmission system can be currently inspected using ILI.

Remediation and mitigation plans are developed based on data collected from assessments and analyzing anomalies found in the pipeline. A defect assessment is performed to calculate the remaining life of anomalies found, and repair/replacement decisions of those anomalies are made, whether they are in an HCA or not. The analysis of data retrieved from the completion of direct examinations and assessments help determine reassessment intervals and the need for further preventative actions on the pipelines. Options considered for further mitigation include the addition of pipeline recoating, rectifiers, monitoring probes and additional surveys along the pipelines.

V. ILLUSTRATIVE EXAMPLE

Below is an illustrative example of how the TIMP risk management process can work in analyzing the threats to pipelines and preventing pipeline failures. This example is intentionally simplistic for the purposes of this discussion to illustrate in a simple manner how the TIMP addresses transmission pipeline risks and how single variables in the pipeline can impact the risk assessment. This example is not intended to present a comprehensive example of the type of analysis that occurs in TIMP, which typically involves pipelines with unique variables to consider.

Figure 1 below illustrates a pipeline A traversing through a highly populated area and continuing into a rural area. The attributes of the pipeline (diameter, install date, wall thickness, operating pressure, MAOP, etc.) are identical throughout its entire length. The only variable in this example is the population density surrounding the pipeline. The pipeline A is going through Class 3 to Class 1 location, which creates two dynamic segments within the same pipeline.

Under the TIMP, SoCalGas and SDG&E would first calculate the LOF score for all nine threat categories for each of the dynamic pipeline segments within the HCA. In this case an internal corrosion threat was identified. Next SoCalGas and SDG&E would calculate the COF score for dynamic segments. As Table 1 illustrates, change in just the class location from a Class 1 to Class 3 location results in an impact on the COF, nearly doubling the score from 320 to 590, signifying an increased risk relative to the Class 3 pipeline segment. When an internal corrosion threat is present on a pipeline, SoCalGas and SDG&E's preferred method of assessment is ILI. Therefore, in this example, SoCalGas and SGD&E would use ILI to further assess the pipeline and develop appropriate remediation activities. Although both of the pipeline segments in Table 1 below have different RRS scores, the highest dynamic segment RRS within the HCA segment sets the RRS for the HCA, therefore the baseline assessment of this pipeline will be scheduled based on the highest RRS of the pipeline. In this example, the high RRS score would be 45 (out of a maximum of 100) as identified for Pipeline A.

FIGURE 1

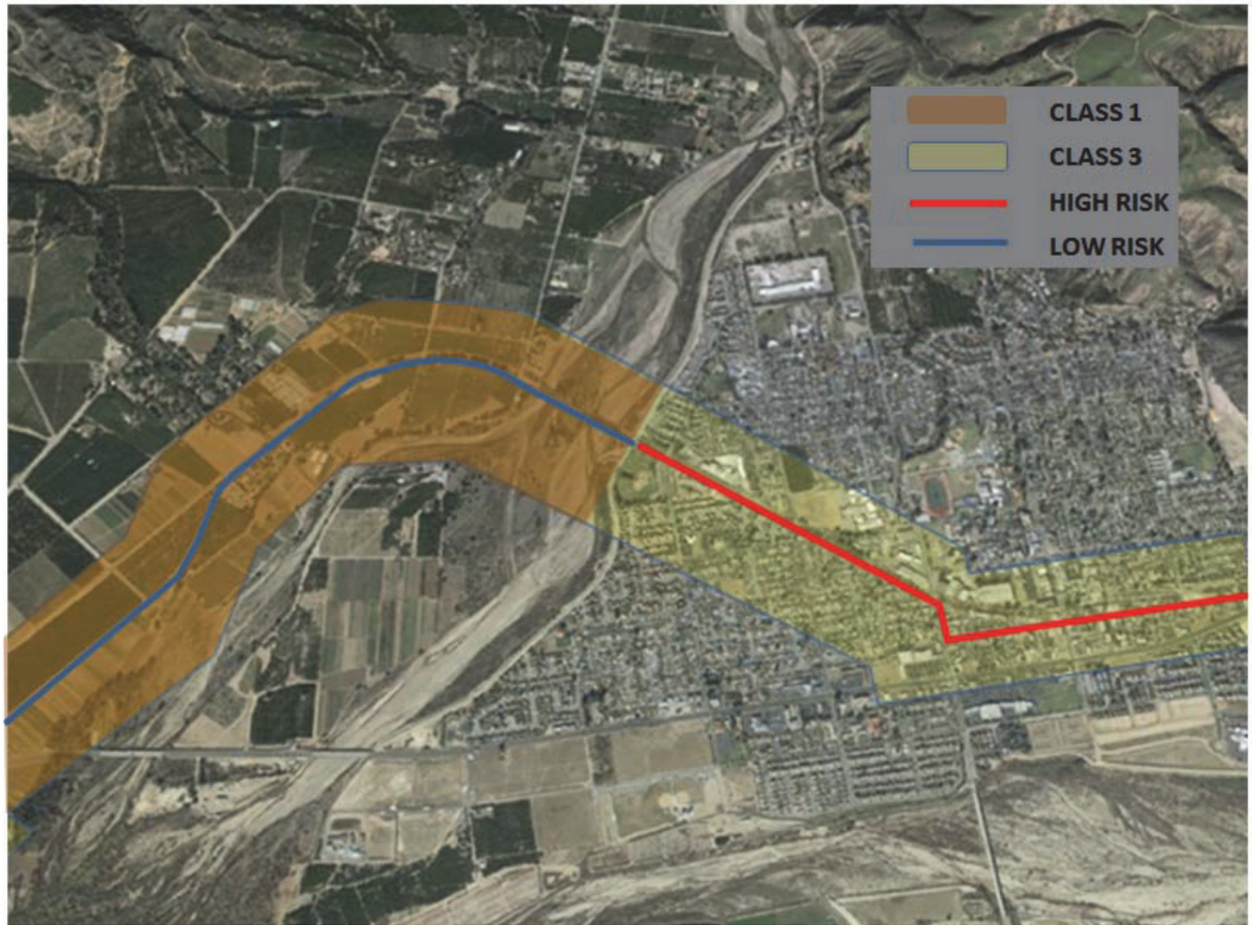

TABLE 1[5]

				COF Inputs				LOF Input	
Pipeline Name	Max Risk Score	Dynamic Segment Risk Score	Dynamic Segment Length (mile)	COF Score	PIR	Class Location	% SMYS	LOF Score	IC LOF Score
A	27	27	0.1	590	230	Class 3	43	460	22
A	27	15	0.3	320	230	Class 1	43	460	22

VI. MONITOR AND REVIEW FOR CONTINUAL IMPROVEMENTS

SoCalGas and SDG&E have greatly expanded their use of integrity management techniques over the last decade since the implementation of TIMP, starting with a framework that built upon well-established safety and reliability practices for the design, construction,

[5] Note that the numbers in Table 1 are illustrative.

#296296

operation, and maintenance of its system to TIMP as it exists today. Looking forward, as the TIMP continues to mature over the years and additional data becomes available, such as new assessment data, new consequence information, or more comprehensive operational data, the Risk Assessment process will also evolve. As an example, assessment data from ILI or ECDA provide an opportunity to perform reliability based risk assessment; reassessment of ILI can provide corrosion growth rate or strain analysis; direct examination data can provide accurate pipe data and soil information; and ECDA can provide better CP data and depth of cover. These data sets are critical elements to move towards probabilistic risk analysis. Similarly, SoCalGas and SDG&E are using additional tools and techniques on subsequent assessments to provide more data that, once integrated, will better support probabilistic risk analysis. In addition, SoCalGas and SDG&E have expanded the assessment scope to cover areas outside of HCAs to better understand the larger picture of the surrounding pipeline conditions. This is not an overnight effort, but a long term process that includes the collection and integration of the right type of data to further enhance the safe and reliable operation of the gas transmission system. SoCalGas and SDG&E will continue to improve the Risk Assessment process as the TIMP continues to evolve and will strive to use Risk Assessment results as a means to quantify decisions to prioritize and mitigate risks.

This concludes my prepared direct testimony

VII. WITNESS QUALIFICATIONS

My name is Mari Shironishi. I am employed by SoCalGas. My business address is 505 West Fifth Street, Los Angeles, California 90013. Since 2014, I have been the Team Lead of Pipeline Integrity Risk & Threat Team where I oversee the process of identifying threats and analyzing risk of transmission pipelines under TIMP. I started my career with SoCalGas in 2009. During this time I have held various positions of increasing responsibility within the Pipeline Integrity group, including Integrity Engineer on the ECDA team and Team Lead of Assessment Planning.

Before joining SoCalGas, I worked for Pacific Gas & Electric Company as a Gas Distribution Engineer and ILI Engineer. I hold a Bachelor of Science degree in Mechanical Engineering from the University of California, Davis.

I have not testified previously before the Commission.