Attachment B

Declaration of Travis Sera

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

In The Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project.	Application 15-09-013 (September 30, 2015)

DECLARATION OF TRAVIS SERA IN SUPPORT OF THE RESPONSE OF APPLICANTS SAN DIEGO GAS & ELECTRIC COMPANY (U902G) AND SOUTHERN CALIFORNIA GAS COMPANY (U904G) IN OPPOSITION TO MOTION THE OF THE OFFICE OF RATEPAYER ADVOCATES TO DISMISS APPLICANTS' APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT LINE 3602

I, Travis Sera, declare:

1. I am presently employed as a Pipeline Integrity Manager for Southern California Gas Company.

2. Based on my knowledge and experience, I make this declaration in support of the Response of Applicants San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) in Opposition to the Motion of the Office of Ratepayer Advocates To Dismiss Applicants' Application For A Certificate Of Public Convenience And Necessity To Construct Line 3602.

3. On March 21, 2016, my prepared direct testimony ("Testimony") was served and incorporated by reference to the Amended Application of the above captioned proceeding, a true and correct copy of which is attached hereto as Exhibit 1. Based on my knowledge and experience, the contents of my Testimony are true and accurate and incorporated herein by reference.

I declare under penalty of perjury, under the laws of the State of California, that to the best of my knowledge, the foregoing is true and correct. Executed on July 1, 2016, at Los Angeles, California.

/s/ Travis Sera
Travis Sera

<u>EXHIBIT 1</u>

PREPARED DIRECT TESTIMONY OF TRAVIS SERA ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY

Application No: A.15-09-013
Exhibit No.:
Witness: T. Sera

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	Application 15-09-013 (Filed September 30, 2015)

PREPARED DIRECT TESTIMONY OF

TRAVIS SERA

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

March 21, 2016

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I. PURPOSE AND OVERVIEW

The purpose of my prepared direct testimony on behalf of San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the Utilities) is to explain why replacing the existing transmission function of Line 1600 and converting the pipeline to distribution service, rather than pressure testing, would provide a greater margin of safety and overall risk reduction.[1]

Line 1600 was first placed in service in 1949, more than a decade before the Commission first adopted pressure testing and recordkeeping regulations for transmission pipelines, and the Utilities do not have documentation to demonstrate that Line 1600 was pressure tested when initially placed in service. Therefore, Line 1600 was "grandfathered" under federal pressure testing regulations adopted in 1970.[2] As such, Line 1600 is required to be pressure tested, replaced or removed from transmission service to comply with the California Natural Gas Pipeline Safety Act of 2011 and Decision (D.) 11-06-017.

The Utilities' PSEP is designed to achieve the goal of orderly and cost-effectively replacing or testing all natural gas transmission pipelines that do not have pressure test documentation. Alternatively, where operationally feasible, the Utilities can reduce the operating pressure of a transmission line to a distribution level pressure to increase the margin of safety on the line and remove it from the scope of Public Utilities Code Section 958 and D.11-06-017. For Line 1600, the Utilities propose to lower the operating pressure to distribution

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[1] As described in the Amended Application, the Utilities retained PricewaterhouseCoopers (PwC) to perform a cost-effectiveness analysis of the Proposed Project and the alternatives identified in the Ruling. *See* Amended Application, Volume III – Cost-Effectiveness Analysis. The Cost-Effectiveness Analysis and underlying methodology were performed by PwC with input and data from the Utilities. In addition to responding to the Ruling's requirements to address the increased safety benefits and supporting analysis, I have provided data input to the Cost-Effectiveness Analysis as well as other data inputs for the portions of the analysis that pertain to my testimony below.

[2] *See* D.11-06-017, at 5 n.3.

service. As explained further in my testimony below, lowering the operating pressure on Line 1600 will permanently and significantly reduce exposure to the risk factors associated with operating a 1949 vintage pipeline at a transmission service stress level above 20% SMYS.

My testimony further explains that reducing the pressure of Line 1600 to below 20% SMYS will remove it from the scope of D.11-06-017, thus removing it from the scope of PSEP, reduce long-term overall risk consistent with both the California Public Utilities Commission's (CPUC or Commission) directives to enhance safety and the Transmission Integrity Management Program's (TIMP) requirement toward continual improvement, and avoid the potential pitfalls associated with pressure testing Line 1600. Indeed, as explained in the Prepared Direct Testimony of Neil Navin, the Utilities believe that pressure testing would be complex, potential complications may arise, and the customer impact would be difficult to manage.

Based on these difficulties and risk factors, the results of the in-line inspection (ILI) performed in 2012-2014, and sound engineering judgment, it is prudent to put a new pipeline in place to address Line 1600 for PSEP. The Utilities propose to construct a new pipeline – Line 3602 – to avoid any potential risks, complications, or customer impacts from pressure testing Line 1600 and maintaining Line 1600at a transmission service pressure level. The new Line 3602 will be pressure tested prior to being placed into service, as required under federal and state regulations.[3] Line 1600 will be de-rated to distribution service pressure level (*i.e.*, below 20% SMYS).

[3] *See generally* 49 Code of Federal Regulations (CFR) 192 and CPUC General Order 112-F.

II. CURRENT FITNESS OF LINE 1600 FOR SERVICE

A. Threat Categories and Manufacturing-Related Anomalies on Line 1600

Pipelines are inspected and maintained through operating and maintenance procedures on a routine basis. Under current federal regulations and as part of the Utilities' TIMP, additional assessments are conducted to identify potential threats to safe pipeline operation. These threats are categorized by nine potential failure modes, which are grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable.[4] Time-dependent threats are generally those related to corrosion and include external corrosion, internal corrosion, and stress corrosion cracking. Time-independent threats include third-party/mechanical damage, incorrect operational procedure, and weather related and outside forces such as earthquakes and landslides. Stable threats are manufacturing related, welding/fabrication related, or equipment related. Specific integrity assessments conducted to target manufacturing-related threats under the stable category are discussed below in Section II.B of my testimony.

Line 1600 was originally constructed in 1949 with predominantly electric flash-welded (EFW) pipe, and a small percentage of electric resistance welded (ERW) pipe. Electric flash welding of long seams is an obsolete form of pipe manufacturing where the longitudinal edges of heat-softened pipe are forced together to form a welded bond. Excess extruded material is then trimmed away, forming the classic "box-like" appearance of a flash-welded seam. This process was only utilized by a single pipe manufacturer – A.O. Smith Corporation, and production of pipe utilizing flash-welded seams was discontinued by 1969. Process control, material

[4] ASME B318.S-2004, section 2.2.

chemistry, and manufacturing-related factors all contribute to electric flash weld seam weld quality issues and related anomalies.[5]

The anomalies associated with EFW pipe are similar in many respects to the pre-1970 ERW manufacturing processes, where low frequency direct current welding of the long seam and manufacturing process issues combined to create a number of well-documented integrity concerns, including hook cracking, cold welds, non-metallic inclusions, susceptibility to selective seam corrosion, and variety of other related issues.[6] Among the more common types of anomalies listed, hook cracks associated with the EFW seam welds have been observed on Line 1600, and given the presence of both EFW and pre-1970 ERW long seams, interacting threats such as metal loss coincident with the seam weld (including corrosion interacting with manufacturing-related seam flaws, selective seam corrosion, and potential third-party damage) are threats that must be considered as part of a complete integrity assessment.

Hook cracks (also known as upturned fiber imperfections) take their name from the distinctive "J-shaped" flaw that results when metal separations in the steel skelp[7] that are originally oriented parallel to the skelp surfaces are forced together resulting in flow of the material toward either the inner or outer surface of the resultant weld.[8] Selective seam corrosion is preferential metal loss[9] that occurs at a weld bond line region or heat affected zone (HAZ).

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[5] Anomalies refer to unexamined pipe features which are classified as potential deviations from sound pipe material, welds, or coatings. All engineering materials contain anomalies which may or may not be detrimental to material performance.

[6] J.F. Kiefner and E.B. Clark, *History of Line Pipe Manufacturing in North America* (Kiefner 1996 Report), American Society of Mechanical Engineers (ASME) CRTD-Vol. 43 (1996).

[7] Skelp is wrought iron or steel that is rolled or forged into narrow strips and ready to be made into pipe or tubing by being bent (into a cylindrical shape) and welded.

[8] J.F. Kiefner with the assistance of the Interstate Natural Gas Association of America (INGAA), *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines, Department of Transportation Final Report 05-12R*) (Kiefner 2007 Report), Table A-1 (Apr. 26, 2007).

[9] Preferential weld corrosion refers to the fact that weldments are often more severely impacted by active corrosion than parent material. In other words, weld metal corrodes at a higher rate than the parent.

This phenomenon is promoted by localized galvanic differences in the weld and surrounding material, and when exposed to a corrosive environment results in the preferential attack of the weld area at an accelerated rate relative to the surrounding pipe material.[10,11] In other words, weld metal corrodes at a higher rate than the parent metal. Integrity management of Line 1600 includes (but is not limited to) monitoring of conditions such as selective seam corrosion, corrosion coincident with hook cracks, or other forms of interaction between threats such as third-party damage at otherwise stable defect locations.

B. Line 1600 Integrity Assessment History

In accordance with 49 CFR 192.921(a)(3) and 192.937(c)(1), two TIMP related assessments have been conducted on Line 1600: External Corrosion Direct Assessment (ECDA) in 2007 and in-line inspection (ILI, also known as "smart pigging") from 2012-2015.

1. External Corrosion Direct Assessment

The baseline assessment of pipe segments within High Consequence Areas (HCA) on Line 1600 was completed on February 23, 2007. Inspections were performed over approximately 20.7 miles, resulting in 11 examinations to investigate the likelihood of active external corrosion. External corrosion and third-party damage were not observed during examinations and no repairs were required.

2. In-Line Inspection

TIMP reassessment of Line 1600 was conducted utilizing a series of ILI surveys from December 2012 to December 2015. All pipe segments between the launcher and receiver (*i.e.*, HCA and non-HCA segments) were inspected using two types of ILI (*i.e.*, "smart pig") technologies:

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[10] Kiefner 2007 Report, at Table 3.
[11] Kiefner 1996 Report, at 5-4.

- Axial magnetic flux leakage (MFL), which is sensitive to volumetric flaws, such as metal loss caused by corrosion or third-party damage, and
- Circumferential magnetic flux leakage (CMFL) (a.k.a. transverse field inspection or TFI), which is sensitive to certain types of long seam flaws, such as selective seam corrosion and hook cracking.

a. In-Line Inspection Phases

ILI of Line 1600 was performed in three separate phases, primarily due to the break in geometric continuity created by the reduction in pipeline diameter from 16-inch down to 14-inch diameter (near the middle of the pipeline at Lake Hodges), and back up again to 16-inch diameter for the remainder of the pipeline. The phases are numbered from 1 to 3 in the chronological order of inspection. The inspection lengths, ILI tools utilized, and dates for each inspection phase are listed in Table 1 below.

TABLE 1
In-line Inspection Phases for Line 1600

<table>
<tr><th>Phase</th><th>Inspection Length (miles)</th><th>Inspection Extent</th><th>ILI tools</th><th>Assessment Date</th></tr>
<tr><td rowspan="2">1</td><td rowspan="2">29.1</td><td rowspan="2">Rainbow Metering Station to Lake Hodges</td><td>• Axial MFL
• Geometry</td><td>12/5/2012</td></tr>
<tr><td>• Circumferential MFL</td><td>2/6/2013</td></tr>
<tr><td rowspan="2">2</td><td rowspan="2">20.1</td><td rowspan="2">Lake Hodges to Mission Base</td><td>• Axial MFL
• Geometry</td><td>12/19/2013</td></tr>
<tr><td>• Circumferential MFL</td><td>3/20/2014</td></tr>
<tr><td>3</td><td>0.5</td><td>Lake Hodges</td><td>• Axial MFL
• Geometry</td><td>12/10/2015</td></tr>
</table>

b. In-Line Inspection Findings

The final reports for each of the ILI phases for Line 1600 identified anomalies: Phase 1 found 1,471; Phase 2 found 1,226; and Phase 3 found 85. Reported anomaly types and quantities for each phase are listed in Table 2 below. Due to differences in tool sensitivities, the quantity of anomalies listed for the CMFL tool for Phases 1 and 2 contain anomalies that were detected by the AMFL and Geometry tools (*i.e.*, anomalies were counted twice).

TABLE 2
In-Line Inspection Reported Anomalies

	Phase 1		Phase 2		Phase 3*
Reported Anomaly Type	**AMFL and Geometry**	**CMFL**	**AMFL and Geometry**	**CMFL**	**AMFL and Laser Deform.**
Crack-like	0	3	0	14	0
Deformation	47	116	28	33	0
Long Seam	123	265	100	198	0
Manufacturing	18	20	134	40	6
Metal loss	343	536	148	531	79
TOTAL	**531**	**940**	**410**	**816**	**85**

* The Applicants received the final report for Phase 3 in March 2016. At the time of this filing, planning to validate the ILI results was still in progress.

c. In-Line Inspection Based Repairs

For Phase 1 and Phase 2, a total of 62 direct examinations (excavations) of Line 1600 were conducted to validate the anomalies reported by the smart pigs. 19 examinations were either directly confirmed as hook cracking, or determined to likely be hook crack related. 6 examinations were performed at locations where crack-like anomalies were reported, and hook cracking was confirmed in all 6 locations. 13 examinations were performed at locations where manufacturing related metal loss was detected at the longitudinal seam, and hook cracking was confirmed at 4 locations, and determined to be likely for the remaining 9 locations.

Findings from all direct examinations resulted in the following remediation activities:

- 10 cylindrical replacements (totaling approximately 290 feet) to remediate[12] 1 mechanical damage defect and mitigate[13] 140 flaws (approximately 77% were longitudinal seam weld and base metal flaws related to the pipe manufacturing process),
- 39 repair bands to remediate 17 defects due to both mechanical/third-party damage and 68 nearby flaws (approximately 87% were longitudinal seam weld and base metal flaws resulting of the pipe manufacturing process), and
- 84 grind repairs to mitigate workmanship and base metal flaws resulting from the construction and manufacturing process

d. Current State of Line 1600

Assessment data from both ILI technologies demonstrate that for the remaining anomalies in Line 1600, adequate safety margins exist for operation at its maximum allowable operating pressure (MAOP) of 640 psig, which equates to a stress level of 39% of the specified minimum yield strength (SMYS).[14] The current MAOP at 640 psig reflects that fact that in 2011, the Utilities proactively reduced the pressure on Line 1600 to 80% of the historic MAOP of 800 psig (a 10% SMYS drop from the historic operating stress of 49% SMYS at 800 psig) in order to increase the margin of safety on the line.[15] The pressure reduction and resulting

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[12] "Remediate" is defined as an operation or procedure that transforms an unacceptable condition to an acceptable condition by eliminating the causal factors of a defect.
[13] "Mitigate" is defined as the limitation or reduction of the probability of occurrence or expected consequence for a particular event.
[14] *See* Section III below for an explanation of the significant of the percentage of SMYS (% SMYS).
[15] This pressure reduction was implemented July 13, 2011 as part of actions taken by the Utilities in response to the safety recommendations issued by the National Transportation Safety Board on January 3, 2011. Line 1600 was not subjected to a post-construction pressure test during its installation in 1949. In 2011, the pressure on Line 1600 was reduced from a historical MAOP of 800 psig, to a reduced pressure of 640 psig. *See* Report of Southern California Gas Company (U 904 G) and San Diego Gas & Electric

increased margin of safety serve as the basis for the confidence that the Utilities have in the current integrity of the pipeline. The benefits of a lower operating stress achieved through pressure reduction to 80% of a previous high pressure are noted in the excerpt below from a 2007 U.S. Department of Transportation (DOT) report on evaluating the stability of manufacturing and construction defects:

> [T]he analyses presented . . . show that a 20-percent reduction is almost as good as a test to 1.25 times MAOP. Therefore, for M [manufacturing] defects, it is a permanent demonstration of stability. Since this applies only to M defects and only if there are no interacting threats, the author believes that where the regulations that a pressure reduction is good for a year only, they are unnecessarily restrictive. The author believes this latter limit is meant to be applied to time-dependent defects only. Certainly, one cannot expect the margin demonstrated by a pressure reduction not to be eroded as time passes and corrosion or SCC [stress corrosion cracking] continues. Thus, if an operator were to opt for a pressure reduction to address M defects, that operator would still have to address other threats by appropriate integrity assessments after 1 year. The integrity assessment for corrosion and possibly for SCC as well could be done by in-line inspection, so that one-time pressure reduction could stand indefinitely for the demonstration of stability of M defects.[16]

C. PSEP's One-Time Risk Reduction Opportunity to Replace Line 1600

Although ILI results demonstrate that Line 1600 is fit for service, Line 1600 lacks a post-construction pressure test and must be pressure tested or replaced in compliance with PUC Section 958 and D.11-06-017. The State directive to pressure test or replace Line 1600 creates a unique and arguably one-time opportunity to permanently address the long-term risks associated with operating this 1949 vintage, non-state-of -the-art pipeline through the replacement of Line 1600's transmission function with a new pipeline. Conversion of Line 1600 to distribution service has the potential to create a significant reduction of EFW transmission service mileage,

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Company (U 902 G) on Actions Taken in Response to the National Transportation Safety Board Safety Recommendations (Apr. 15, 2011).

[16] Kiefner 2007 Report, at 41-42. While corrosion is a relevant risk for Line 1600, the line is not susceptible to SCC.

and represents a potential major step toward the Utilities' goals to reduce risk and drive system improvement, consistent with State directives.

Line 1600 is approximately 50 miles long, and about 46.5 miles (approximately 93%) are comprised of EFW pipeline segments. The Utilities operate six other transmission pipelines that contain pipe segments with a long seam that is confirmed to be EFW. As shown in Table 3 below, Line 1600 represents the largest mileage within this family of pipe. In total, Line 1600 comprises approximately 35% of the 133 miles of EFW in transmission service on the system.

TABLE 3
SoCalGas/SDG&E transmission pipelines that contain flash welded seams

Pipeline Name	Primary Install Date	Risk Score	Risk Ranking Among Flash Weld Pipelines	Mileage of Flash Weld Seams
1600	1949	349[17]	2†	47
1027	1949	311	6	33
85 NORTH	1931	359	1[18]	24
1004[19]	1944	349	2†	11
404	1944	317	4	11
49-18	1958	276	7	7
85 SOUTH	1931	313	5	<1

† *Two pipelines share an equal score, and are listed with the same ranking in the table. As a result, a ranking of "3" has not been assigned.*

Additionally, approximately 33 miles (approximately 60% of the total length) of Line 1600 traverses High Consequence Areas (HCA). Section III of my testimony describes the PSEP risk ranking methodology, but it should be noted that the ranking provided in Table 3 is not weighted

[17] The Line 1600 PIR score has been adjusted using a multiplication factor to reflect the existence of hook cracking in the flash-welded seam.
[18] Line 85 will also be addressed as part of PSEP. The Utilities are currently evaluating pressure test, replacement and de-rate alternatives for this line and intend to file a separate application for Commission review and approval of a proposed Line 85 project, once this analysis is complete.
[19] Line 1004 is managed within the TIMP, and is subject to the assessment and maintenance requirements governed by that program. Additionally, portions of Line 1004 are included within the scope of PSEP.

by length of EFW pipe, and does not reflect the fact that Line 1600 contains the largest mileage of flash-welded pipeline in the transmission system.

The Utilities have a long-standing history of working toward solutions that reduce or eliminate the risks associated with different families of pipe. For example, over the course of the Utilities' operating history, they implemented several major efforts to eliminate both cast iron pipe and copper pipe within the system. Under the Distribution Integrity Management Program (DIMP), the Utilities are currently targeting Aldyl-A plastic pipe with known risk factors in order to reduce the risk of failures on the distribution system. Line 1003 is a non-state-of-the-art pipeline that contains approximately 16 miles of EFW pipe segments and was formerly operated in Transmission service. In an effort to enhance system safety, Line 1003 was converted to distribution service in the same matter that is proposed in this proceeding for Line 1600. Line 1600, while safe for service, should be similarly considered for such risk reduction efforts, especially in light of the fact that Line 1600 has a known hook cracks along its EFW long seam. Given that Line 1600 contains the largest mileage of A.O. Smith pipe on the system, operates at a transmission service level, and is located in HCAs, it would be prudent for the Utilities to take this opportunity to significantly and permanently reduce long-term risks associated with this vintage, non-state-of -the-art pipe by permanently lowering its operating pressure.

For Line 1600, and generally for pipelines with similar risk factors, the Utilities have established a 20-year time frame as a reasonable expectation to evaluate either repurposing of transmission lines to distribution service or replacement. This time frame is based upon engineering judgment, and depends upon a number of factors that would ultimately include coating degradation, cathodic protection performance, time-dependent threat growth, leakage maintenance program demands, and time-independent threat rates.

Even if Line 1600 is pressure tested, it is prudent to assume that it will need to be replaced eventually. While the Utilities are confident in the ability of ILI technologies to detect seam flaws that can potentially result in failures, if Line 1600 is pressure tested instead of replaced under PSEP, on-going integrity assessments under the transmission integrity management plan will be required to monitor remaining seam anomalies for potential future in-service growth and/or interaction with any conditions that may activate potential failure in what are otherwise stable flaws. Moreover, assessment methodologies that primarily target the likelihood of failure component of risk do not substitute for the universal risk benefits afforded through pressure reduction, since a defect's likelihood of failure, consequence of failure, and overall future risk are all positively impacted (*i.e.*, reduced) through pressure reduction. As explained in Section III below, if Line 1600 is pressure tested and maintained at a transmission service stress level, anomalies that survive the pressure test will be exposed to an increased potential of failure and higher overall risk compared to operation at lower stress levels.

III. RISK-BASED METHODOLOGY FOR TESTING OR REPLACING LINE 1600

A. Pipeline Integrity Risk

The operating stress level of a pipeline has a significant influence on overall pipeline risk because the stress in the pipe wall contributes to both the likelihood of failure and the consequence of failure. Pipeline risk is commonly defined as the product of the likelihood of failure (LOF) and the consequence of failure (COF), or Risk = LOF x COF.[20]

[20] Risk here is determined in accordance with ASME B318.S-2004, section 5.2. Failure as used in the risk equation is defined in ASME B318.S-2004, section 13 as a "general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is [sic] has become unreliable or unsafe for continued use.

Likelihood of failure is closely related to the specific characteristics and anticipated threats of each pipeline segment. For the majority of pipeline threats, the LOF is governed by the ability of a defect to resist the applied load (with load usually described as either pressure, or as % SMYS at MAOP). In other words, as long as the weakest defect is able to resist the maximum operating pressure, then no failure will occur. A critical defect is one that would be expected to fail at MAOP, and there is an inverse relationship between % SMYS at MAOP and critical defect size. As the % SMYS increases, the LOF also tends to increase because smaller defects become subject to failure.

Consequence of failure is related to the energy in each pipeline and the population density near a pipeline that may be affected by a failure. Potential impact radius (PIR) refers to the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property and is dependent upon the pipeline's diameter and MAOP.[21] PIR increases proportionally with % SMYS, and a larger PIR typically affects proportionally larger numbers of people, and in this manner, calculation of the segment-specific PIR serves as a proxy for COF. PIR thus provides an effective means to rank segments by their potential energy and possible effect on population density. PIR also assumes a full guillotine fracture at any point along the pipeline segment, which is a failure mode representative of a "rupture," as opposed to a "leak," where only a small volume of gas is released. Pipelines operating at stress levels above 20% SMYS, and especially above 30% SMYS, are at much greater risk of developing a rupture

[21] Potential impact radius is determined in accordance with 49 CFR §192.305 Definitions: *Potential Impact Radius* (PIR). PIR is determined by the formula r = 0.69* (square root of ($p*d^2$)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the MAOP in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

(or sometimes a propagating fracture) as opposed to a "leakage" failure, as compared to pipelines operated at stress levels below 20% SMYS.[22]

As explained above, assessment data from ILI devices (*i.e.*, "smart pigs") indicate that adequate safety margins exist on Line 1600 for operation at its MAOP of 640 psig. Despite the Utilities' confidence in the TIMP-based management of risks associated with long seam flaws using existing assessment data, it must be acknowledged that no pig or inspection method is perfect,[23] this line lacks a post-construction pressure test, and ongoing assessment will be required to inspect any potential future flaw growth. Based on the risk factors of potential impact radius, long seam factor, and higher % SMYS at MAOP, Line 1600 would exhibit higher risk factors if pressure tested and maintained at a transmission service stress level. Pressure testing would only address the likelihood of failure portion of the risk equation, whereas pressure reduction would simultaneously reduce the likelihood of failure and also significantly and permanently reduce the consequences of failure.

B. Potential Impact Radius (PIR)

One of the ways in which pressure reduction on Line 1600 would reduce the consequences of failure is by reducing the PIR, in other words, shrinking the area affected by a

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[22] *See* B.N. Leis et al., *Leak Versus Rupture Considerations for Steel Low-Stress Pipelines*, Battelle Final Report GRI-00/0232, at 32 (Jan. 2001):

> Given the results generated, the leak to rupture transition for corrosion defects in the low-wall-stress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents. Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to full-scale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents possess toughness [sic] indicated a threshold on order of 25 percent of SMYS.

[23] There are various contributing factors for tool performance issues, but among those related to ILI crack detection are the ability of ILI to accurately size anomalies, and more importantly, the observation of cases where ILI missed anomalies that were within the detection limits of the tools used. *See* J.F. Kiefner et al., *Track Record of In-line Inspection as a Means of ERW Seam Integrity Assessment* (Kiefner 2012 Report), Battelle Final Report No.12-180, at 120-121 (Nov.15, 2012).

potential release of gas. A larger PIR typically affects proportionally larger numbers of people, and in this manner, calculation of the segment-specific PIR provides an effective means to rank segments by their potential energy and possible effect on populations. Conversely, a reduction in MAOP will result in a proportional reduction in the PIR, exposing fewer people to the potential negative consequences of a pipeline failure. Based on Line 1600's diameter of 16 inches and current MAOP of 640 psig, Line 1600 has a larger PIR as compared to the PIR calculated at its proposed distribution service MAOP of 320 psig (279 feet versus 198 feet respectively; resulting in a potential PIR reduction of 81 feet). As discussed in the following sections, a reduced MAOP not only provides the benefit of a smaller PIR, it also reduces overall risk when coupled with the benefit of a reduced likelihood of failure.

C. Long Seam Flaws

The Utilities apply "long seam factors" to raise the score for certain pipeline segments, as specified in 49 CFR 492.113. As explained below, remnant long seam flaws are a risk factor for Line 1600 if pressure tested and maintained at a transmission service stress level.

Non-state-of-the-art pipelines commonly contain imperfections, and typically these imperfections can remain safely in service as long as they do not become destabilized by forces acting upon them or by growth of the imperfections to a critical size at operating pressures. The typical modes of failure for both EFW and pre-1970 ERW long seams are straight-away failure at or near MAOP, cyclic fatigue, and pressure reversals – with the latter two mechanisms being fairly uncommon for natural gas pipeline systems.[24]

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[24] Cyclic fatigue is a material degradation mechanism that progresses through the gradual extension of a crack that initiates at pre-existing flaws (seam flaws being among the most susceptible). The action of pressure cycling in a pipeline provides the force required to gradually extending the crack depth and length until it grows to a critical size. Cyclic fatigue is typically considered an uncommon occurrence in typical natural gas pipeline systems. A third type of failure is a pressure reversal, which is a specific

Pressure testing to sufficient levels effectively eliminates the likelihood of failure for critically-sized flaws by removing the population of flaws that would experience straight-away failure—because flaws of a critical size and larger would have failed during the pressure test. While this benefit is effective for the immediate demonstration of the pressure carrying capability of a pipeline, the benefits of pressure testing do not carry into the future since sub-critical flaws may remain in the pipeline after completion of a test that may be exposed to destabilizing events. Known hook cracks associated with the EFW seam welds have been observed on Line 1600 and anomalies that remain after repair must be periodically monitored for degradation or interaction with other threats. Specifically, this would include the interaction between the flaw and any time-dependent threat (*e.g.*, corrosion and selective seam corrosion) and any time-independent threat (*e.g.*, accidental over pressurization, third-party damage, and earth movement). In each case, the likelihood of failure increases due to either exposure to time-independent loads or the growth of remaining flaws, both of which eventually lower the pipe's ability to resist failure. To reflect the increased risk exposure, the Utilities adjusted the long seam factor that contributes to the risk ranking of Line 1600 shown in Table 3 to account for potential undetected seam anomalies and known hook cracking.[25]

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failure mechanism where a defect fails at a pressure lower than the previous high pressure that it has survived. The lower failure pressure is ultimately the result of damage caused by the previous high pressure and/or the action of depressurization from the high pressure. Kiefner 2007 Report, at 21. Pressure reversals are considered a low probability occurrence in most natural gas pipelines and therefore are assumed to be rare enough to be eliminated from consideration as a risk on Line 1600.

[25] Per 49 CFR Part 192.113, electric flash welded long seams are assigned a longitudinal joint factor of 1.0. To account for the long seam hook cracking that has been observed in the EFW seams on Line 1600, and consistent with a conservative approach to risk evaluations based on feedback from pipeline assessment data, a longitudinal joint factor of 0.8 was used in lieu of 1.0 as a conservative approach to reflect the condition of these pipe segments in the risk scoring.

i. Pressure Reduction Greatly Reduces the Likelihood of Failure for a Critical Flaw

Pressure reduction increases the margin of safety between the critical flaw at a lower MAOP and the demonstrated level of operating service at the higher MAOP. In addition to the margin of safety created by pressure reduction, the likelihood of failure is greatly reduced since a lower MAOP has the effect of increasing the size at which a flaw is classified as critical. Figures1 and 2 are defect failure curves for both the EFW and pre-1970 ERW seams at 800 psig, 640 psig, and 320 psig (the historic, current, and proposed reduced pressures, respectively). These charts show a family of curves that provide combinations of flaw depth, length, and the corresponding estimated failure pressure. Also shown on the charts are the leak versus rupture boundaries, which define the flaw depth and length combinations that define when a critically-sized flaw at a given pressure will transition from a leakage failure mode to a rupture failure mode.

FIGURE 1
Comparison of critical flaw sizes for hook cracks in the EFW seam weld at 800 psig, 640 psig, and 320 psig.

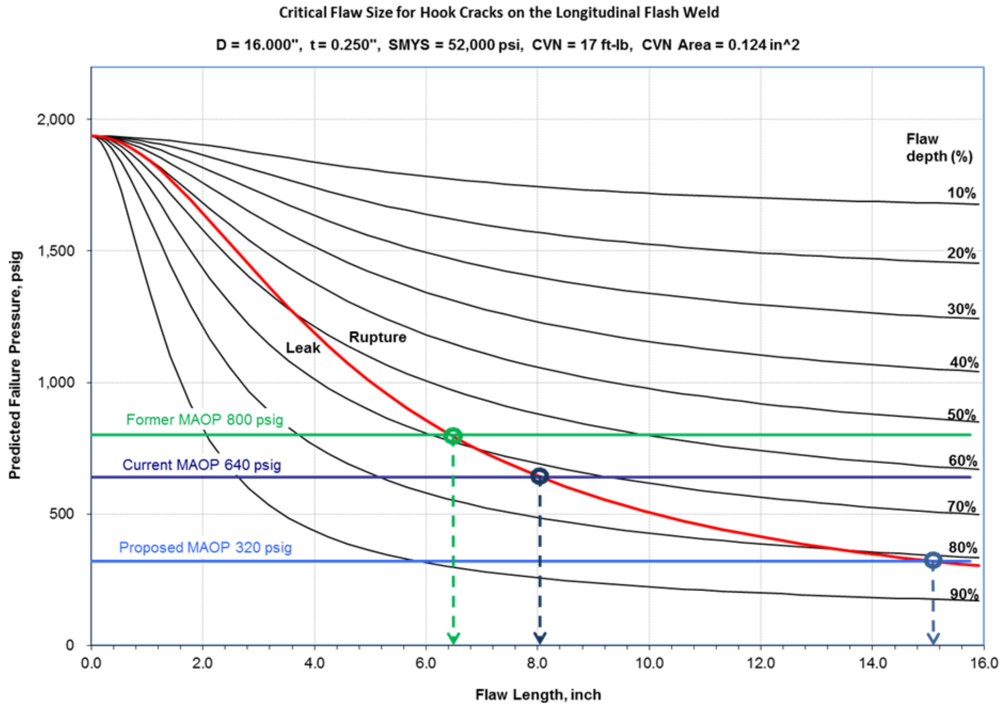
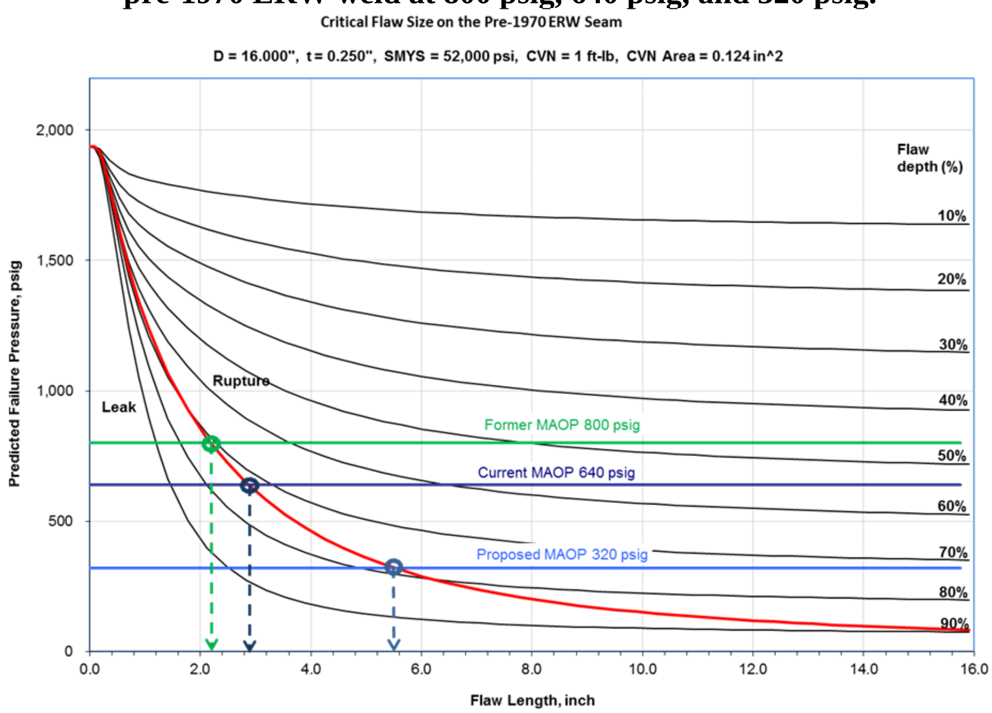


FIGURE 2
Comparison of critical flaw sizes for bondline flaws in the pre-1970 ERW weld at 800 psig, 640 psig, and 320 psig.



The summarized results from both charts shown in Table 4 demonstrate a significant increase in the critical flaw size at the leak/rupture boundary associated with the proposed pressure reduction from 640 to 320 psig.

TABLE 4
Comparison of Leak/Rupture Boundary Critical Flaw Size at Various Pressures

	Flash Weld Seam		**ERW Seam**	
Pressure	**Depth (%)**	**Length (in)**	**Depth (%)**	Length (in)
800	68	6.5	72	2.2
640	73	8.0	73	2.9
320	82	15.1	77	4.6

As demonstrated in Table 4, pressure reduction increases the margin of safety for a critically sized flaw on the leak/rupture boundary by increasing the size of flaw necessary to initiate rupture. The increase in critical flaw size not only improves safety, but also enhances detectability and prolongs the time to failure for all time-dependent threats. As a result, pressure reduction significantly and permanently reduces both the likelihood of failure and the consequences of failure, and provides a greater overall risk reduction than pressure testing alone.

ii. Limitations of Existing Assessment Data and of Pressure Testing

Despite the Utilities' confidence in their TIMP and existing assessment data, no single technology, tool, or set of inspection data is perfect, and a higher level of reliability can at times be achieved through complementary methods, used in conjunction with in-line inspection, such as pressure testing, pressure reduction, and/or replacement. This approach to system integrity is consistent with the Consumer Protection and Safety Division (CSPD) (now Safety and Enforcement Division) report on the Utilities' PSEP, where the Utilities' proposal to implement circumferential magnetic flux leakage as a viable and cost-effective alternative to pressure testing was described as less desirable than an approach that utilizes multiple complimentary methods.[26]

CPSD's observations were mirrored in a 2012 report to the DOT that studied the reliability of smart pigs to detect seam anomalies for 13 in-line inspection runs using tools capable of seam integrity assessment. The report provides three recommendations for verification of smart pig seam anomaly performance, and notes that pressure testing is a complementary method to seam-related in-line inspection verification.[27] As such, it should be acknowledged that smart pigging technology can experience diminished flaw detection and measurement errors, and even the best available non-destructive assessment technologies require validation to manage potential shortcomings. Additionally, the same report on ILI seam inspection performance noted that: "Among the 13 cases examined, there was no case for which the investigating team is willing to say that the inspection provided full confidence in the seam integrity of the assessed segment."[28]

Consistent with these experiences, the Utilities recognize the value of both pressure testing and pressure reduction as viable options for mitigating seam flaws that may remain in service, particularly for non-state-of-the-art pipelines, as evidenced by the initial pressure reduction on Line 1600 to 640 psig.[29] The benefits of pressure testing are well documented, and

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[26] *See* Technical Report of the Consumer Protection and Safety Division Regarding the Southern California Gas Company and San Diego Gas and Electric Company Pipeline Safety Enhancement Plan, at 17 (Jan. 17, 2012):

> CPSD does not agree that the proposed alternative methods provide an equivalent basis for the strength testing required by D.11-06-017. . . . CPSD believes that because these alternatives, like pressure testing, have recognized strengths and weaknesses, they should be used to complement pressure testing of pipelines, as required by D.11-06-017, and not as a substitute for it.

[27] Kiefner 2012 Report, at 120-121.

[28] *Id.* at ES1.

[29] Line 1003 is another example of a non-state-of-the-art, flash welded pipeline that formerly operated in transmission service, but has been converted to distribution service in the same manner that is proposed for Line 1600.

while pressure testing is a technically feasible option for validating seam integrity, there are a number of significant practical complications that make the pressure test option less suitable for Line 1600.

Pressure testing removes a wide range of defects, and when conducted to a sufficiently high level, will cause critically-sized defects to fail, allowing for their detection and repair prior to pipeline commissioning. While the Utilities are confident in the safety of Line 1600, pressure testing will expose the pipeline to pressure levels well in excess of pressures experienced in-service. Knowledge obtained though in-line inspection will allow the Utilities to proactively mitigate detected pipeline anomalies that could lead to a potential pipeline failure at higher pressure test levels. However, proactive mitigation of anomalies prior to testing is dependent upon the limitations of smart pigging to successfully detect and size critical flaws. Indeed, industry reports have noted the potential for ILI limitations with regard to accurately sizing anomalies and detecting all anomalies within the detection limits of the tools.[30] Significantly, any flaws not detected or sized correctly by smart pigging that are large enough to fail during pressure testing, have the potential to spiral into a test-repair-retest cycle.

Flaws that are particularly difficult to detect usually have some or all of the following characteristics: 1) axially oriented, 2) small in size (depth, length, or both), and 3) circumferentially narrow (such as tight bondline flaws). For EFW and pre-1970 ERW seams, flaws with these characteristics typically include cold welds, penetrators, hook cracks, inclusions, pinholes, stitching, and weld cracks, including fatigue cracks. Predicting or anticipating the potential to miss these flaws during inspection is difficult, due to the fact that the flaws in question are inherently unknown or unreliably sized as a result of the technological

[30] Kiefner 2012 Report, at ES3.

limitations of the smart pigs.[31] Avoiding the need to pressure test Line 1600 would prevent the pitfalls associated with entering into an unpredictable cycle of pressure test failures.

Additionally, the benefits of pressure testing are limited for construction or fabrication flaws present in non-state of-the-art pipeline materials – particularly at girth welds, and flaws that are too small to fail the pressure test. Pressure testing will not remove these features, and the Utilities will still have an obligation to monitor and maintain these features for the lifespan of the pipeline to prevent and mitigate future flaw growth and/or interaction with any conditions that may lead to failure. Such monitoring and maintenance could be avoided if the line's pressure is instead lowered to operate below 20% SMYS.

It should also be noted that a pressure test demonstrates the pressure carrying capability of the pipeline at the time of the test, but provides no assurance of future integrity after the successful completion of a test. Future flaw growth and/or exposure to potential failure can take a number of forms, from wall loss due to selective seam corrosion active at or near the weld bondline, to outside force (such as third-party damage) resulting in denting/gouging coincident with a seam weld anomaly, and possible outside force from ground movement inducing strain on flaws that are otherwise benign. Reducing the pressure on Line 1600, in contrast to pressure testing, will mitigate the risk of future flaw growth and potential failure related to the de-stabilization of what would otherwise be considered stable manufacturing and construction flaws, as discussed in Section D below.

[31] In the Kiefner 2012 Report on ILI for seam integrity assessment, three of the cases studied involved the review of CMFL runs, the same technology used to inspect Line 1600. In one case that compared ILI findings and hydrostatic test results, four leaks and one rupture occurred during spike pressure testing that followed ILI using CMFL. Additionally, one hook crack exhibited evidence of crack growth that was attributed to the commissioned pressure test and subsequent retests. *See* Kiefner 2012 Report, at 102-103.

Some time-independent threats (notably third-party damage and outside force due to earthquakes) are additional examples potential future threats not mitigated through pressure testing since failure is not based upon a predictable rate and often can occur anywhere along the pipeline. Every pipeline has some exposure to outage and/or failure due to one or more of the threats previously mentioned, and as a result, every pipeline has the potential to experience service disruption.

iii. Pressure Reduction Greatly Reduces the Consequences of Failure for a Critical Flaw

On the consequences of failure side of the risk equation, pressure testing would have no benefit. By de-rating Line 1600, the drop in pipeline stress would have a large impact on the mode of failure for a long seam flaw – specifically on the leak versus rupture characteristics of a critically-sized flaw, as explained in the next Section below on the % SMYS.

D. Percentage of SMYS (% SMYS)

Another risk factor in determining the likelihood and consequence of failure is the % SMYS that a pipeline experiences at MAOP. Accordingly, a pipeline segment that operates at a higher % SMYS at MAOP is given a higher priority under the Utilities' PSEP. Risk, both the likelihood of failure and the consequence of failure, increases with increasing pipe wall stress level. With regard to LOF, increasing % SMYS has the effect of causing smaller defects to fail due to decreasing critical defect size. This lowers the failure initiation threshold and increases likelihood of failure. With regard to COF, once a failure has initiated, the mode of pipeline failure (typically expressed as leak versus rupture) is significantly affected by pipeline stress. The likelihood of propagating fractures, which are associated with pipeline rupture, is significantly reduced in pipelines that operate at a lower % SMYS, and particularly, below the 20% SMYS threshold.[32]

The Utilities already reduced the MAOP of Line 1600 from 800 to 640 psig to increase the margin of safety. The Utilities' action of lowering the MAOP to 39% SMYS significantly and permanently reduced the integrity risks associated with the pipeline. ILI-related repairs coupled with the reduced operating pressure on Line 1600 have already significantly increased the safety margin. Lowering the pressure further so that Line 1600 operates below 20% of the SMYS would create an additional safety margin beyond that already implemented by the Utilities and would effectively nullify the risk of rupture.

Nonetheless, the long-term benefits of pressure reduction that apply to manufacturing-related defects like seam flaws do not permanently extend to time-dependent threats like corrosion. Likewise, the short-term benefit of pressure testing would eventually "expire" for time-dependent threats, since at some point the passage of time will expose the pipeline to threats such as corrosion. Though the eventual "expiration" of benefits related to time-dependent threats is common to both the pressure testing option and the de-rating option, the overall risk benefits from de-rating still outweigh the risk benefits from pressure testing, given that both likelihood of failure and consequence of failure are reduced by lower operating stress:

> Because pressure drives both fracture initiation and fracture propagation, low-wall-stress pipelines have different failure characteristics than pipelines operating at high stress levels. Moreover, pressure is a key factor in determining leak versus rupture response in the event of fracture initiation. Finally, the extent of thermal exposure depends directly on pressure. For these reasons, critical defect sizes are large in low-wall-stress pipelines, most failures will result in leak rather than rupture. It takes a very large defect to initiate a leak or rupture and it is unlikely that fracture will propagate. These differences significantly reduce the

[32] E.B. Clark et al., *Integrity Characteristics of Vintage Pipelines*, Appendix B (Oct. 2004).

> potential likelihood and consequences of an incident for such pipelines in comparison to higher stressed pipelines.[33]

The likelihood of failure and consequence of failure are significantly tempered for stress levels < 20% SMYS.[34] For this reason, the Utilities advocate a permanent reduction in pressure on Line 1600 to 320 psig, or just under 20% SMYS. The 20% SMYS threshold is a recognized lower bound for low stress transmission pipeline per CFR Part 192.3. An American Gas Association report from 2001 summarized the findings of three Gas Technology Institute studies that showed the likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions are reasonably expected to occur below 20% SMYS.[35, 36] As a result, the Utilities would permanently reduce the overall risk exposure of Line 1600 to a level that is as low as reasonably practicable, particularly when compared to operation above 20% SMYS, where failures start to trend toward modes characteristic of transmission service (namely, smaller critical defect sizes that in turn increase the likelihood of failure, and the consequences of failure related to larger PIRs and increased susceptibility to rupture).[37] Thus, even for time-dependent threats such as corrosion, on-going management after pressure testing is still necessary. De-rating the line would significantly reduce the risk management of those time-dependent threats because no rupture conditions would reasonably be expected. Figures1 and 2 in the Section above show the leak versus rupture curve for the EFW and pre-1970 ERW seams at 800 psig, 640 psig, and 320 psig. As shown, the likelihood of rupture versus a leak decreases with the proposed pressure reduction from 640 to 320 psig.

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[33] *Id.*
[34] Leis, *supra*, at 22.
[35] *Integrity Management Considerations for Low Stress Natural Gas Transmission Pipelines in High Consequence Areas*, American Gas Association (Feb. 2001).
[36] Clark, *supra*, at 32, Appendix B; Leis, *supra*, at 22.
[37] *See* Leis, *supra*, at 22.

Rather than abandon Line 1600, the Utilities propose to repurpose the line for distribution service to prevent the need to build additional infrastructure to connect the taps of Line 1600 to the new Line 3602. Instead of performing a pressure test, the Utilities will reduce Line 1600's MAOP to a level where the resultant safety margin in distribution service, as compared to the pipeline's demonstrated pressure carrying capability, is greater than the safety margin that would result from the pipeline operating at a transmission service stress level after a pressure test. Additionally, the lower operating pressure resulting from conversion to distribution service will permanently and significantly reduce exposure to all risk factors where the likelihood of failure and the consequences of failure are affected by operating stress. In this way, while simultaneously avoiding the cost and difficulties of connecting to a new pipeline, long-term pipeline safety would be enhanced to a level greater than that achievable with a pressure test, given the greater overall risk reduction that results from lower stress operation. This proposed approach is consistent with TIMP objectives toward the demonstration of continuous improvement, and the regulatory drive toward zero accidents.

In order to continue operating at a transmission service stress level, Line 1600 must either be pressure tested or replaced as part of PSEP. As discussed above, the proposed construction of a new replacement line and conversion of Line 1600 to distribution service would satisfy State requirements (by reducing the MAOP of Line 1600 from transmission service) in a manner that further enhances safety.

IV. QUALIFICATIONS

My name is Travis T. Sera. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. My current position is Pipeline Integrity Manager. I joined SoCalGas in 1995 and have held various positions of increasing responsibility within the Gas Engineering and System Integrity department. I left SoCalGas briefly, from 2003 to 2005, and during this time held the title of Senior Consulting Engineer for Structural Integrity Associates, an engineering consulting firm to the nuclear, petro-chemical, and pipeline industries. I have been in my current position at SoCalGas since 2012.

My responsibilities include oversight of the pipeline integrity assessments and resultant engineering analysis conducted on the transmission pipeline system including: metallurgical evaluations, defect analysis, and repair recommendations.

I have a Bachelor of Science degree in Materials Engineering from California Polytechnic State University - San Luis Obispo, and I am a registered Professional Metallurgical Engineer in the State of California.

I have previously testified before the Commission.

This concludes my prepared direct testimony.