Applicant No: A.11-09-XXX
Exhibit No:
Witness: Oliver Moghissi

In the Matter of the Application of Southern California Gas Company (U 904 G) For Approval to Retain Its Current Rule 30 Gas Delivery Specifications.	)))))	Application 11-09-XXX (Filed September 2, 2011)

PREPARED DIRECT TESTIMONY

of Oliver C. Moghissi

Det Norske Veritas (U.S.A.) Inc. (DNV)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
September 2, 2011

I. INFORMATION CONSIDERED

I reviewed and considered publically available information including technical and industry standards (e.g., NACE & ASME). I also relied on my personal education and experience related to corrosion engineering and risk management.

II. OPINIONS

It is my opinion that increasing the content of carbon dioxide, CO_2, from the present standard of less than 3% increases the likelihood of pipeline failure from internal corrosion, thereby increasing the risk of operating the pipelines of interest and those that carry the gas at downstream locations. Likewise, that increasing the content of oxygen, O_2, from the present standard of less than 0.02% increases the likelihood of pipeline failure from internal corrosion, thereby increasing the risk of operating the pipelines of interest and those that carry the gas at downstream locations.

A. Internal Corrosion Risk Increases with CO_2 Concentration

The risk of internal corrosion due to CO_2 increases with concentration because the corrosion rate due to CO_2 increases with concentration. Risk can be characterized by the probability of failure (PoF) multiplied by the consequence of failure (CoF). To quantify risk, the probability that water exists can be multiplied by the probability of failure (as determined by CO_2 corrosion rates).

Despite differences in how CO_2 corrosion rates are calculated, it is clear that rates are increased by increasing CO_2 concentration. CO_2 corrosion rate of carbon steel is one of the most thoroughly studied topics in oil and gas equipment corrosion. Many different models exist, and all are limited by the underlying assumptions made to simplify the system. Actual corrosion rates in natural gas pipelines are difficult to accurately predict because of the complex environment; factors such as the nature of the scale inside of a pipeline, the interaction of multiple corrosive gases (e.g., H_2S and O_2), the water chemistry, the existence of liquid hydrocarbons, and geometries such as crevices need to be considered. In addition, corrosion rates are known to have a distribution with extreme values that are not predicted by commonly used corrosion rate models.

Corrosion rates predicted by most models predict a theoretical, mean, or median corrosion rate. In an actual pipeline, it is clear that corrosion does not occur uniformly at an average rate.

Internal corrosion in pipelines typically occurs at a low rate over the majority of its length and circumference. It is the extreme value, not normally predicted by models, that creates the integrity threat. Because of this, managing the internal corrosion threat in pipelines usually involves minimizing the rate rather than accepting a low rate.

A factor to consider when evaluating if a short term exposure to high corrosion rates is acceptable is that corrosion is cumulative over time. While a 10mpy rate might seem acceptable within a 1-year perspective, it is unacceptable when considering multiple short term exposures of 10mpy over the design life of a pipeline. Since many pipelines are already beyond their original design life and are expected to be used for many years in the future, minimizing corrosion in an aging pipeline infrastructure is standard practice.

B. Internal Corrosion Risk Increases with O_2 Concentration

Oxygen corrosion contributes to pitting corrosion, significantly reduces the effectiveness of corrosion inhibitors, and greatly accelerates corrosion caused by other corrodents (such as carbon dioxide) that are typically present in natural gas. Oil and gas production companies typically limit the dissolved oxygen in oilfield water injection systems to no more than 10-50 ppb in the water phase. The concentration in the water phase is related to the gas phase concentration and depends on pressure and temperature. A 10 ppb water phase concentration will result in a pipeline at 60°F and 400 psi and 35 ppm oxygen fraction in the gas phase (0.0035%).

Moreover, PRCI PR-15-9313, "Carbon Dioxide/Hydrogen Sulfide Corrosion under Wet Low Flow Gas Pipeline Conditions in the Presence of Bicarbonate, Chloride, and Oxygen," page 4-1, affirms that:

> Oxygen in natural gases at concentrations as low as 100 ppmv can cause pitting of carbon steel. Pitting rates on the order of 100 mpy can occur. No other corrosive species (e.g., CO2 or H2S) are required for such severe pitting to occur . . . . Literature references suggest that limiting oxygen concentration to no more than 10 ppmv may be sufficient to reduce oxygen-induced corrosion in gas transmission pipelines to acceptably low levels.

This PRCI report supports the conclusion that, even at levels this low, oxygen poses a corrosion problem.

C. Specifying Dry Gas Does Not, By Itself, Eliminate Corrosion Threat

The existence of dry gas specifications is insufficient to remove the threat of internal corrosion. Internal corrosion failures have occurred in natural gas transmission pipelines despite these specifications. Even with aggressive gas quality monitoring, an upset can occur that increases the probability of pipeline damage and failure. The incident database of the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration has documented many such internal corrosion failures, and internal corrosion damage has been detected within the Southern California Gas system. Additionally, it should be considered that a particular gas determined to be non-corrosive in a particular pipeline segment might be corrosive when transported to another location within a gas distribution network.

Corrosion cannot theoretically occur without the presence of an electrolyte, but corrosion has been detected in pipelines carrying gas specified to be above the dew point. If no electrolyte to support corrosion exists in a pipeline, the fraction of CO_2 or O_2 is irrelevant, and no specification of maximum CO_2 or O_2 concentration is required on the basis of corrosion. Since corrosion has been observed and specifications require the absence of liquids, electrolytes find their way to the pipe wall through one of several possible mechanisms.

- The simplest explanation is that gas at (or near) the water dewpoint enters the pipeline. This gas would typically contain more water than the maximum specified and episodically enter the pipeline undetected (especially when continuous dewpoint monitoring is not used). Even if the water does not condense where it enters the system, it may condense 1) at locations of lower temperature such as cooling after compression or under a river, or 2) in downstream piping at higher pressures in a system where gas moves around a network based on supply and demand rates.
- Another simple explanation is carryover of liquid (i.e., 'free') water from upstream facilities or a tie-in. These upsets also exceed both existing and proposed gas quality specifications. This liquid accumulates at isolated locations (e.g., at the bottom of inclines) and allows corrosion to occur until it evaporates. Short episodic upsets can be difficult to detect, and the water typically cannot be removed except by evaporation over time with dry gas.
- A future source of water is from hydrostatic pressure testing. Because of recent industry incidents and changes in regulations, portions of SoCal's pipeline system (or systems connected to SoCal) will require hydrostatic pressure testing. While use of this pressure

testing will allow identification of possible defects (i.e., those that fail at the test pressure), it also introduces water to systems that were previously dry. Some of this water is expected to remain in the system despite efforts to dry the line.

- Another possible occurrence is the carryover of glycol, usually by mist, downstream of dehydration facilities. Glycol absorbs water and supports corrosion. The corrosion rate of glycol/water mixtures are typically lower than with only water, but glycol should not be considered to prevent corrosion unless it is specifically dosed with a corrosion inhibitor.
- In much of SoCal's pipeline system, gas quality is monitored monthly. For those pipelines, it is reasonable that episodic input of water will not be detected. This means that increased risk from higher concentrations of CO_2 (or O_2) will not identified and therefore will not be mitigated.
- Once water enters a system, it can remain for extended periods at locations where evaporation rates are restricted (i.e., the liquid surface is not exposed to flowing gas). These locations include deposits on the pipe wall or pipeline fixtures that trap water.
    - Examination of the internal surface of in-service gas pipelines typically shows the presence of a film. This film covering the metallic pipe wall has either been grown (e.g., by corrosion product or microbial activity), or it has been entrained by the gas to a location and then deposited. Depending on the character of the film, water carried to a particular location can become trapped under solids and remain wet. By this mechanism, an apparently dry gas system can retain isolated wet locations that support corrosion.
    - A pipeline system typically contains a variety of fixtures that can trap water and subsequently restrict evaporation. These fixtures include drips, stub ends, and valves. These fixtures operate at full line pressure and are susceptible to integrity threats from internal corrosion. Even if the water dew point measurements show dry gas, water can exist at these locations and support corrosion.
    - Water can condense on the pipe wall and support corrosion even when the gas is above the water dewpoint. Hygroscopic solids will attract water and can allow corrosion to occur. Deliquescent solids will attract water and liquefy even when the atmosphere around them is above the water dew point. The critical humidity at which water will condense depends on the character of the solid surface. While

it is not known exactly what the critical water content in natural gas results in deliquescence of typical films inside pipelines, the evidence supports the conclusion that water will form on the pipe wall before the gas is saturated with water (i.e., above the dew point). In this way, internal corrosion can occur in a system with gas above the water dewpoint.

D. The Most Reliable Way to Manage Corrosion Risk Is to Minimize the Likelihood and Concentration of Corrodents

The most reliable way to reduce CO_2 and O_2 corrosion in natural gas is to reduce their concentrations to a level of low corrosivity. If this is not possible, several options exist to reduce risk including mitigation, monitoring, and inspection. All of these options have an associated cost.

The risk associated with CO_2 or O_2 corrosion can be reduced by actions such as reducing the likelihood of water in the pipeline (e.g., continuous monitoring and ability to prevent the acceptance of gas exceeding specifications), initiating corrosion inhibition, introduction of corrosion monitoring tools (e.g., coupons at locations where water might accumulate), increasing inspections (or their frequency), and repairing any corrosion damage that might lead to failure. It is also possible to evaluate total risk of a pipeline segment and optimize actions taken for all threats. For example, it is possible to compensate for an increase in internal corrosion risk by taking action to reduce the mechanical damage risk. This means that a higher content of CO_2 or O_2 can be accepted at the cost of reducing risk from another threat. If the intent is to reduce risk to the lowest achievable level, then it is clear that reducing CO_2 or O_2 content aligns with this goal.

E. Existing Rule 30 Gas Quality Requirements are within Common Industry Standards and Achievable through Ordinary Means

The reduction of maximum allowable concentrations of corrosive gas within a reasonably achievable range is therefore a sensible way to increase pipeline safety. The existing allowable maximum concentration of CO_2 is higher than typical gas quality specifications but still within the normal range. A gas quality survey was conducted by SwRI in 2003[1] that included 64 pipeline operators. The median allowable CO_2 fraction was 2% and the range was 1% to 5%. Moreover, Rule 30's carbon dioxide limitation is consistent with a study conducted by the Gas Processing Association, which found that a

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[1] N. Sridhar, F. Song, and M. Nored, 'Guidelines/Quality Standards for Transportation of Gas Containing Mixed Corrosive Constituents, PRCI Report No. L52227, May 2004.

carbon dioxide limit of 3% - 4% is representative of U.S. pipelines.[2] This finding aligns with a sampling of pipeline carbon dioxide limits that are charted below in Table 1.

Table 1 - Snapshot of Pipeline Carbon Dioxide Limits

CO_2 Limit	
Pipeline	**Total**
<u>SoCalGas</u>	<u>3%</u>
Northern Border Pipeline	2%
Riverside Pipeline Co.	1%
Southern Star Central Gas	1%
Crossroads Pipeline Co.	0.1250%
Northern Natural Gas Co.	2%
Kinder Morgan Illinois	2%
South Georgia Natural Gas Co.	3%
Wyoming Intrastate Co.	3%
North Baja Pipeline	3%

These data support the conclusion that the existing (3%) CO_2 specification is higher than normal industry requirements and within the range. This is consistent with the conclusion that CO_2 concentrations less than 3% are reasonably achievable.

SoCalGas recommends retaining its oxygen limit of ≤ 0.2% because in very small quantities, oxygen is corrosive to steel pipelines.[3] This is especially a concern where free water is available, and given the fact that the formation and accumulation of liquid water is extremely difficult to prevent, particularly with the possibility of upsets in dehydration systems.

SoCalGas' oxygen limit is supported by the AGA, which recommends a 0.2% oxygen maximum in its Report No. 4A.[4] Moreover, SoCalGas' oxygen limit is equal to, but not more restrictive, than normal industry requirements, as evidenced in Table 2 below.

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[2] "The Gas Processing Industry: Its Function and Role in Energy Supplies," Gas Processors Association.
[3] Oxygen "can promote pipeline corrosion in the presence of water and sulfur." *See* "Guidebook to gas Interchangeability and Gas Quality", BP and International Gas Union, at Table 3.5.
[4] American Gas Association, Transmission Measurement Committee, AGA Report No. 4A, Natural Gas Contract Measurement and Quality Clauses, Washington, D.C.: American Gas Association, 2001.

Table 2 - Snapshot of Pipeline Oxygen Limits

O_2 Limit	
Pipeline	**Total**
SoCalGas	0.20%
Cheyenne Plains	0.01%
Colorado Interstate Gas Co.	0.01%
QuestarPipeline	0.01%
Panhandle Eastern Pipeline	0.005%
Trunkline Gas Co.	0.005%
Viking Gas Transmission Co.	0.005%
B-R Pipeline Co.	0.20%
Centerpoint Energy	0.20%
Transcolorado Gas Transmission	0.20%

Gas quality requirements are typically set for a variety of commercial considerations, and internal corrosion has become increasingly important. Some of the reasons for this include changes in pipeline safety regulations,[5] an increased emphasis on overall pipeline integrity management, significant internal corrosion failures of pipelines carrying gas specified to be dry (e.g., Carlsbad, NM[6]), and significant pipeline failures in the past year (regardless of failure cause). The increased attention on internal corrosion has increased awareness of its impact on overall pipeline safety and integrity management. It is expected that this awareness will continue to cause pipeline operators to revisit gas quality requirements that were set without full consideration of internal corrosion concerns.

III. QUALIFICATIONS

I am Director of the Det Norske Veritas (U.S.A.) Inc. (DNV) Materials and Corrosion Technology Center in Columbus, Ohio. The Technology Center is an engineering and research organization specializing in the evaluation of materials properties, materials selection, corrosion mechanisms, corrosion control, forensic investigation, asset integrity, and asset life extension. Its staff consists of ~20 Ph.D. researchers in metallurgical science, materials science, and chemical engineering. In addition, DNV in Columbus has over 50 B.S. and M.S. engineers supporting the same activities. The combination of scientists and engineers with practical experience allows delivery of optimized engineering solutions to materials and corrosion related problems.

[5] 49 CFR Part 192.
[6] 'Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico August 19, 2000,' NTSB Report Number: PAR-03-01, adopted on 2/11/2003.

I am President of NACE International, the world's largest corrosion society with more than 26,000 members. I have been involved with NACE for 20 years, with both technical and administrative committee leadership positions; I received the NACE Presidential Achievement Award in 2004 for role in developing a pipeline internal corrosion training program.

I received a Ph.D. in Chemical engineering from the University of Florida in 1993 with dissertation on corrosion of marine screws funded by the United States Office of Naval Research. My career focus has been to apply corrosion science to engineering applications, primarily in the oil and gas production and pipeline industry segments.

I am widely recognized in the pipeline transmission community largely because of my role in developing Internal Corrosion Direct Assessment (ICDA). The method is incorporated in NACE and ASME standards, and is included in US Federal Regulations (49 CFR Part 192).

My experience includes developing, improving, and auditing corrosion management programs for oil and gas pipeline systems. Most of this experience focused on finding opportunities to optimize maintenance activities in aging systems. This experience includes that from previous employment at ARCO Oil and Gas Company.

I have not previously testified before the California Public Utilities Commission.