BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California

R.04-01-025

PREPARED DIRECT TESTIMONY OF

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ON BEHALF OF THE

INDICATED PRODUCERS, WESTERN STATES PETROLEUM ASSOCIATION
AND CALIFORNIA INDEPENDENT PETROLEUM ASSOCIATION

October 5, 2005

MetCorr
I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.
A My name is Bruce D. Craig. I am President of the consulting firm of MetCorr, a metallurgy and corrosion consulting firm. My business address is 4600 South Ulster St, Suite 700, Denver, Colorado 80237. A statement of my qualifications is presented as Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?
A This testimony is presented on behalf of the Indicated Producers. The Indicated Producers is an ad hoc coalition which, for the purposes of this testimony, represents the California producing interests of Aera Energy LLC, Chevron U.S.A. Inc., and Occidental of Elk Hills, Inc. (the “Indicated Producers”), the Western States Petroleum Association and the California Independent Petroleum Association. CIPA is a non-profit trade association dedicated to representing the interests of independent oil and natural gas producers operating in California. The association’s membership currently comprises 400 companies. WSPA is a nonprofit trade association representing 26 companies that explore for, produce, transport, refine and market petroleum and petroleum products in California and five other Western states.
Q WHAT IS THE PURPOSE OF THIS TESTIMONY?

A The purpose of this testimony is to address changes to the current gas quality specifications proposed by Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E) that would reduce the maximum acceptable carbon dioxide (CO$_2$) and oxygen (O$_2$) content of the gas delivered into the utility systems. Specifically, this testimony responds to the August 12, 2005, direct testimony of Larry J. Sasadeuz on behalf of SoCalGas regarding the relationship of CO$_2$ and O$_2$ to corrosion. My testimony emphasizes the importance of evaluating the interaction of water with CO$_2$ and O$_2$ in drawing conclusions regarding potential corrosion and the appropriate specifications for these constituents. My testimony concludes that no sound scientific basis has been presented to support a broad modification of CO$_2$ and O$_2$ specifications as proposed by SoCalGas.

Q HOW DOES SOCALGAS PROPOSE TO MODIFY EXISTING SPECIFICATIONS FOR CO$_2$ AND O$_2$?

A SoCalGas proposes to modify the CO$_2$ and O$_2$ specifications as follows:

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Current</th>
<th>Proposed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon Dioxide</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Oxygen</td>
<td>0.2%</td>
<td>0.1%</td>
</tr>
<tr>
<td>Liquids</td>
<td>Not Specified</td>
<td>No Liquids</td>
</tr>
</tbody>
</table>

Q WHAT ARE YOUR CONCLUSIONS REGARDING SOCALGAS’ PROPOSED CHANGES?

A The need for the proposed changes has not been substantiated. SoCalGas has not demonstrated by way of pipeline failure analyses, in-line inspection results, corrosion
monitoring or any direct assessments that a corrosion problem currently exists or can be anticipated in the future that is the direct result of transporting gas that contains 3% CO₂ and 0.2% O₂.

II. CORROSION OCCURS WHEN CO₂ AND O₂ ARE IN THE PRESENCE OF LIQUID WATER.

Q WHAT CAUSES CORROSION?
A Corrosion is an electrochemical process, which means that in addition to chemical reactions there is also the transfer of electrons in the process. These reactions only take place in the presence of liquid water (aqueous corrosion). When water is in contact with a gaseous phase that contains CO₂ and O₂, these constituents will dissolve into the water phase at a concentration dependent on the water chemistry, the temperature and the pressure in the system.

Q HOW DOES CORROSION OCCUR IN THE PRESENCE OF CO₂?
A For CO₂ dissolving in water the simplified reaction is:

\[
\text{CO}_2 \text{(dissolved)} + \text{H}_2\text{O} \leftrightarrow \text{H}_2\text{CO}_3 \leftrightarrow \text{H}^+ + \text{HCO}_3^- \quad (1)
\]

In essence, when CO₂ is dissolved in water, it produces carbonic acid (HCO₃⁻). The corrosion of steel occurs through the reactions:

\[
2\text{H}^+ + \text{e} \rightarrow \text{H}_2 \quad (2)
\]

\[
\text{Fe} \rightarrow \text{Fe}^{++} + 2\text{e} \quad (3)
\]
When the reactions are added together the complete reaction for the corrosion of steel in water containing dissolved CO₂ is:

\[
\text{CO}_2 + \text{H}_2\text{O} + \text{Fe} \rightarrow \text{FeCO}_3 + \text{H}_2
\]  

(4)

In other words, steel (shown as iron in Eq. 3) dissolves (corrodes) while at the same time hydrogen ions in solution (the acid) combine to form hydrogen gas that bubbles out of solution. Equation 2 is referred to as the reduction reaction and occurs at the cathode while Equation 3 represents the corrosion of steel and is the oxidation reaction which occurs at the anode.

Q HOW DOES CORROSION OCCUR IN THE PRESENCE OF O₂?

A Unlike CO₂ dissolved in water that forms carbonic acid (H₂CO₃), oxygen dissolved in water does not form an acid. The reason dissolved oxygen (DO) causes an increase in corrosion is due to the depolarization of the cathode by reaction with hydrogen ions according to the reaction:

\[
4\text{H}^+ + \text{O}_2 + 4\text{e} \rightarrow 2\text{H}_2\text{O}
\]  

(5)

In other words dissolved oxygen speeds up the dissolution of steel by reacting with the hydrogen ions on the metal surface.
Q  CAN CO$_2$ and O$_2$ ACT IN CONCERT TO PRODUCE CORROSION?

A  Yes. The two gases (CO$_2$ and O$_2$) cause corrosion to occur in the water phase by two different mechanisms but they can act in concert to increase the corrosion rate. However, the resultant corrosion rate is not easily determined since the number of variables is so large. There is no one simple rule that defines the combined effect of CO$_2$ and O$_2$ on the corrosion rate of steel. It is therefore most common to consider the two potential corrodents separately.

Q  IS IT FAIR SIMPLY TO SAY THAT THE PRESENCE OF CO$_2$ and O$_2$ AT PARTICULAR CONCENTRATIONS IS CAUSE FOR CONCERN?

A  No. The most important aspect from a pipeline viewpoint is that corrosion does not occur in the absence of liquid water – regardless of the concentration of CO$_2$ and/or O$_2$. If the gas is dry (above the dew point) entering the pipeline and the temperature of the gas does not decrease to below the dewpoint during pipeline transport, no water will condense from the gas, so there will be no corrosion. Corrosion requires the presence of an electrolyte (water) to proceed. Therefore, if there is no water present in the pipelines it makes no difference if the gas contains 2% or 3% CO$_2$ or 0.1% or 0.2% O$_2$, there will be no corrosion. Further supporting this fact is a report from the Pipeline Research Council International (No. L52227) referenced by SoCalGas as a document they rely upon, that states “In the absence of water, gases such as CO$_2$, H$_2$S and O$_2$ cannot cause corrosion”.

Q  DOES NATURAL GAS DELIVERED BY PIPELINES OR PRODUCERS INTRODUCE FREE WATER INTO A PIPELINE SYSTEM IF GAS DELIVERED INTO THE SYSTEM MEETS CURRENT PIPELINE SPECIFICATIONS FOR WATER?

A  No, it should not for the reasons explained below.
III. ASSUMING GAS QUALITY STANDARDS FOR WATER CONTENT, CO₂ AND O₂ ARE MET, THE CORROSION POTENTIAL ON THE SOCALGAS SYSTEM DOES NOT ARISE FROM THE COMPOSITION OF GAS RECEIVED INTO THE SYSTEM.

Q ASSUMING THAT THE QUALITY PROVISIONS OF SOCALGAS’ RULE NO. 30 APPLY TO GAS RECEIVED INTO ITS SYSTEM FOR TRANSPORTATION TO END-USE CUSTOMERS, IS THE GAS RECEIVED BY SOCALGAS ABOVE THE DEWPOINT, OR “DRY”?

A Yes. SoCalGas’ Rule No. 30 I.2.b. states as follows: “For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20°F at delivery pressure.” The dewpoint is that temperature and pressure at which the gas is saturated with water vapor but at which no liquid water condenses. Thus for a gas stream containing 7 pounds of water / million cubic feet of gas at 800 psig, in accordance with the above, the dewpoint temperature would be +29°F (from McKetta and Wehe). Below +29°F, water would drop out as a liquid. It would be very unusual for the temperature in SoCalGas pipelines to fall below this temperature. Moreover, at a constant water content of 7 lbs water/ million cubic feet of gas as the pressure decreases below 800 psig, the dewpoint temperature decreases even further below +29°F, making water condensation even more unlikely. Therefore, if gas delivered into the SoCalGas system meets the specification stated in Rule No. 30 I.2.b., the gas delivered by producers, interstate pipelines or other interconnecting parties cannot be causing corrosion because it cannot be condensing water in the pipelines.
Q    ASSUMING THAT GAS RECEIVED BY THE UTILITY IS NOT THE CAUSE OF
CORROSION SINCE IT IS DRY GAS, WHAT IS THE CAUSE OF ANY
POTENTIAL CORROSION?

A    Mr. Sasadeusz observes that “the most likely location for corrosion is in the drip
legs and other low spots where water can accumulate. The largest corrosion rate is
likely to occur where the partial pressure of CO₂ is the highest, including storage fields
and high pressure transmission pipelines.” It is unclear why, if gas enters “dry,” that
water is accumulating in these areas. SoCalGas does not in its testimony, as further
discussed below, offer sufficient information regarding how and why water is
accumulating in these areas or whether the utility is taking action to minimize water
accumulation. SoCalGas mentions the “formation and accumulation of liquid
water….particularly with the possibility of upsets in the dehydration system”. No
definitive data or information was provided to support these comments. The term
“formation of water” apparently suggests water condensing from the gas which is not
likely for the reasons mentioned above concerning dewpoint. Periodic upsets of
dehydration systems is a common occurrence in gas treating systems but this does not
automatically translate into a corrosion problem in a pipeline downstream of the
dehydrator. Almost all gas dehydration is performed using glycol (typically some form of
ethylene glycol) which in itself acts as a corrosion inhibitor. Therefore, carry over of
water from the dehydration system will always carry glycol as well which will act as a
corrosion inhibitor for any water that enters the pipeline from this route. Corrosion in
these locations, assuming again that delivering producers meet the utility quality
standards, is not then the result of deliveries of natural gas from these producers.
Q IN LIGHT OF THESE CIRCUMSTANCES, WILL A REDUCTION IN THE CO₂ and O₂ SPECIFICATIONS REDUCE THE LIKELIHOOD OF CORROSION ON THE SOCALGAS SYSTEM?

A No. Reducing CO₂ and O₂ standards as indicated above does not go directly to the problem if water is present. Corrosion risk exists at both 2% and 3% CO₂ and 0.1% and 0.2% O₂ when liquid water is present.

IV. SOCALGAS’ CORROSION ANALYSIS IS INCOMPLETE AND DOES NOT JUSTIFY THE MATERIAL CHANGES PROPOSED.

Q SOCALGAS CONCLUDES THAT “RECENT ANALYSIS AND TESTING HAS CONFIRMED AND RECOMMENDED CHANGES FOR LIMITS ON CARBON DIOXIDE AND OXYGEN…” DO YOU AGREE WITH THIS CONCLUSION?

A No. SoCalGas’ corrosion analysis is incomplete and does not justify the material changes proposed in CO₂ and O₂ specifications. My opinion is based on several grounds, which I explain below.

Q DOES SOCALGAS APPLY CURRENT AND SOUND ANALYTICAL PRINCIPLES TO REACH ITS CONCLUSIONS?

A No. To begin with, SoCalGas’ analysis significantly underplays the importance of liquid water in its analysis. As noted above, first and foremost, there is no corrosion without liquid water present, regardless whether there is 2% CO₂ or 3% CO₂. The same is true for oxygen in the gas. Mr. Sasadeuz’ testimony fails to address the presence of water in the system, noting only that “[t]he most likely location for corrosion is in the drip legs and other low spots where water can accumulate.” The Commission cannot make an informed decision regarding SoCalGas’ proposal without greater information on the presence of liquid water. The Commission must inquire where water is present, why
water is present in those locations and what tools SoCalGas can exercise to mitigate
existing and prevent future water accumulation. These measures are discussed further
below.

Q ARE THERE OTHER AREAS IN SOCALGAS’ TESTIMONY THAT FAIL TO
SUPPORT ITS CONCLUSIONS AND RECOMMENDATIONS?

A Yes. SoCalGas takes an unscientific approach by relying on a “common rule-of-thumb”
correlating partial pressures to corrosion. Mr. Sasadeuz states that “[a] common rule of
thumb is that corrosion rates are usually minimal at partial pressures less than 7 psia and
severe corrosion is expected at greater than 30 psia.” The “rule” was discredited long
ago by the corrosion community because it does not account for the many other variables
that contribute to CO₂ corrosion. While CO₂ partial pressure is one important factor in
the corrosion of carbon steels, other factors such as temperature and velocity have a
significant effect as well. Moreover, factors such as iron content of the water, water pH,
the presence of corrosion products, condensation of hydrocarbons and the presence of
glycol can all reduce the corrosion rates that are determined if only the partial pressure of
CO₂ is considered. The “rule of thumb” thus is not a reliable basis upon which to
determine corrosion potential on the SoCalGas system without a much more detailed
analysis.
Q ARE THERE OTHER ELEMENTS OF SOCALGAS' ANALYSIS THAT FAIL TO SUPPORT ITS CONCLUSION?

A Yes. SoCalGas concludes that because it has “little or no data to describe the drip fluid composition”, “it is difficult to estimate the change in corrosion rate that will result from changing the CO2 specification limit.” State-of-the-art modeling makes this estimation quite easy. The state-of-the-art for modeling CO2 corrosion of steel pipelines is now quite advanced and has culminated in at least 6 separate computer models worldwide that deal with this specific type of corrosion. Several of the models are proprietary within certain companies while others are available for purchase by the public and one is available free on the Internet (NORSOK). The majority of these models are based on more than 25 years of work on CO2 corrosion by C. DeWaard and colleagues at Shell. Their work was published in the open literature and forms the basis of most of the pipeline industry's prediction of corrosion rates for new and existing systems. The model MetCorr uses is the most advanced from DeWaard and Smith (the Electronic Corrosion Engineer, ECE). DeWaard retired several years ago from Shell but continues to improve the model he developed at Shell. MetCorr has been a frequent contributor to the development of this model through its various versions and upgrades.

Q WHAT ADDITIONAL DATA WOULD BE REQUIRED TO PERFORM THE MODELING EFFORTS YOU HAVE IDENTIFIED?

A The additional data that are required depends totally on how detailed and accurate a modeling effort is required or desired. As SoCalGas has shown using a simple rule-of-thumb can give results but they are suspect. For a complete analysis using one of the better CO2 corrosion models the SoCalGas system would need to be divided into parts that are more easily modeled as separate entities. For example, the conditions for gas
withdrawal from gas storage sites will be different than for transmission pipelines. Once these entities are established the typical data that are required are:

1. Gas composition (ie. CO₂ and H₂S content)
2. Pipeline inlet and outlet, pressure and temperature
3. Pipe outside diameter and wall thickness
4. Chemistry of the steel pipe
5. Length of pipeline or segment under study
6. Gas flow rates
7. Water in the pipeline condensing from the gas phase will be fresh water and is so modeled but if there is water entering the system from another source then the water composition is important.
8. If glycol is intentionally added and how much
9. If corrosion inhibitors are intentionally added and their efficiency or availability
10. If hydrocarbons are expected to condense, the API gravity of the condensate.

All of these inputs have an effect on the corrosion rate from CO₂ and must be considered in order to properly establish the corrosion rate expected in any part of the system.

Q WITHOUT UNDERTAKING THIS MODELING EFFORT, CAN THE COMMISSION DRAW ANY SOUND CONCLUSIONS REGARDING THE BENEFITS OF TIGHTENING STANDARDS FOR CO₂ AND O₂?

A No. Until these calculations are performed using a reliable CO₂ corrosion model, the Commission cannot be confident that there will be any demonstrable reduction in corrosion with a reduction in CO₂.
Q  CAN YOU PROVIDE AN ILLUSTRATIVE EXAMPLE SUPPORTING YOUR CONCLUSION?

A  Yes, two examples can be used to demonstrate the significance of reducing the CO2 content from 3% to 2%.

The first example is a transmission line, 24 inches in OD and 10 miles long. Assuming some typical values (60°F, 500 psig, 100 MMCF/D), if the water content of the gas is 7 pounds/MMCF/D (typical pipeline specification), using the ECE model the corrosion rate is zero for both 2% and 3% CO2 because there is no free water present. If everything is kept constant but the water content is increased to 20 pounds/MMCF/D the corrosion rate for a gas containing 2% CO2 is 0.6 mils/year (0.0006 inches/year) and for 3% CO2 the rate is 0.8 mils/year (0.0008 inches/year). These are extremely low corrosion rates regardless whether the gas contains 2% or 3% CO2 and are essentially the same corrosion rate. Most pipelines have a built in corrosion allowance of 0.125 inch (125 mils) which at the worst rate (0.8 mpy) would take 156 years to compromise. Even then the wall of the pipe would not be penetrated, only the corrosion allowance would be gone and the pipeline would still have full integrity. These corrosion rates also assume the pipe is always continuously wet with liquid water for an entire year, which is highly unlikely unless there is no control of liquid water in the pipeline (i.e., large quantities of water are allowed to enter the pipeline and there is no pigging program). If the pipeline is intermittently wet, which is more likely, the corrosion rate will be a fraction of the very low rates above.

Another example, for which the ECE is not well suited would be the corrosion in a static drip leg. Using the same operating conditions as above but using the NORSOK model the corrosion rate in a drip leg full of water would be 25 mils/year for 2% CO2 and 32 mils/year for 3% CO2, not a significant difference in corrosion rate. Both of these rates are sufficiently high that the application of a corrosion inhibitor is required to ensure failure does not occur even for the 2% case. So it is unjustified to suggest that at 2% CO2 there will be no significant corrosion problem but at 3% CO2 there will be, when the difference is only 7 mils/year.

Both of these examples demonstrate that using a proper CO2 corrosion model and taking into account the operating conditions as well as velocity, water composition, temperature, etc an accurate prediction of the corrosion rate can be made and a reasonable comparison made between 2% CO2 and 3% CO2 and its significance on corrosion. These examples suggest that there is probably little if any significant reduction in corrosion rate by reducing the CO2 content of the gas from 3% to 2%.
Q  DOES YOUR CONCLUSION HOLD TRUE FOR OXYGEN, AS WELL AS CO₂?

A  No. Contrary to CO₂ corrosion, which is modeled based on the mole % CO₂ in the gas phase, oxygen corrosion is evaluated based on its concentration in the water phase - thus it is referred to as dissolved oxygen (DO). There are currently no recognized models for predicting corrosion from DO and while there is a contribution of DO to corrosion in systems containing CO₂ it is difficult to quantify this role. A few of the CO₂ corrosion models include an input for oxygen but this feature has not been scrutinized and validated, as have the CO₂ corrosion models, by experts in the field. However, the corrosion rate of steel from DO alone can be estimated based on the amount of oxygen that dissolves into the water phase. SoCalGas calculated the DO content of water to be 900 parts/billion (ppb) when the gas phase contains 0.1% (1000 ppm) O₂ and indicated that this could produce pitting rates of greater than 15 mils/year and as high as 80 mils/year depending on the amount of CO₂ present. SoCalGas did not present any data or calculations to support these claims. Moreover, Mr. Sasadeusz states “one reference reported that the difference in corrosion rate in stagnant water containing 7 ppm oxygen and 7 ppb oxygen is a factor of about 25 or more.” When the actual reference to which Mr. Sasadeusz refers was provided and reviewed it was found that the actual corrosion rate at 7 ppm oxygen was only 10 mpy, hardly as severe as his statement would imply.

MetCorr calculated the DO content for fresh water with both 1000 ppm and 2000 ppm O₂ in the gas phase using the work of Cramer (S. Cramer, “Oxygen Solubility in Brines”, I&EC Process Design and Develop, p. 618, 1984) to determine the Henry’s Law constant and thence the DO contents. Fresh water was used for this calculation since water condensing from a gas phase will be fresh and not contain brine. For 1000 ppm O₂ in the
gas phase the DO content in the water is 1.73 ppm and for the 2000 ppm O₂, it is 3.47 ppm. Figure 1 (Betz Labs) below shows that at 48°F (closest of the curves to pipeline temperature) the difference in corrosion rate between 1000 ppm and 2000 ppm O₂ is insignificant. For the former the corrosion rate is about 10 to 15 mpy and for the latter about 20 mpy. Therefore, SoCalGas’ approximation of 15 mpy is a good one for both 1000 ppm and 2000 ppm O₂ but there is no significant reduction in corrosion rate at the lower concentration. It should be noted that the 10 to 20 mpy corrosion rate from O₂ is approximately the same as that for the corrosion rate of the drip legs from CO₂ in the example above. Therefore, corrosion from O₂ is expected to be about the same as from CO₂. However, the rates are not simply additive.

![Figure 1- Corrosion Rate of Steel as a Function of Temperature and DO Content](image)

**Q** GIVEN THESE CIRCUMSTANCES, CAN THE COMMISSION DRAW ANY REASONABLE CONCLUSIONS REGARDING THE IMPACT OF REDUCE OXYGEN SPECIFICATIONS?
A No. It would appear from the limited information in the literature that there is no benefit in reducing the oxygen specification.

Q ARE THERE OTHER REASONS WHY THE COMMISSION CANNOT RELY ON SOCALGAS’ ANALYSIS AND CONCLUSIONS?

A Yes. SoCalGas’ analysis appears to overstate the risks associated with existing quality standards by misplacing its reliance on a report sponsored by the Pipeline Research Council International (PRCI).

SoCalGas quotes the PRCI report (which has not yet been made available by SoCalGas to the Indicated Producers), stating that “pitting at the liquid vapor interface in a test solution at 500 psig `...also was a major problem when only 100 ppm (vol) oxygen was present (63mpy).’” The testimony further states that “‘...the results show that 100 ppm (vol.) oxygen is too much for wet gas pipelines.’” Information in the technical literature indicates that oxygen concentrations of less than 10 ppm (vol.) may be acceptable.”.

Finally, SoCalGas notes that “‘The bottom line of these findings is that oxygen contamination of pipeline gas must be avoided at all costs.’”

It is recognized that in general the corrosion rate of steel decreases with decreasing DO, as indicated by Mr. Sasadeusz. His reference to a proprietary PRCI report (published in part as a paper in the open literature, N. Sridhar et. al., Corrosion, Vol. 57, p221, 2001), however, is out of context. His discussion of the report does not disclose that there was H2S present in many of the tests at a partial pressure of 0.5 psia which is equivalent to 1000 ppm H2S under the test conditions (500 psi), far in excess of the 4 ppm maximum allowed in pipeline specifications. This high H2S concentration, coupled with DO, will certainly produced a serious pitting and corrosion problem as the Report concludes.
These conditions, however, are not representative of typical pipeline conditions and should not be used to determine the effect of DO in a gas containing CO₂.

Mr. Sasadeuz also overstates the corrosion rate from the PRCI Report to make his point. The corrosion rate from the Report that Mr. Sasadeusz mentions (63 mpy) is the highest reported in the paper that was published on this work. In fact, the majority of the corrosion rates were in the range of 1.5 to 20 mpy, far less corrosive than suggested by Mr. Sasadeusz.

Indeed, as Mr. Sasadeusz states, 10-20 ppb DO is considered the limit below which corrosion from DO is essentially nil. Importantly, above that level, corrosion increases with increasing DO concentration as shown in the figure above BUT only when water is present.

IV. EVEN ASSUMING A CORROSION ISSUE EXISTS IN ITS SYSTEM, SOCALGAS’ TESTIMONY FAILS TO ADDRESS MITIGATION OF WATER ACCUMULATION AND OTHER SOLUTIONS.

Q YOUR TESTIMONY CONCLUDES THAT SOCALGAS’ ANALYSIS DOES NOT SUPPORT THE CONCLUSION THAT CURRENT QUALITY STANDARDS PRESENT AN UNACCEPTABLE RISK OF CORROSION. ASSUMING THAT THIS CONCLUSION COULD BE SUPPORTED, IS A RESTRICTION OF THE CO₂ AND O₂ SPECIFICATIONS THE ONLY MEANS OF MITIGATING ANY PERCEIVED RISK?

A No. While presumably SoCalGas employs a variety of tools to mitigate these risks, their use, effectiveness or enhancement are not addressed in Mr. Sasadeuz’s testimony.

Q WOULD A LEAK DETECTION PROGRAM, IF CURRENTLY MAINTAINED OR IMPLEMENTED, MINIMIZE CORROSION RISKS?
A Yes, it would. Early detection of leaks can minimize the damage done by corrosion and the extent of repairs that might be required as well as indicate if current corrosion control programs such as pigging and inhibition are not effective. Again, however, Mr. Sasadeuz’s testimony does not illuminate SoCalGas’ current or planned leak detection programs. There are numerous methods available for leak detection and used by pipeline operators to detect leaks from various causes (i.e., corrosion, third party damage, etc). A leak detection program combined with an effective internal corrosion direct assessment program and pigging plan are far more likely to reduce the risk of internal corrosion failures than is simply reducing the amount of CO₂ and O₂ in the gas stream.

Q WOULD PHASE BEHAVIOR AND CORROSION MODELING LIKewise PROVIDE A BENEFICIAL TOOL TO MITIGATE CORROSION RISK?

A Yes. Phase behavior in the case of gas pipelines is the state of phase of all components along the entire length of a pipeline. If only dry gas enters the pipeline and no liquids condense, so only gas exits the pipeline, this is referred to as single phase flow. However, if water and/or hydrocarbons condense in the pipeline, or are otherwise carried into the pipeline with the gas, this is referred to as two phase flow if there is gas + water or gas + condensate, or three phase flow if there is gas + water + condensate. Two and three phase flow are also referred to as multiphase flow. Furthermore depending on the amounts of these liquids, the velocity of the gas and velocity of the condensed liquids and other factors, the flow will have different patterns. Figure 2 shows the most common patterns or flow regimes in horizontal pipelines in multiphase flow.
Figure 2 – Multiphase Flow in Gas Pipelines. The Top Case is for Stratified Flow, the Middle Case is Slug Flow and the Bottom Case is Annular Mist Flow.

At low velocities the flow will be stratified (also referred to as laminar) where the water is on the bottom of the line, the condensate flows on top of the water and the gas rides across the top of the liquids. At higher velocities the liquids periodically move through the pipeline as a slug and at the highest velocities a mist of liquid is carried with the gas that wets the surfaces of the pipe. These flow regimes are also dependent on the inclination of the pipeline. Thus hills and valleys will often change the flow regime from one to another. The flow regime has a significant impact on the corrosion rate from CO₂, the accumulation of water in specific locations, the requirements for corrosion inhibition and the requirements for pigging.

Phase behavior modeling using software programs such as OLGA (some others are PIPESIM and PIPEPHASE) can identify locations in a pipeline that are vulnerable to water drop out and collection as well as the flow regime. The rate of corrosion is not only
dependent on the presence of CO\textsubscript{2} and O\textsubscript{2} but also the amount of water present and the 
flow regime. OLGA is a software simulator for transient multiphase flow of oil 
(condensate), water and gas in pipelines that is widely used in the industry. The acronym 
stands for Oil and Gas and the program was developed and is maintained by Scandpower 
Petroleum Technology in Norway. Once the areas where water will accumulate are 
identified along with the flow regime, any of the CO\textsubscript{2} corrosion models described above 
can be used to determine the expected corrosion rates. In fact, OLGA includes earlier 
versions of the DeWaard work and the NORSOK model discussed above in my 
testimony so this represents a complete package. This approach to pipeline integrity has 
been called internal corrosion direct assessment (ICDA) and is expected to be one of the 
important tools for complying with OPS Pipeline Integrity Management Programs 
required for interstate pipelines. ICDA may be used in lieu of in-line inspection (ILI) or 
combined with it for a powerful means to predict and confirm the extent of corrosion 
occurring in pipelines. Again, SoCalGas’ use of these tools is not discussed in Mr. 
Sasadeuz’s testimony.

**Q WOULD A WELL-DESIGNED “PIGGING” PROGRAM MITIGATE CORROSION RISK?**

**A Yes. “Pigging” is a term used by the pipeline industry to describe the application of a 
solid device that is pushed through the pipeline with water or gas in order to accomplish a 
specific task. Scrapper pigs and ball pigs are used to clean the inside of pipelines and 
remove liquid water that may contribute to corrosion. Ball or foam pigs are used to 
spread inhibitors on the pipe wall for corrosion protection. Instrumented pigs (also**
referred to as smart or intelligent pigs) are used to examine the pipeline for imperfections and defects.

Since the real issue at hand is not whether 2% or 3% CO₂ is corrosive but rather whether water is present and if so where it is, a viable pigging program is always needed to keep the system clean of standing water where corrosion can proceed. Frequent pigging to remove liquid water is the most effective method to minimize corrosion in pipelines. Furthermore, a good pigging program allows the capture of water samples that can be analyzed for the presence of residual corrosion inhibitor that would demonstrate the effectiveness of the inhibition program and collection of corrosion products that can be analyzed to determine what contaminants are causing corrosion. Again, however, SoCalGas has not indicated that it employs a comprehensive pigging plan and whether that plan has been optimized for all its operations. Moreover, periodic in-line inspection (ILI) using “intelligent” pigs is recognized by the pipeline industry as one of the best methods to confirm the integrity of existing pipelines and the location of corrosion problems that must be further evaluated. The use of ILI has become an important part of most interstate pipeline company programs that seek to comply with DOT pipeline integrity programs. If SoCalGas desires to ensure complete pipeline integrity then they must have a plan that requires periodic ICDA of each pipeline coupled with leak detection and ILI and not simply rely on gas composition to reduce the risk of internal corrosion.
V. THE COMMISSION CANNOT REASONABLY ADOPT SOCALGAS’ PROPOSAL WITHOUT FURTHER INVESTIGATION AND ANALYSIS.

Q DO YOU BELIEVE THAT SOCALGAS’ POSITION IS SUFFICIENTLY SUPPORTED TO WARRANT THE COMMISSION’S ADOPTION?

A Absolutely not. SoCalGas is proposing to change specifications that have been in place for many years; Rule 30 was formally implemented in 1988. Moreover, these specifications fall reasonably within a mid-range of pipelines according to SoCalGas’ survey presented in the Commission’s February 2005 workshop. It would be imprudent to make the proposed changes without adequately:

- Exploring why liquid water is present in the SoCalGas system and
- Demonstrating that (1) corrosion is, indeed, a problem on the SoCalGas system; (2) reduction of the CO₂ and O₂ specifications would reduce the risk of corrosion and (3) there are no other tools or alternatives available to the utility to mitigate the risk of corrosion.

To modify the CO₂ and O₂ specifications without fully exploring the nature and extent of risk and other means of risk mitigation would be imprudent.

Q WHAT ADDITIONAL INVESTIGATION WOULD BE REQUIRED TO EXAMINE SOCALGAS’ PROPOSAL?

A First, it would be well to understand the source of water in the SoCalGas system. For example, is there something inherent in the storage operations or reservoirs that results in a higher water content for storage withdrawals? Likewise, does the production of Native Gas by SoCalGas in its storage reservoirs contribute in any way to the higher water content? These and other related questions should be explored before modifying CO₂ and O₂ specifications.
Q  ARE THERE OTHER INQUIRIES THAT THE COMMISSION SHOULD MAKE IF SOCALGAS CONTINUES TO PURSUE MODIFICATION OF THESE SPECIFICATIONS?

A  Yes, there are a series of technical investigations that the Commission should make.

- **Review of leak data.** Review of historical leak data coupled with failure analyses would provide an understanding of what the primary causes for leaks are, which may be third party and external corrosion issues rather than internal corrosion. Until such a review has been performed it is unreasonable to assume that internal corrosion is a significant problem and one that must be countered by reducing the CO₂ and O₂ content of the gas.

- **Analysis of pipeline leaks.** It is common practice among most pipeline companies and gas producers to perform failure analyses once a leak or rupture has occurred. These analyses can be as simple as visual observations by field people cutting out or repairing a leak to the more complete metallurgical analyses in a laboratory. If CO₂ and O₂ are causing corrosion problems in pipelines the source of corrosion can be identified through analysis of the corrosion products. Moreover, not all internal corrosion can simply be assumed to be caused by CO₂ and/or O₂ in the gas. There are numerous cases of internal corrosion in pipelines caused by bacteria, which are referred to as microbiologically induced corrosion (MIC). MIC also requires liquid water to be present for corrosion to proceed, however, the bacteria do not enter the pipeline from the gas but most often as the result of contaminated hydrotest water which is the responsibility of the gas transmission company. In their response to a data request, SoCalGas indicated in an interoffice memo dated December 4, 2000 that 5 out of 7 corrosion leaks and internal corrosion problems at different locations in their system may be caused by MIC. Reducing the CO₂ and O₂ content of the gas will have no effect on reducing leaks from MIC.

There are also many leaks in older gas pipelines along the long seam weld as a result of poor quality welding during pipe manufacturing. Again these are not typically corrosion related and cannot be assumed to be the result of corrosion. Depending on the age of the pipelines, the weld quality may be poor and thus failure of the weld seam may be a higher risk for leaks than a corrosion failure.

- **Review and optimize pigging and chemical inhibition program.** Since it has been shown above that regardless whether the gas contains 2% CO₂ or 3% CO₂ there will be corrosion whenever water is present, SoCalGas should currently have in place a comprehensive pigging and chemical inhibition program. Effective pigging and inhibition programs will essentially eliminate internal corrosion but removing standing water from the pipelines and when pigging is not performed by chemical inhibition of water that accumulates in the pipelines. If in fact 3% CO₂ is substantially more corrosive than 2% CO₂, a review of the SoCalGas pigging and

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inhibition program would demonstrate this fact (i.e. higher concentrations of
inhibitor, more frequent applications of inhibitor and more frequent pigging.)

Model the potential impact of changes in standards on corrosion. As has been
discussed earlier in this testimony, there are several complete CO₂ corrosion models
available to SoCalGas that can be used to model the potential impact of changing the
standards on the expected corrosion in their pipelines rather than simply assuming
that the corrosion rate will decrease significantly. SoCalGas has not demonstrated by
any acceptable methods that changing the standards will actually decrease the
corrosion rate.

Q  DOES THIS CONCLUDE YOUR TESTIMONY?

A  Yes.
APPENDIX A

METCORR

BRUCE D. CRAIG

EDUCATION

1970 – B.S. Metallurgical Engineering, Colorado School of Mines
1975 – M.S. Metallurgical Engineering, Colorado School of Mines
1980 – Ph.D. Metallurgical Engineering, Colorado School of Mines

PROFESSIONAL EXPERIENCE

1997 – Present President, MetCorr – Established own company to continue consulting in corrosion and materials selection in the same areas of previous experience. Consultant to Mobil Oil and ExxonMobil for Mobile Bay field developments including all high pressure flowlines. Consultant to Duke Energy Field Services on pipeline construction and corrosion, including failure analysis of their existing systems. Consultant to Rocky Mountain Pipeline System on direct assessment of internal corrosion of pipelines. Consulted on materials and construction of the Gaviota Terminal for Texaco and the Pacific pipeline for Anschutz Corp.

Contributed to the latest most comprehensive software model for CO2 corrosion prediction of steel pipelines developed by DeWaard (the basis of almost all worldwide models for CO2 corrosion). Currently use this model for predicting corrosion in pipelines for ExxonMobil USA, BHP Billiton in the Gulf of Mexico, Amerada Hess in West Africa, Unocal in Indonesia and many others worldwide.

1983 – 1997 Senior Consultant, Metallurgical Consultants, Inc. – Involved with writing line pipe specifications for many companies for gas gathering and transport.
Frequently performed failure analysis on pipelines and other equipment. Principal Investigator for industry contract research, especially on stress corrosion cracking and sulfide stress cracking of steels and corrosion resistant alloys.

1973 - 1983 Research Engineer, Marathon Oil Company, Denver Research Center – Consulted to field operations (Drilling, Production and Pipeline) on corrosion problems and metallurgy. Responsible for corrosion inhibitor selection, corrosion monitoring and selection of coatings.

Member of the team involved with the planning and construction of the LOOP (Louisiana Offshore Oil Port) and all associated pipelines, the Marathon Brae field in the North Sea and subsea pipeline construction and corrosion control. Construction and corrosion control of many other pipelines for Marathon Pipeline Co.


1970 – 1972 Officer, United States Army, Corp of Engineers. Viet Nam Veteran.

PROFESSIONAL ASSOCIATIONS AND ACTIVITIES

Registered Professional Engineer, Colorado and Texas
Member, ASM International
Member, National Association of Corrosion Engineers (NACE International)
Member, Society of Petroleum Engineers (SPE)
Member, ASM, National Committee, Academy for Metals, 1983
Member, ASM, National Committee, International Materials Reviews, 1985 –1988
Chairman, Rocky Mountain Chapter ASM International, 1987 – 1988

Honors
Fellow, NACE International
Presented several Keynote Lectures, Invited Talks and Plenary Lectures
University and Industry Short Course Instruction

Adjunct Professor, Colorado School of Mines, Dept of Petroleum Engineering, 1987 – Present

Frequently instruct industry short courses on corrosion and metallurgy.

Books – Author, Contributing Author, Editor

SOME OF MORE THAN 80 PUBLICATIONS


20 “Corrosion Product Analysis- A Road Map to Corrosion in Oil and Gas Production”, *Mat Perform*, p. 56, Aug (2002)


23 B. Friedman and B.D. Craig, Understanding the Basics of Corrosion in Sweet and Sour Gas Treating Plants, Laurence Reid Gas Conditioning Conf, OK City, OK, (2005)