Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon storage facility and the release of natural gas, and Order to Show Cause Why Southern California Gas Company Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility. (U904G).

I.19-06-016
(Filed June 27, 2019)

# CHAPTER II

# PREPARED REPLY TESTIMONY OF ROBERT A. CARNAHAN, P.E. ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)

March 20, 2020

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## CHAPTER II

The purpose of my prepared reply testimony on behalf of Southern California Gas Company (SoCalGas) is to respond to the testimony of Margaret Felts on behalf of the Safety and Enforcement Division (SED)[1] and Mina Botros, Alan Bach, Matthew Taul, Pui-Wa Li, and Tyler Holzschuh on behalf of the Public Advocates Office (PAO) of the California Public Utilities Commission (CPUC). Specifically, SED alleges violations of Section 451 of the California Public Utilities Code because SoCalGas should have used the Vertilog technology to check the casing on 13 wells (Violations 61-73),[2] should have used cathodic protection to prevent the corrosion that led to the SS-25 leak (Violation 86), and because not having a continuous pressure monitoring system for well surveillance prevented the immediate identification of the SS-25 leak and accurate estimation of gas flow rate (Violation 87).[3] Public Advocates Office (PAO) alleges further that corrosion on the SS-25 well would have been timely identified if SoCalGas had assessed those 13 wells, including SS-25,[4] and that cathodic protection could have mitigated corrosion on SS-25.[5] These arguments ignore that the Vertilog technology was not reliable, that PAO's simple corrosion rate calculation is unreliable and speculative, that pressure tests are not intended to detect corrosion, that cathodic protection would not have protected the production casing on SS-25, and that continuous pressure monitoring could not have prevented "catastrophic failure" of SS-25. Moreover, Ms. Felts' contention that the leak existed prior to October 23, 2015 is unsupported.

### I. VERTILOG TECHNOLOGY CIRCA 1988 HAD LIMITED ACCURACY AND WAS NOT A RELIABLE OR DETERMINATIVE INDICATOR OF CASING INTEGRITY.

PAO alleges that "SoCalGas management failed to deal with integrity management issues

[1] SED's Opening Testimony was served on parties to I.19-06-016 on November 22, 2019 without an identified witness, and remains so. Pursuant to SoCalGas Data Request 2 to SED, SED identified Margaret Felts as the sponsoring witness for the entirety of SED's Opening Testimony.
[2] SED Opening Testimony at 10-12.
[3] SED Opening Testimony at 47-50.
[4] PAO Opening Testimony at 3-10.
[5] PAO Opening Testimony at 13.

by taking prudent action in response to" Vertilog testing conducted at Aliso Canyon circa 1988.[6] PAO states further that, following the Vertilog inspection results, "SoCalGas' management failed to undertake a timely inspection" of other wells, including SS-25, and "consequently failed to identify and address corrosion issues."[7]

These allegations presuppose that the Vertilog technology at that time was reliable and accurate. That is not the case.

A. Background Regarding Vertilog Technology.

Vertilog was introduced in the 1970s as a mechanism that attempts to utilize Magnetic Flux Leakage (MFL) to detect casing metal loss.[8] MFL tools measure magnetic leakage fields. The measured field strength and field extension depend on depth and extension of metal loss, metal loss feature shape, wall thickness, magnetization magnetic properties, and logging speed. Historically, however, the results of the first generation of MFL tools were not very satisfactory.[9]

Vertilog works by using a direct current (DC) electric coil to induce a magnetic field that saturates the casing. Where the casing body has no discontinuities, the magnetic field is uniform. Where discontinuities exist, the magnetic field is disturbed and magnetic flux leaks out of the casing wall.[10] The magnitude of magnetic flux leakage is proportional to the amount of metal loss in the casing. Sensors on the Vertilog tool are intended to detect the level of magnetic flux leakage, which is displayed as a voltage signal on the Vertilog chart recording.

Figure 1 below is an example of a standard strip chart used to display Vertilog raw data. It is similar in format to the strip charts associated with the circa 1988 Vertilog-inspected wells.[11] Flux leakage average response is shown on the left-hand track and can be used to evaluate the circumferential extent of a discontinuity.[12] A casing collar will produce an average signal equal

[6] PAO Opening Testimony at 1.
[7] PAO Prepared Testimony at 5.
[8] Ex. II-1 (Haire, J.N. and Heflin, J.D, Dresser Atlas, "Vertilog – A Down-Hole Casing Inspection Service," SPE 6513, 1977).
[9] Ex. II-2 (Goedecke, H., GE Oil & Gas"Ultrasonic or MFL Inspection, Which Technology is Better for You?," Pipeline & Gas Journal, October 2003).
[10] Ex. II-3 (Adams, G.W. and Moffat, W.D., Atlas Wireline Services, "Full-Signature Multiple Channel Vertilog," SPE 22101, 1991).
[11] Ex. II-3 (SPE 22101).
[12] Ex. II-1 (SPE 6513).

to 360 degrees in circumference. Eddy current response is displayed on the first five divisions of the right-hand track, which is zero at the fifth division and increases to the left. The remaining 15 divisions of the right-hand track display maximum flux leakage response, which is zero at the fifth division and increases to the right.

To *estimate* the penetration depth of a discontinuity, maximum flux leakage was read from the strip chart, eddy current response was used to determine whether the discontinuity was internal or external, the discontinuity was identified as an isolated pit or general corrosion, and depth was determined from a separate calibration chart for the size, weight, and grade of casing.[13] Wall thickness loss classifications defined in Vertilog reports are as follows: Class 1: 0-20%, Class 2: 21-40%, Class 3: 41-60%, and Class 4: 61-80%.

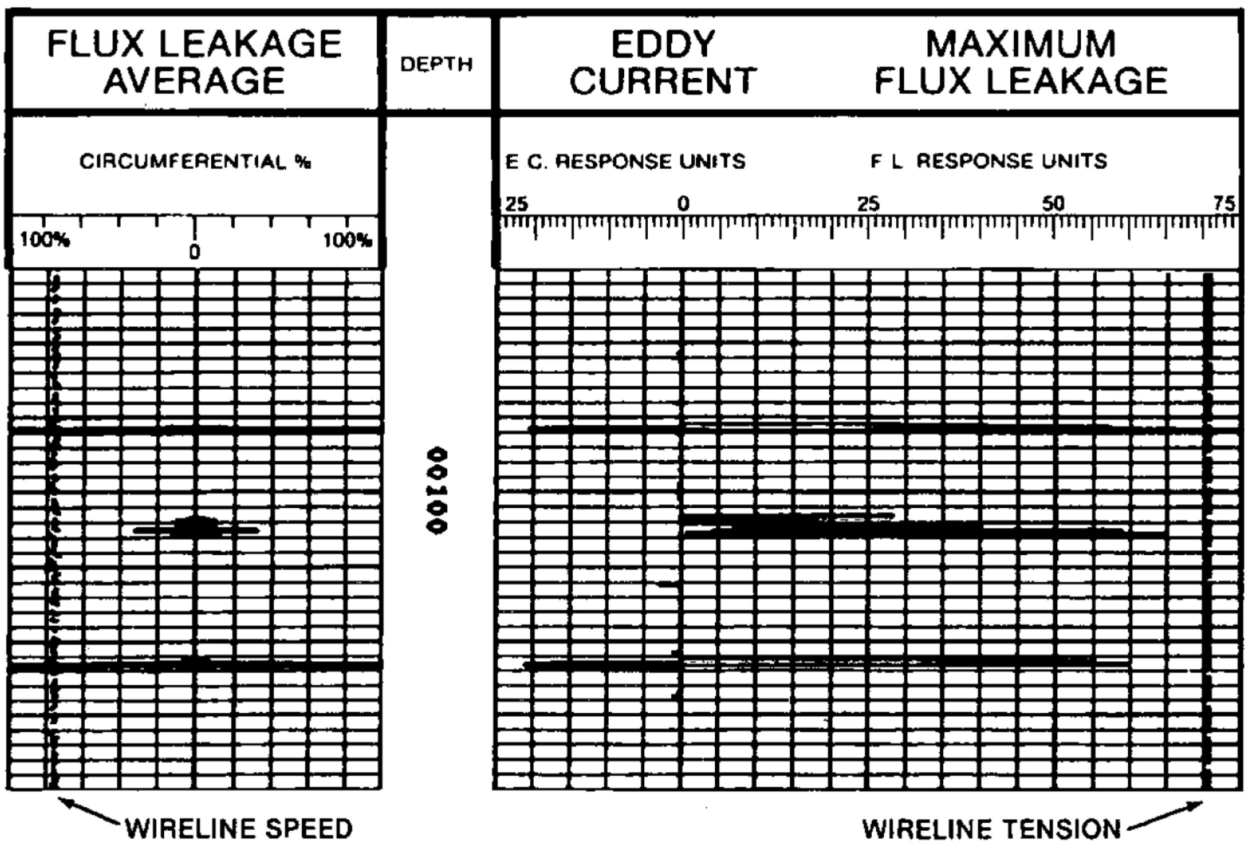


Figure 1. Standard Vertilog strip chart circa 1991 (from SPE 22101).

B. <u>The Circa 1988 Vertilog Technology Had Limitations.</u>

While useful to a certain extent, the Vertilog technology circa 1988 suffered from certain

[13] Ex. II-3 (SPE 22101).

substantial deficiencies.

For example, the Vertilog technology did not provide a method for differentiating isolated pitting from general corrosion. Metal loss depth cannot be accurately determined without first classifying metal loss as isolated pitting or general corrosion. The below Vertilog interpretation charts for well P-32C (Figure 2) illustrate this principle. These charts display metal loss depth class as a function of maximum flux leakage for 8 ⅝-in 36 pound/foot K55 or N80 casing. The upper chart, used where the production casing is not enclosed within a surface casing, shows that flux leakage between 16 and 30 could be either Class 2 external general corrosion or Class 3 external isolated pitting. If metal loss were present where the casing was located within the surface casing (lower chart), flux leakage in the range 22 to 30 could be either Class 2 external general corrosion or Class 4 external isolated pitting.

VERTILOG INTERPRETATION CHARTS
RESPONSE VS % METAL LOSS

CASING SIZE-8-5/8" WEIGHT- 36# GRADE-K-55 N-80

CHART-86J55E
OUTSIDE 13-3/8" SURFACE PIPE

| | 21%-40% CL-2 | 41%-60% CL-3 | 61%-80% CL-4 | 81%-100 CL-4PP |
|---|---|---|---|---|
| ODIP | 4-14 | 16-34 | 36-70 | 72+ |
| IDIP | 10-18 | 20-34 | 36-56 | 58+ |
| ODGC | 8-30 | 32-70 | 72-120 | - |
| IDGC | 18-36 | 38-68 | 70-112 | 114+ |

MAXIMUM FL RESPONSE IN VERTILOG UNITS

SURFACE PIPE

CASING SIZE-8-58" WEIGHT-36# GRADE-K-55 N-80

CHART-86J71E
INSIDE 13-3/8" SURFACE PIPE

| | 21%-40% CL-2 | 41%-60% CL-3 | 61%-80% CL-4 | 81%-100 CL-4PP |
|---|---|---|---|---|
| ODIP | 2-4 | 6-20 | 22-58 | 60+ |
| IDIP | 6-12 | 14-26 | 28-48 | 50+ |
| ODGC | 8-30 | 32-70 | 72-120 | - |
| IDGC | 18-36 | 38-68 | 70-112 | 114- |

MAXIMUM FL RESPONSE IN VERTILOG UNITS

Figure 2. Vertilog interpretation chart provided with log for well P-32C.[14]

Another problem with Vertilog is that there are multiple permutations associated with the analysis of metal loss at any given depth, resulting in inherent uncertainty when interpreting the results. For example, the Vertilog data relating to well FF-35B identifies some features as either internal **or** external, and others as isolated pitting **or** general corrosion. Two relevant Vertilog interpretation charts for FF-35B are shown here: (a) 86J55E, the chart shown in the upper portion of Figure 2, and (b) 86P1E (Figure 3), which report different metal loss depths for the same Vertilog signal. Depending on whether the metal loss at 6867 feet is classified as general

[14] Ex. II-4 (SCG00238148).

corrosion or isolated pitting, and depending on which interpretation chart is used, the reported depth can nearly double. In other words, there are **four permutations** for a single depth data point. The feature at 6867 feet is identified as either: (1) isolated pitting of 44% depth (86J55E), (2) isolated pitting of 37% depth (86P1E), (3) general corrosion of 32% depth (86J55E), or (4) general corrosion of 25% depth (86P1E).

VERTILOG INTERPRETATION

COMPANY: SOUTHERN CALIFORNIA GAS COMPANY
WELL: I.W. 82
FIELD: ALISO CANYON 11·11·89
CNTY: LOS ANGELES
STATE: CALIFORNIA

wall loss

| DEPTH | VERTILOG UNIT | LOCATION & EXTENT | CHART NO. 86J55E | CHART NO. 86P1E | PERCENT AVE |
|---|---|---|---|---|---|
| 74 | 20 | ID or OD, IP | 60 or 52 | | 60 or 52 |
| 2148 | 15 | ID, IP | 34 | | 34 |
| 2166 | 14 | OD, IP | 39 | | 39 |
| 2251 | 21 | OD, IP | 48 | | 48 |
| 3962 | 8 | OD or ID, IP | 30 or 19 | | 30 or 19 |
| 4136 | 8 | OD, IP | 30 | | 30 |
| 4841 | 8 | OD, IP | 30 | | 30 |
| 6180 | 9 | OD, IP | 31 | 24 | 27.5 |
| 6682 | 34 | OD, IP | 60 | 53 | 56.5 |
| 6786 | 10 | OD, IP | 33 | 26 | 29.5 |
| 6825 | 12 | OD, IP | 36 | 29 | 32.5 |
| 6867 | 18 | OD, IP or GC | 44 or 32 | 37 or 25 | 40.5 or 28.5 |
| 6891 | 12 | ID, IP | 28 | 15 | 21.5 |
| 6960 | 8 | OD, IP | 30 | 23 | 26.5 |
| 6971 | 12 | OD, IP | 36 | 29 | 32.5 |
| 6976 | 10 | ID, GC | 15 | 6 | 10.5 |
| 7034 | 10 | OD, IP | 33 | 26 | 29.5 |
| 7051 | 10 | OD, IP | 33 | 26 | 29.5 |
| 7078 | 76 | ID, IP | 94 | 87 | 90.5 |
| 7088 | 64 | ID, IP | 86 | 75 | 80.5 |
| 7112 | 122 | ID, GC | 83+ | 72 | 77.5 |
| 7123 | 16 | OD or ID, IP | 42 or 36 | 35 or 20 | 38.5 or 28 |
| 7150 | 40 | ID, GC | 42 | 25 | 33.5 |

Figure 3. Vertilog interpretation, well FF-35B 11/11/1989.[15]

[15] Ex. II-5 (SCG00155502).

Additional flaws of Vertilog were its inability to distinguish between defects and hardware (such as centralizers and scratchers) and its difficulty interpreting corrosion located near the surface casing shoe. Accordingly, alternate methods of presenting Vertilog data, described as "Digital Vertilog" and consisting of reporting the signal from each flux leakage sensor, were discussed in publications by Atlas Wireline Services in 1987[16] and 1991.[17] These papers concluded that transmitting the entire signal seen by the sensor coils better depicts the condition of a casing in a well and provides more information regarding the physical parameters of the "anomaly." The 1991 paper reported that log presentation of the type shown in Figure 1 above was preferable for estimating the penetration of a defect; but regarding corrosion near the surface casing shoe, the 1987 paper reported that what appears to be severe corrosion on the standard log format is properly identified as minor corrosion when using the 12-channel log format.

Starting in approximately the early 2000s, Vertilog evolved into MicroVertilog (MVRT).[18] The MVRT tool was equipped with ten each flux leakage and eddy current sensors, similar to the Vertilog tool. MVRT output was more sophisticated than Vertilog and, in addition to maximum hflux leakage and maximum eddy current, it included output from all of the flux leakage and eddy current sensors, as well as "defect maps" displaying graphical representations of flux leakage and eddy current data.

However, although MVRT presented data in a more sophisticated manner, it was found to be essentially functionally equivalent to Vertilog, and MVRT had questionable accuracy and reliability as well. As illustrated below, like Vertilog, MVRT consistently and significantly overestimates pit depth (Table 2).[19]

[16] Ex. II-6 (Mato, S.A., "Multi-Channel Casing Inspection Instrument," 87-DT-102).
[17] Ex. II-3 (SPE 22101).
[18] Ex. II-7 (Al-Ajmi, M.F., et al., "North Kuwait Down-hole Corrosion Management Challenge and the Use of New Corrosion Detection Tools to Define the Extent of the Problem," SPE 81442, 2003).
[19] Ex. II-8 (Newman, M.A., "The Importance in Developing a Surveillance Logging Quality Assurance and Quality Control Plan," SPE 84828, 2003).

| | MVRT Data | | | Physical Measurements | | |
|---|---|---|---|---|---|---|
| Example | Model | Length (in) | Depth (%) | Length (in) | Width (in) | Depth (%) |
| 1 | GC | 1.7 | 100 | 1.75 | 3.00 | 69.1 |
| 2 | GC | 0.7 | 83.5 | 1.0 | 1.5 | 53.8 |
| 3 | IP | 1.4 | 42.9 | 1.5 | 1.5 | 18.0 |
| 4 | IP | 1.4 | 44.1 | 2.00 | 3.00 | 24.5 |

**Table 2 Comparison of MVRT with Physical Measurements of Large Diameter Pits (GC: general corrosion, IP: isolated pitting, LDC: large diameter corrosion)**

C. Due to Limitations with Vertilog, Superior Tools Such As High Resolution Vertilog (HRVRT) and Ultrasonic Imager Tool (USIT) Were Developed.

HRVRT was developed because of limitations with Vertilog technology. As discussed, first generation MFL tools did not generate very accurate or reliable results.[20]

The Baker Hughes HRVRT used a greater number—and better quality—sensors, resulting in increased circumferential and axial resolution. The 1 ¼-in coil type sensors were replaced with ¼-in Hall-effect sensors.[21] As further comparison, an HRVRT tool used 7-in to 9 ⅝-in diameter casing and contained 288 flux leakage sensors and 96 discriminators (discriminators perform the function of the previously used eddy current sensors). Vertilog and MVRT tools utilized only 10 to 12 each flux sensors and eddy current sensors.

HRVRT reports provide the benefit of indicating metal loss feature dimensions (length, width, and depth), identifying metal loss as internal or external, classifying features (pinholes, pits, general, axial grooving, axial slotting, circumferential grooving, and circumferential slotting), and calculating safe operating pressure. Classification of metal loss features is based on width and length as shown in Figure 4.

[20] *See supra* note 9, Ex. II-2 (citing Goedecke, H., GE Oil & Gas“Ultrasonic or MFL Inspection, Which Technology is Better for You?,” Pipeline & Gas Journal, October 2003).
[21] Ex. II-9 (El Sherbeny, W., et al., “Magnetic Flux Leakage (MFL) Technology Provides the Industry’s Most Precise Pipe Integrity Corrosion Evaluation, Accurately Characterizing Casing and Tubing Strength - Technology Overview and Case History,” SPE 175871-MS, 2015).

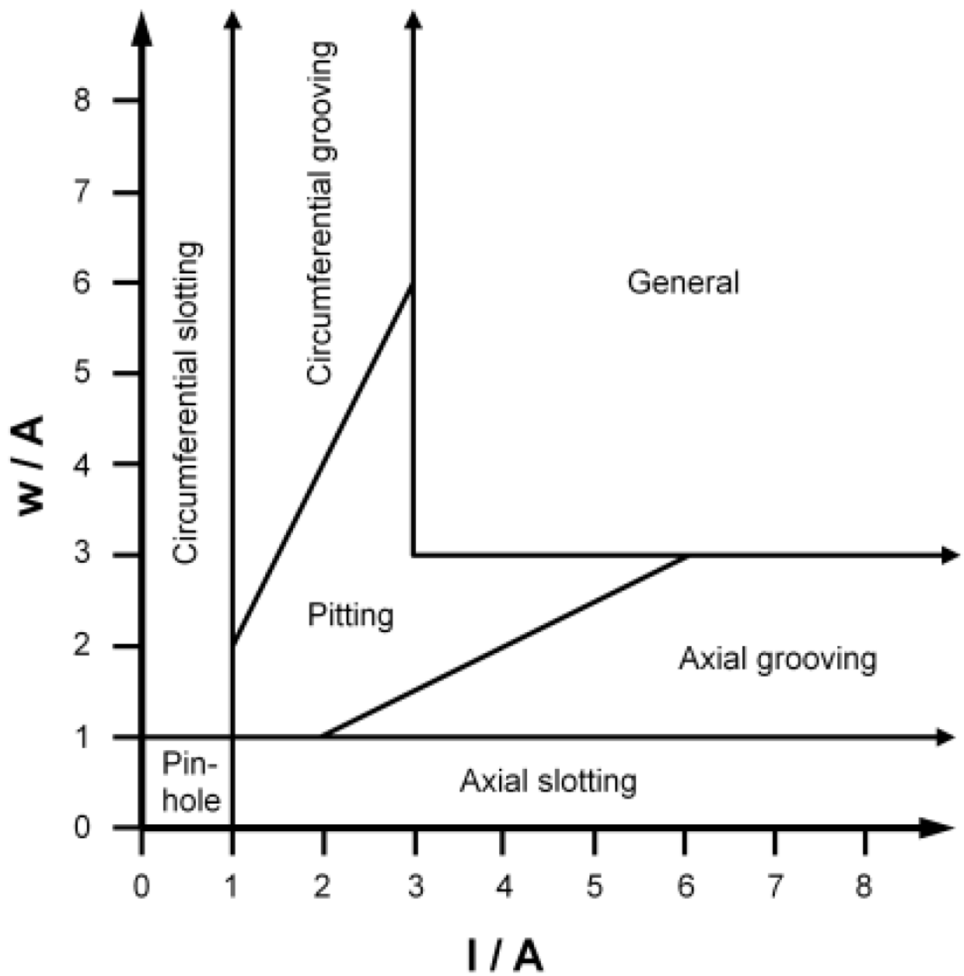


Figure 4. Graphical presentation of surface dimensions of metal loss anomalies (w is width, l is length, and t is wall thickness).[22] If t<10 mm then A=10 mm. If t>10 mm then A=t.

The Schlumberger Ultrasonic Imager Tool (USIT) was also developed and is superior to Vertilog; and it is also complementary to HRVRT. Unlike MFL, analysis of which requires accounting for metal loss shape in order to estimate depth, ultrasonic logging tools perform direct measurements of casing radii and wall thickness.[23]

Ultrasonic signal processing yields four measurements of casing thickness, internal radius, internal wall smoothness and acoustic impedance of materials in the annulus.[24] Ultrasonic pipe

[22] Ex. II-10 (Specifications and Requirements for In-Line Inspection of Pipelines, Pipeline Operators Forum, Version 2016).

[23] Ex. II-11 (Rushing, J., "Casing Mechanical Integrity Tests Utilizing Wireline Ultrasonic Imaging Logs," Geothermal Resources Council Transactions, Vol. 25, 2001).

[24] Ex. II-12 (Al-Saadi, et al., "Well Side-Track Optimization Using Electromagnetic and Ultrasonic Measurements Across Dual Strings for Well Integrity Assurance," IADC/SPE-180679-MS, 2016).

imaging tools yield excellent pipe thickness information with superior azimuthal resolution. Pipe thickness coupled with internal radii measurements make the reliability of this tool "fair" in determining internal and external corrosion.[25]

D. Follow-up Analyses by More Accurate Methods—USIT and HRVRT—Confirmed that the Circa 1988 Vertilogs Returned False Positives and Were Therefore Not Reliable.

Comparison of wells that were inspected by Vertilog circa 1988 and inspected subsequently by HRVRT and USIT demonstrates that Vertilog did not provide reliable data.

1. Of the five wells on the 1988 list with vendor-quantified Vertilog results, one well (SS-9) was subsequently logged almost 30 years later using both USIT and HRVRT. An additional well (FF-35B) not on the 1988 list was inspected using Vertilog in 1989 and also subsequently logged using both USIT and HRVRT. Review of logging results of these two wells shows that metal loss identified by Vertilog circa 1988 was not substantiated by subsequent logging, even after close to 30 years of additional service.

2. Vertilog inspection of the SS-9 7-in casing in December 1988 identified Class 2 features in six casing joints between 2100 ft and 3800 ft (Figure 5). All of the features identified by Vertilog were indicated as isolated pitting, all were located immediately above casing collars, and all appeared similar even though three were identified as internal and three were identified as external. Multiple occurrences of similar signatures that were not identified as metal loss exist on the Vertilog chart.

3. USIT and HRVRT of the SS-9 7-in casing were performed in 2018 as part of SoCalGas' comprehensive safety review and did not identify any of the metal loss features identified by Vertilog. USIT and HRVRT did not identify features greater than 20% of casing thickness. USIT identified anomalies from 1628 to 1630 ft and from 2560 to 2570 ft that were reported as tool "eccentering." HRVRT did not identify any metal loss features greater than 18% wall thickness above 8522 ft.[26] Internal metal loss of 23% and 81% was identified by HRVRT at 8522 ft and 8543 ft, respectively.

4. Vertilog inspection of the FF-35B 8 ⅝-in casing in November 1989 identified multiple Class 2, 3, and 4 indications (Figure 7). The Class 3 and Class 4 Vertilog indications were not corroborated by the 2016 HRVRT and 2017 USIT logs, even though these logs were conducted 27 and 28 years after the Vertilog inspection (Figure 7). HRVRT did not identify external metal loss deeper than 21% of wall thickness and did not identify internal metal loss deeper than 26% of wall thickness. USIT did not identify metal loss greater than 19% of wall thickness, except for an area reported as 21.4% metal loss at 7020 ft depth.

5. In summary, the circa 1988 Vertilogs did not provide reliable casing metal loss data.[27]

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[25] Ex. II-13 (Singh, S.K., "An Integrated Approach to Well Integrity Evaluation via Reliability Assessment of Well Integrity Tools and Methods: Results from Dukhan Field, Qatar," SPE 156052, 2012).
[26] HRVRT has a reporting threshold of 15% casing thickness loss.
[27] Figures 5 through 9 display only anomalies that I have interpreted to be caused by potential wall loss. They do not include any anomalies that appear to reflect mechanical damage.

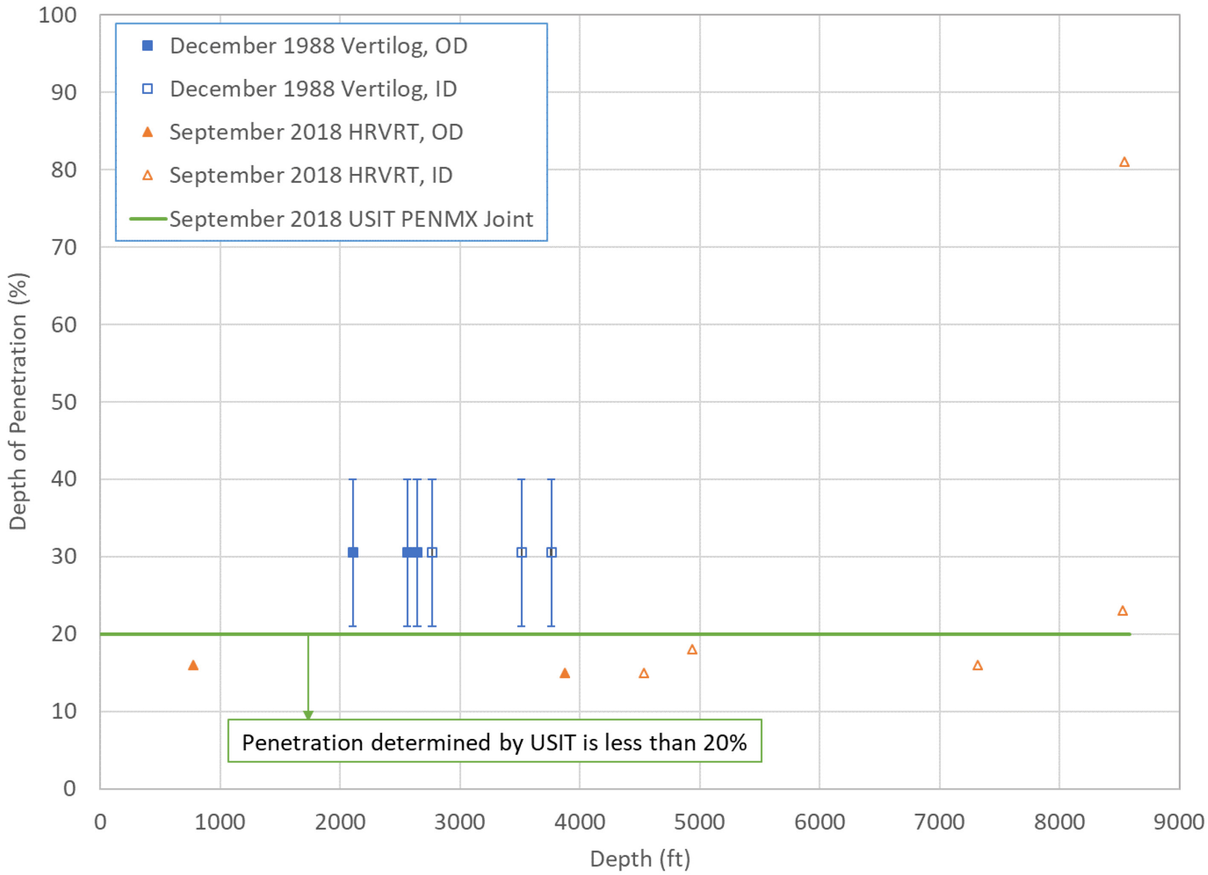


Figure 5. Comparison of SS-9 7-in casing 1988 Vertilog, 2018 HRVRT, and 2018 USIT results. [28] Depth of penetration into the casing is shown on the vertical axis. Depth along the casing into the well is shown on the horizontal axis. Vertilog results are shown as vertical blue lines spanning the range of the identified indication class. USIT did not detect penetration greater than 20%, as indicated by the solid green line. External HRVRT indications are denoted by the solid orange triangles. Internal HRVRT indications are denoted by the open orange triangles.

- HRVRT and USIT of the P-46 7-in casing were performed during the 2017 SIMP program and no metal loss features greater than 20% of casing thickness were found, even though the 1988 Vertilog inspection identified ten casing joints as having Class 2 damage.[29,30] USIT of the Porter 46 7-in casing identified an unspecified anomaly in the range 3970 ft to 3984 ft. The nature of the anomaly was not described, but review of the USIT log suggests the existence of mechanical deformation or damage in this area. No such anomaly was reported by HRVRT. An August 25, 2017 email from SoCalGas to DOGGR stated "After reviewing the P46 log results at

[28] Ex. II-14 (SCG00171338; SCG00171339); Ex. II-15 (DOGGR_03700762_Vertilog_12-16-1988; DOGGR_03700762_SS 9_CsgInsp_09-06-2018; DOGGR_03700762_SS 9_USIT_09-07-2018).
[29] Ex. II-16 (DOGGR_03700733_USIT-GR-CCL_8-16-2017).
[30] Ex. II-17 (0403700733_Porter_46_CSGINSP_Final_Report_08-17-2017).

length, we have elected to run a 5.5" inner string and cement it to 2706.'"[31] The reason for installing the innerstring was not stated.

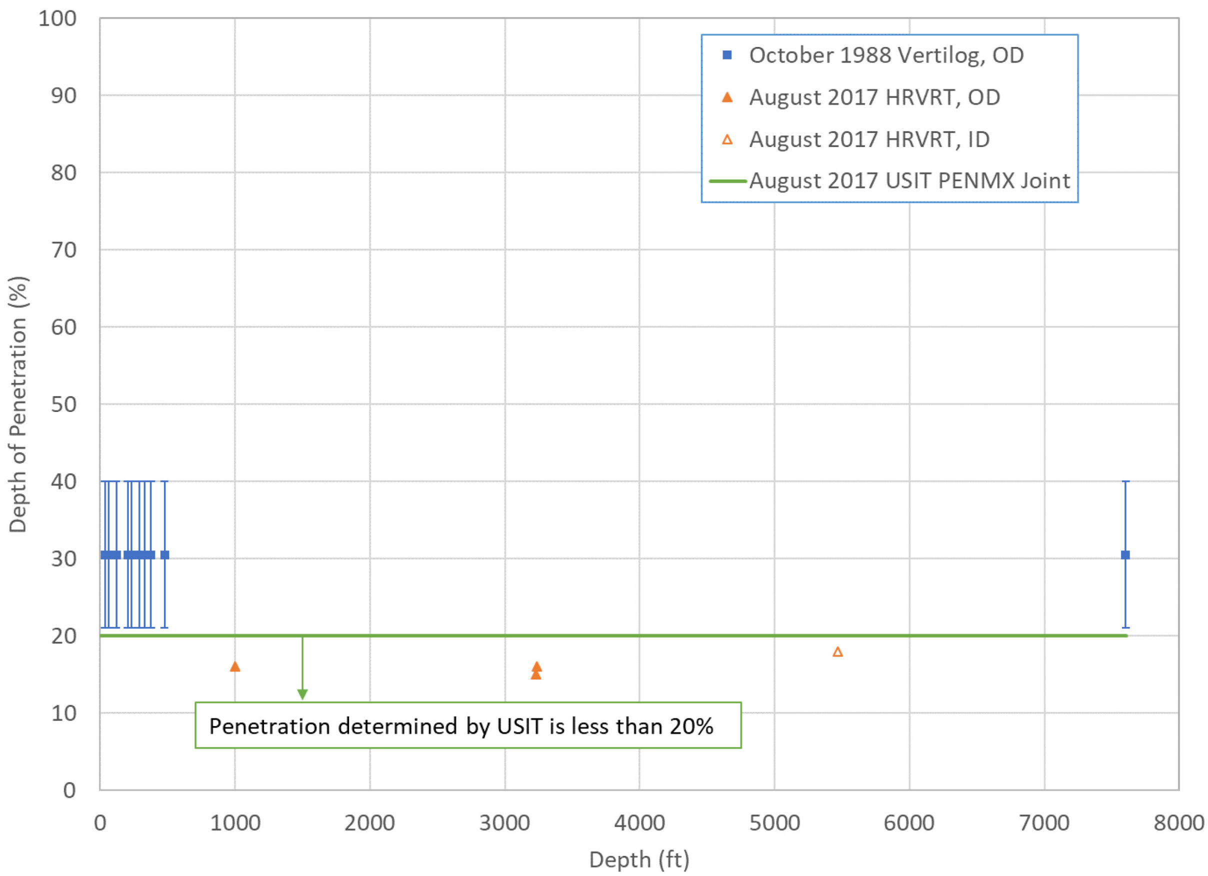


Figure 6. Comparison of P-46 7-in casing 1988 Vertilog and 2017 USIT results.[32] Depth of penetration into the casing is shown on the vertical axis. Depth along the casing into the well is shown on the horizontal axis. Vertilog results are shown as vertical blue lines spanning the range of the identified indication class. USIT did not detect penetration greater than 20%, as indicated by the solid green line. External HRVRT indications are denoted by the solid orange triangles.[33] Internal HRVRT indications are denoted by the open orange triangles.

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[31] Ex. II-18 (DOGGR_03700733_DATA_03-19-2008 (Modified 3-7-2018).pdf; at 72).
[32] Ex. II-19 (SCG00134366; SCG00134367); Ex. II-20 (DOGGR_03700733_Vertilog_10-19-1988; DOGGR_03700733_USIT-GR-CCL_8-16-2017).
[33] Ex. II-17 (040370073300_P46_CsgInsp_08-17-2017).

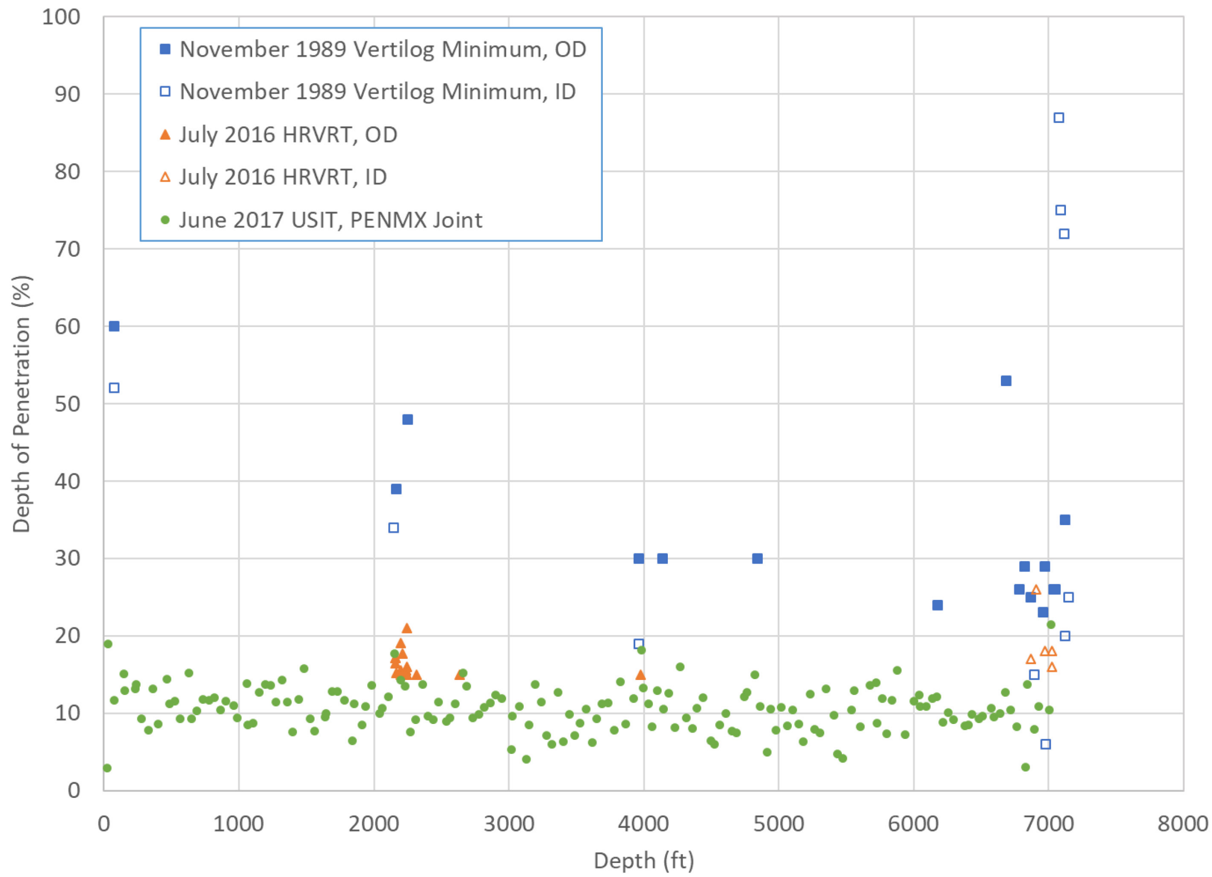


Figure 7. Comparison of FF-35B 8 ⅝-in casing 1989 Vertilog, 2016 HRVRT, and 2017 USIT results. [34] Depth of penetration into the casing is shown on the vertical axis. Depth along the casing into the well is shown on the horizontal axis. Vertilog results are shown as blue squares and USIT results are shown as green circles. External HRVRT indications are denoted by the solid orange triangles. Internal HRVRT indications are denoted by the open orange triangles.

[34] Ex. II-5 (SCG00155502); Ex. II-21 (DOGGR_03721458_FF 35B_USIT_06-01-2017a; DOGGR_03721458_FF 35B_USIT_06-01-2017b; DOGGR_03721458_FF 35B_CsgInsp_07-14-2016a; DOGGR_03721458_FF 35B_CsgInsp_07-14-2016b).

- USIT of the F-4 7-in casing (with the inner-string removed) was performed in 2016 as part of SIMP and no significant corrosion was found in the two areas that had been previously identified as having Class 4 damage based on the 1988 Vertilog inspection.[35]

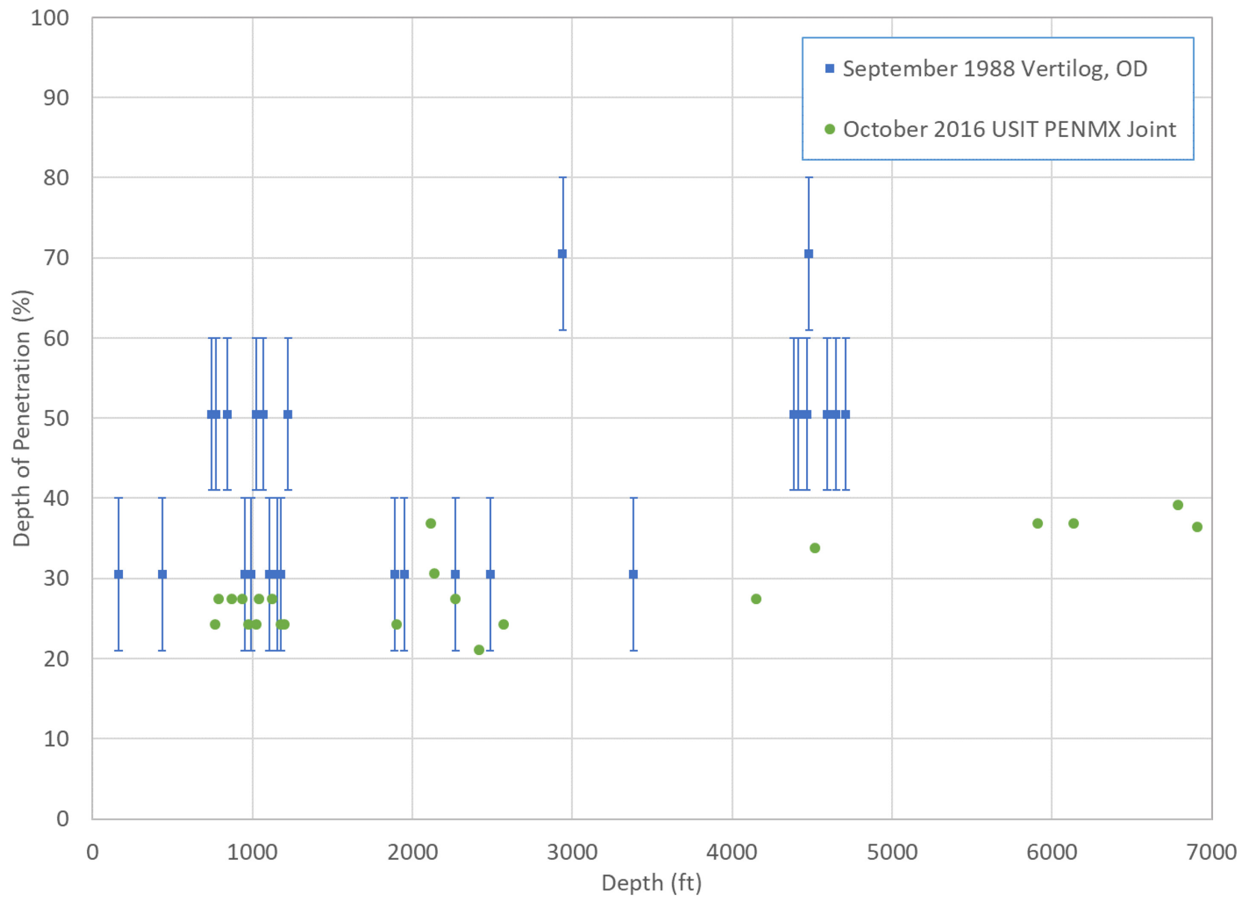


Figure 8. Comparison of F-4 7-in casing 1988 Vertilog and 2016 USIT results.[36] Depth of penetration into the casing is shown on the vertical axis. Depth along the casing into the well is shown on the horizontal axis. Vertilog results are shown as vertical blue lines spanning the range of the identified indication class. USIT data showing penetration greater than 20% is represented by the green circles.

- USIT of the SS-8 7-in casing was performed on 4-24-2013 and no significant corrosion was found in the areas that had been identified by the 1989 Vertilog inspection as having Class 2 and Class 3 damage.[37] While the significance of corrosion depends on the depth and size of the defect, generally local metal loss below 50% of wall thickness should not be

[35] Ex. II-22 (03700667_F 4_USIT_10-19-2016).
[36] Ex. II-23 (DOGGR_03700667_Vertilog_9-6-1988; SCG00160071; SCG00160072); Ex. II-24 (03700667_F 4_USIT_10-19-2016).
[37] Ex. II-25 (DOGGR_03700761_USIT_Gamma Ray Neutron_4-24-2013).

considered significant because it does not threaten the integrity of the well. In other words, the 20%-30% wall loss indicated by USIT below is not significant because such loss does not affect the integrity of the well.

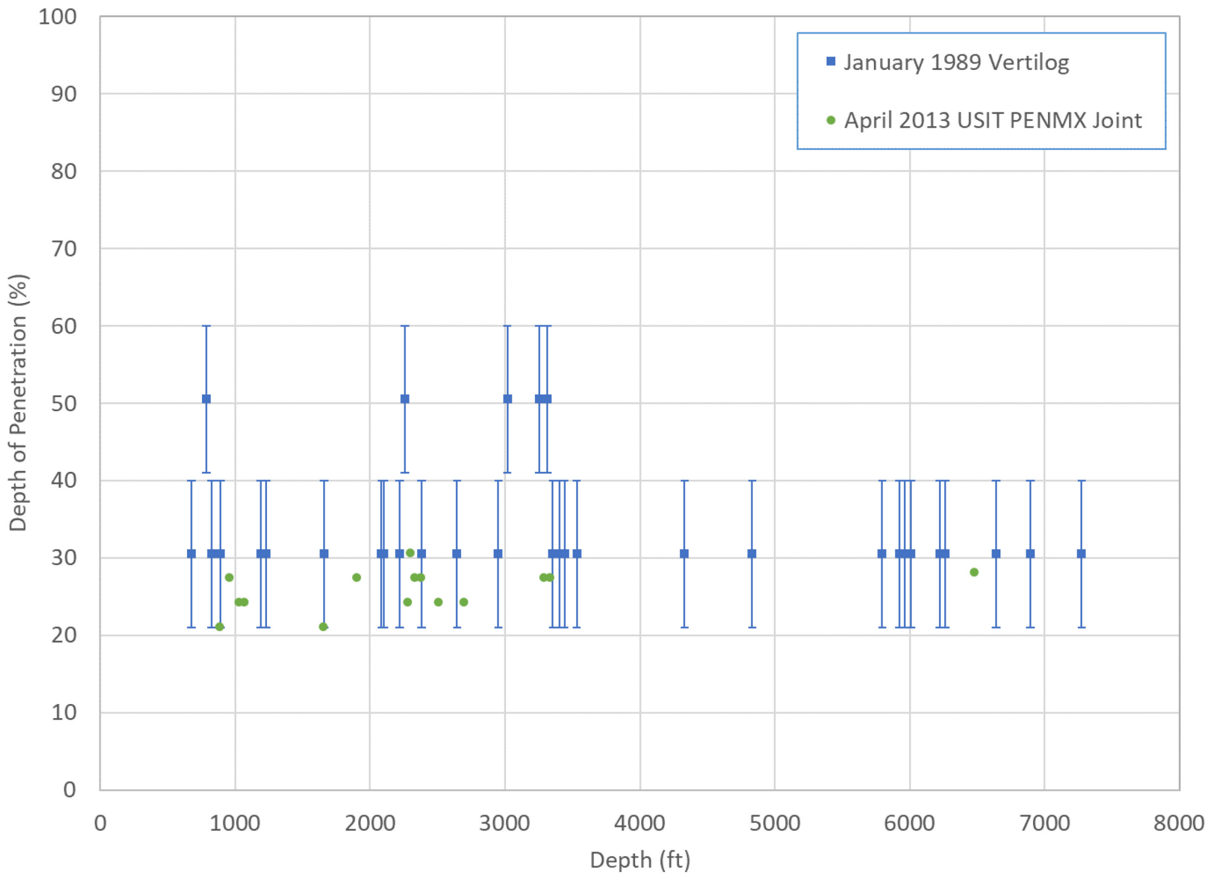


Figure 9. Comparison of SS-8 7-in casing 1989 Vertilog and 2013 USIT results.[38] Depth of penetration into the casing is shown on the vertical axis. Depth along the casing into the well is shown on the horizontal axis. Vertilog results are shown as vertical blue lines spanning the range of the identified indication class. USIT data showing penetration greater than 20% is represented by the green circles.

## II. PAO WRONGLY ASSUMES THAT THE CIRCA 1988 VERTILOG RESULTS WERE A RELIABLE INDICATOR OF CORROSION ISSUES ON SS-25.

PAO claims that "SoCalGas could have performed a simple analysis of the rate at which external corrosion was impacting the wells in Aliso Canyon, including SS-25," subsequently monitored and/or remediated issues with SS-25, and prevented the leak.[39] PAO further alleges the following:

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[38] Ex. II-26 (SCG00170710; DOGGR_03700761_Vertilog_1-17-1989); Ex. II-25 (DOGGR_03700761_USIT_Gamma Ray Neutron_4-24-2013).

[39] PAO Prepared Testimony at 7.

> SoCalGas has not demonstrated that it attempted to use the 1988 Vertilog results to assess the risk of well corrosion in its seven wells specifically or the Aliso Canyon wellfield more broadly. Had SoCalGas' management properly administered the program, the corrosion issues on SS-25 would have been timely identified. SoCalGas would then have been able to monitor or remediate or monitor the well and prevent the October 23, 2015 Leak.[40]

PAO's argument is incorrect, and PAO's entire premise is undermined by the fact that calculating the corrosion rate requires much more than a "simple analysis." PAO's calculated corrosion rates are speculative and unreliable, as PAO calculated its rates merely by dividing a single casing thickness measurement by the maximum penetration from the Vertilog reports by the length of time that the wells were in service. This method is insufficient as it does not consider the many well-specific variables requiring analysis. External corrosion rates of an underground structure depend on availability of water, the chemistry of the water, soil and/or formation chemistry and resistivity, oxygen concentration, and the presence of certain microbes. Corrosion rates also often change over time due to changes in environmental conditions.

Accordingly, SoCalGas could not have simply used PAO's calculation method to identify corrosion issues at Aliso Canyon generally, much less at SS-25. As Blade stated, "There is **no way to know** what an inspection of the SS-25 casing would have shown in 1988…"[41] Nonetheless, PAO and Blade estimate that SS-25 was already undergoing appreciable corrosion at the time of the Vertilog testing. One of Blade's estimates provides that corrosion at SS-25 started in 1977, based on a linear corrosion rate of 7 mpy and the fact that corrosion reached 85% maximum depth in the SS-25 7-in. casing in 2015.[42] Blade also estimated a linear corrosion rate range of 5 to 10 mpy.[43] Assuming a rate of 10 mpy, Blade's estimate provides that corrosion could have started in 1988 and reached maximum measured depth of 85% in 2015. PAO estimated corrosion rates of 1.4 to 4.6 mpy for wells on the 1988 list that were inspected using

[40] PAO Prepared Testimony at 9.
[41] Blade Supplemental Report, "Review of the 1988 Candidate Wells for Casing Inspection," at 2 (emphasis added).
[42] Blade Supplemental Report "SS-25 Casing Failure Analysis," p. 209.
[43] Blade Report at 123.

Vertilog.[44] But even according to PAO's **authority**,[45] none of those purported corrosion rates warrant any action.

To the contrary, it is likely that external corrosion of the SS-25 7-in. production casing did not initiate until after the 1988 to 1990 time frame, in which case **there would have been no corrosion for a Vertilog to detect**. External corrosion of a production casing contained within a surface casing is unlikely to initiate until sufficient drilling fluid is displaced by water. The amount of time for this to occur is not known, and indeed, can take many years, if it happens at all.

Critically, the grooved, striated appearance of the SS-25 corrosion is consistent with Microbiologically Influenced Corrosion (MIC).[46] This is important because corrosion associated with MIC typically occurs at rates greater than Blade's estimated corrosion rate range of 5 to 10 mpy. Given the 85% corrosion depth reached in 2015, it is thus likely that any corrosion at SS-25 started many years **after** the circa 1988 Vertilog testing.

PAO and Blade appear to believe that methanogens caused the corrosion at SS-25, but neither Blade nor PAO considered species more commonly associated MIC. Blade acknowledged in its November 1, 2019 webinar that it did not perform sufficient testing to adequately characterize bacteria present on the SS-25 surface casing.[47] In addition, microbial communities are known to change substantially when environmental conditions change. No testing for microbes was conducted on samples removed from the area of the rupture at the time the ruptured casing was extracted from SS-25 in November 2017, and even by then the makeup of the microbial community had likely changed completely since the rupture. Test results identifying methanogenic microbes were taken from 7-in casing section 24 at a depth of 979 feet and 7-in casing section 25 at a depth of 1021 feet. These locations are 87 feet and 129 feet below

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[44] PAO Prepared Testimony at 8.

[45] PAO Prepared Testimony at 8 n. 39 ("In an open water system a corrosion rate of around 1 MPY is normal. Having corrosion rate of around 10, you should take action. Corrosion rates of 20 MPY and above, you should be concerned, as the corrosion is 'eating' the metal rather fast." Merus Oil and Gas, https://www.merusonline.com/mpy-milsper-year/).

[46] Ex. II-27 ("Microbiologically Influenced Corrosion (MIC): Methods of Detection in the Field," GRI Field Guide 1991, Gas Research Institute, Chicago, Illinois).

[47] Blade Root Cause Analysis Webinar, November 1, 2019 (recording available at https://www.youtube.com/watch?v=K67dIl6aapk&feature=youtu.be).

the rupture, respectively. The MIC samples were acquired in August 2018, as sections 24 and 25 were removed from the well, nine months after the ruptured casing section was removed from SS-25 and nearly three years after the rupture occurred. It is unreasonable to expect that microbes present in these samples were representative of microbes that existed in the area of the rupture at the time of the rupture.

Reports of corrosion caused by methanogens are rare, but sulfate reducing bacteria can cause MIC and are frequently associated with corrosion of below-ground steel structures. The typical pitting corrosion rates of 28 mpy for unprotected line pipe steel in the presence of sulfate reducing bacteria are reported in the technical literature.[48] At 28 mpy, the SS-25 7-in. casing would have corroded to the maximum measured depth of 85% in just under ten years (**Figure 10**)—meaning that no corrosion would have been present as late as 2005. Indeed, MIC pitting rates greater than 250 mpy have even been reported in the technical literature.[49]

[48] Ex. II-28 (Jack, Thomas R., "Biological Corrosion Failures," ASM Metal Handbook 10th Edition, Volume 11, ASM International, 2002).

[49] Ex. II-29 (Larsen, K.R., "A Closer Look at Microbiologically Influenced Corrosion", Materials Performance, July 2015).

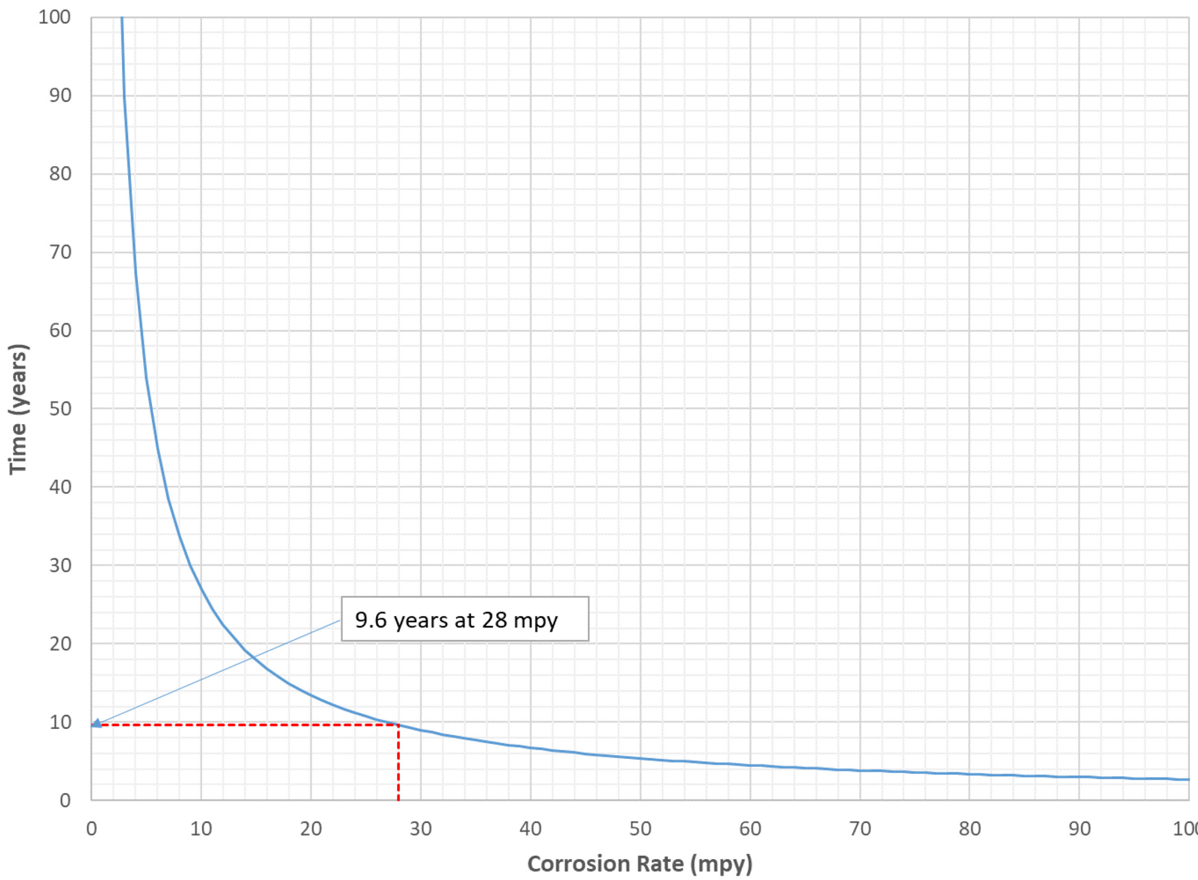


Figure 10. Time for corrosion to advance 85% through the thickness of a 7-in. 23 pound per foot casing.

## III. CONTRARY TO PAO'S ASSERTION, PRESSURE TESTS ARE PRIMARILY USED TO IDENTIY EXISTING LEAKS AND CRITICALLY SIZED DAMAGE."[50]

PAO is incorrect that pressure testing done following the Vertilogs would have revealed mechanical integrity issues with SS-25. Specifically, PAO argues the following:

> [P]ressure testing would also have assessed the mechanical integrity of the wells. Therefore, SoCalGas should have followed up with further testing of the integrity of the 13 remaining wells. Had SoCalGas done so, it may have discovered an integrity issue on SS-25 during the Vertilog and subsequent pressure-testing program and would have been able to take appropriate steps to remediate or monitor the condition of SS-25.[51]

PAO's allegations are based on a misunderstanding about the function of pressure testing

[50] PAO Prepared Testimony at 6. Moreover, when SoCalGas asked PAO to identify all tools available in or around 1988 that were capable of detecting corrosion on the outer diameter of casings in gas storage wells, PAO responded: "Pressure testing was an available method of identifying the integrity of casings in gas storage wells in 1988." Ex. II-30 (PAO Response to SoCalGas First Set of Data Requests, response to Question 2).

[51] PAO Prepared Testimony at 6-7.

and interpretation of pressure testing results. Pressure testing is intended to detect existing casing leaks, not wall loss. As established above in the discussion of USIT and Vertilog, there was no critically sized damage in these wells. Put differently, pressure testing would not reveal a casing leak absent severe pre-existing corrosion, and such testing will only confirm the absence of critically sized damage.

To illustrate, we used the modified B31G method described by ASME B31G to calculate safe operating pressure of corroded 7-in., 23 pound per foot J55 casing, which is the type of casing that was used in the upper portions of the aforementioned seven Vertilog-tested wells at Aliso Canyon (Figure 11).[52]

Our calculations show, for example, that safe operating pressure of a casing with local metal loss of up to 50% wall thickness (Vertilog mid-range Class 3) and 10-in length, is greater than the 115% MAOP (3625 psi) mechanical integrity test pressure required by current California regulations (Figure 11).

Our calculations further show that safe operating pressure for casing with metal loss up to 60% wall thickness (boundary between Vertilog Classes 3 and 4) and 10-in length is above the approximately 3150 psi casing MAOP.

As shown below, pressure testing only reveals critical defects.[53] Of the wells listed in the 1988 memo that were pressure tested, pressure testing was performed no higher than 115% MAOP. Therefore, PAO's allegation that pressure testing would have revealed integrity issues for SS-25 is pure speculation.

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[52] Ex. II-31 (Manual for Determining the Remaining Strength of Corroded Pipelines, ASME B31G-2012).

[53] PAO states that "There is no minimum amount of corrosion or metal loss that should necessitate remediation; instead, once the wellbore is proven to be found in a corrosive environment, such a finding would "necessitate immediate remediation." Ex. II-30 (PAO Response to SoCalGas First Set of Data Requests, response to Question 3). PAO's response could not be further from reality.

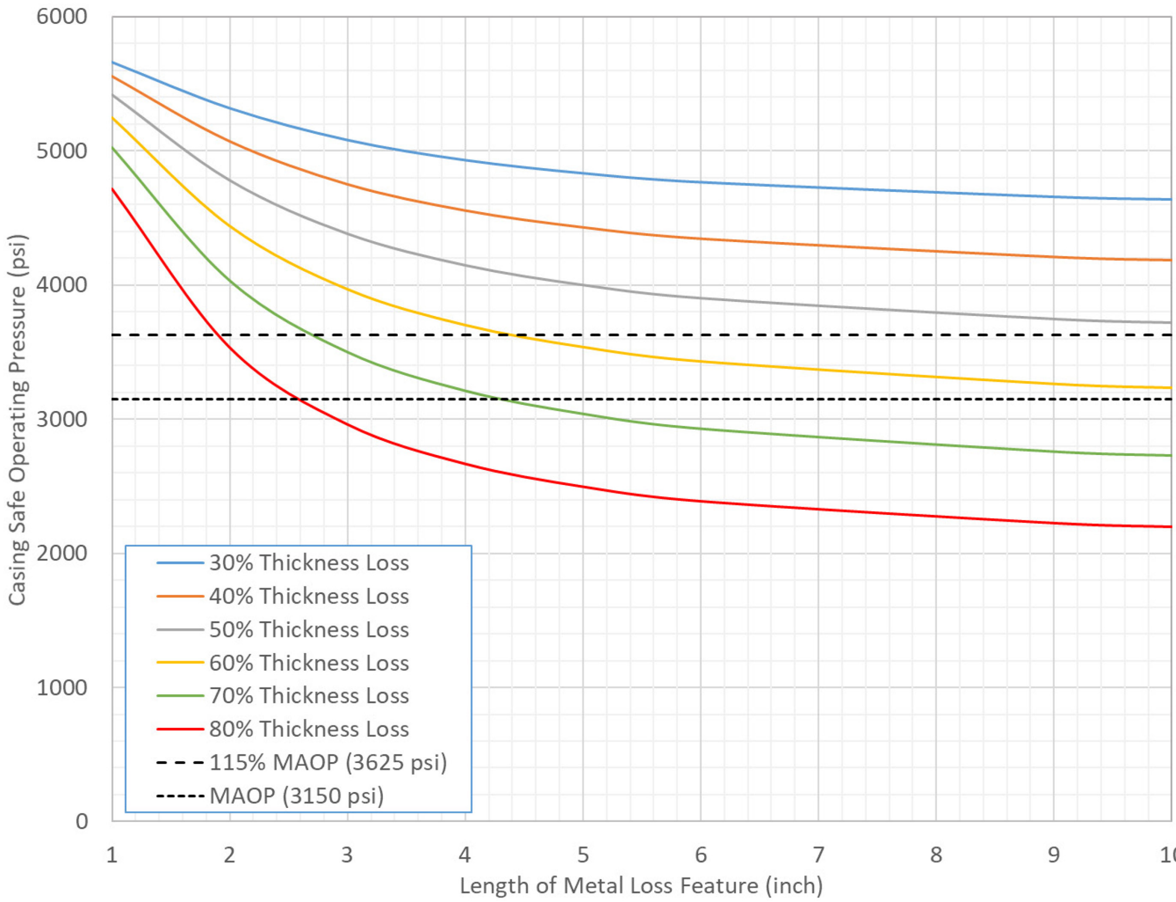


Figure 11. Modified B31G casing safe operating pressure determined for longitudinal metal loss features with depths varying from 30% to 80% of wall thickness and lengths varying from one to ten inches.

## IV. PAO AND SED BOTH INCORRECTLY ASSUME THAT CATHODIC PROTECTION (CP) WOULD HAVE PREVENTED THE LEAK.

PAO alleges "[t]he fact that SS-25 was not cathodically protected, replaced, or taken out of service prior to the leak, meant that the corrosion was unmitigated. SoCalGas was, or should have been, aware of this issue. However, despite the Storage Engineering Manager's warnings six and a half years prior, SoCalGas did not take the necessary steps to prevent or manage the corrosion."[54] PAO further states "[i]f cathodic protection were applied to SS-25 prior to the invasion of groundwater, the resulting corrosion would not have occurred."[55] SED makes a similar contention.[56]

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[54] PAO Prepared Testimony at 11.
[55] Ex. II-30 (PAO Responses to SoCalGas First Set of Data Requests, response to Question 14).
[56] SED Opening Testimony at 45 ("A cathodic protection system would have provided corrosion protection to the 11 ¾-inch casing.").

This is not so. Cathodic protection (CP) does not protect production casing where it is contained within surface casing. CP will protect only the outermost casing of a multiple casing string, and therefore could not have protected the SS-25 7-in. casing at the rupture location. In a well where multiple casing strings are used, external cathodic protection will only protect that portion of each casing string in contact with the formation.[57] The SS-25 7-in. casing failure occurred at a depth of 892 ft, a location where the 7-in. casing is contained within the 990 ft. deep 11 ¾-in surface casing. Cathodic protection would not have protected the 7-in. casing above 990 ft. In fact, PAO acknowledged, as did Blade, that CP would not have protected the 7-in. casing inside the 11 ¾-in casing.[58]

In addition, CP of the surface casing was not necessary. There is no conclusive evidence that there were holes in the 11 ¾-in surface casing prior to rupture of the production casing. And, even if that were the case, Blade found that water entered the B-annulus through the casing shoe.[59] In any event, Blade also concluded that the holes in the 11 ¾-in surface casing were likely a "consequence of"—not a cause of –the axial rupture of the production casing:

> The holes may have been a consequence of an internal pressure of 800 psi or higher. The pressure in the surface casing annulus surged to 800 psi at one point right after the axial rupture. **The holes are likely a consequence of the axial rupture.**[60]
>
> The gas flowing through the axial rupture on the 7 in. production casing caused an increase in pressure on the 11 3/4 in. surface casing. This caused several of the surface casing corroded regions to fail, creating holes and thus providing a pathway for gas to escape. Over 50 such holes provided a pathway for the gas to surface.[61]

Although Blade stated, "Some of these approximately 58 holes [in the 11 ¾-in surface casing] **could** have existed prior to the 7 in. casing axial rupture," in the next sentence in its RCA Report, Blade states: "Many of the holes exhibited sharp corners that may have been more typical

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[57] Ex. II-32 (J.H. Morgan, Cathodic Protection, Second Edition, NACE International, 1987, p. 222).
[58] Ex. II-30 (PAO Responses to SoCalGas First Set of Data Requests, response to Question 14 ("While a cathodic protection system would have provided corrosion protection to the 11 3/4 in. casing, it would not have protected the 7 in. casing inside the 11 3/4 in. casing.") (quoting Blade May 16, 2019 Report, p. 215)).
[59] Blade Report at 100.
[60] Blade Report at 119 (emphasis added).
[61] Blade Report at 3.

of a burst failure, implying that **they occurred due to a pressure surge in the surface casing**."[62]

PAO further ignores that CP can be ineffective and even harmful to neighboring wells. CP might be ineffective if MIC is simultaneously occurring because MIC can increase the kinetics of corrosion reactions, increasing the required CP current, and in turn increasing the risk of undesirable results such as stray currents.[63] MIC in some cases cannot be stopped by CP, even when using very large negative potentials.[64] Moreover, CP installation at SS-25 could have been detrimental to wells SS-25A and SS-25B.[65] For example, stray electrical currents from CP can cause accelerated corrosion.[66, 67]

## V. SED IS INCORRECT THAT CONTINUOUS PRESSURE MONITORING AND TEMPERATURE/NOISE SURVEYS SHOULD HAVE ALERTED SOCALGAS TO THE SS-25 LEAK PRIOR TO OCTOBER 23, 2015.

### A. Continuous Pressure Monitoring Would Not Have Allowed SoCalGas to Detect the Leak Before It Occurred.

SED alleges that the lack of continuous pressure monitoring prevented immediate identification of the SS-25 leak and accurate estimation of the gas flow rate.[68] Unlike the Blade report,[69] SED did not go so far as to state that real-time pressure monitoring could have prevented the brittle circumferential parting from occurring. However, SED's sole sponsoring witness Margaret Felts testified that continuous, real-time pressure monitoring would have enabled SoCalGas to shut in the SS-25 well and avoid "catastrophic failure" of the 7-in. casing.[70]

This is wrong. It was not possible to detect a leak and take action prior to the parting of the 7-in. casing because the 7-in. casing was not leaking prior to October 23, 2015. The rupture and parting of the SS-25 7-in. casing occurred in a single, rapid event.

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[62] Blade Report at 119 (emphasis added).

[63] Ex. II-33 (NACE TM0106-2016 "Detection, Testing, and Evaluation of Microbiologically Influenced Corrosion (MIC) on External Surfaces of Buried Pipelines.").

[64] Ex. II-34 (Deltares, S.J., et al., "Cathodic Protection and MIC – Effects of Local Electrochemistry," NACE Corrosion 2017, Paper No. 9452).

[65] *See* SoCalGas Reply Testimony Chapter I (Hower/Stinson) at Section 3.F.

[66] Ex. II-35 (Holtsbaum, Brian W., "Well Casing External Corrosion and Cathodic Protection," ASM Handbook, Volume 13C: Corrosion, ASM International, 2006, p. 97).

[67] Ex. II-36 (NACE-SP0186 discussion of electrical isolation); Ex. II-37 (API-59-199 page 212 for more on stray currents.

[68] SED Opening Testimony at 47.

[69] Blade Report at 230.

[70] Ex. I-10 (Felts Depo. Tr. 270:17).

The Blade main report and various supplemental reports assert that the SS-25 7-in. casing's vertical rupture and circumferential parting were two separate events, with the circumferential parting occurring some period of time after the initial vertical rupture, but while the well was still on injection. To the contrary, it is evident the SS-25 7-in. casing vertical rupture and circumferential parting occurred as a single event, as illustrated in Figure 12 and Figure 13, and for the reasons described below:

- The SS-25 fracture surface exhibits clear chevron marks at a number of locations. Chevron marks denote the direction of propagation of cracks in steels – the apex of the chevron points toward the fracture origin (Figure 14). Chevron marks on the SS-25 fracture surface show clearly that the circumferential fracture is an extension of the axial fracture (Figure 15). This interpretation is consistent with remarkably similar chevron marks shown in a textbook on failure analysis (Figure 16).[71]

- Blade's contention that a separate fracture origin exists on the circumferential portion of the fracture is incorrect (Figure 17). Rather than a fracture origin, this area is merely a continuation of the circumferential portion of the fracture. Fracture surface markings within the hypothesized origin are the same as or similar to those outside of the origin.

- The Blade report says nothing about how this alleged fracture origin came into existence. If the origin was created during the casing manufacturing process or by a sub-critical crack growth mechanism such as fatigue or stress-corrosion, the surface of the origin would appear distinctly different.

- Blade's inability to determine the size of alleged fracture origin (they report it as 5.22 mm deep and either 14.54 mm long or 21.72 mm long[72]) is consistent with the absence of features identifying it as an origin.

- Blade's scanning electron microscope (SEM) photos of the hypothesized origin show predominantly cleavage features.[73] Blade reported that no noticeable changes in fracture mode were observed outside of the origin[74] and their SEM photographs corroborate this. As such, the hypothesized origin must have been created by mechanical force in the same manner as the circumferential parting.

- Blade's analysis of the circumferential parting is logically flawed. According to Blade's analysis and calculations, the origin was required for circumferential parting to occur as a separate event. But the fracture mode of the origin is the same as that of the circumferential parting, begging the question as to how the

[71] Ex. II-38 (Wulpi, Donald J., Understanding How Components Fail, American Society for Metals, 1985, p. 91).
[72] Blade Supplemental Report, SS-25 Casing Failure Analysis, at 166.
[73] Blade Supplemental Report, SS-25 Casing Failure Analysis, at 140-142.
[74] Blade Supplemental Report, SS-25 Casing Failure Analysis, at 143.

origin came into existence, since mechanical loads were insufficient to cause a separate circumferential parting in the absence of the origin.

- For there to have been a circumferential fracture separated in time from the vertical fracture, the vertical fracture would have to arrest (stop). There is no fractographic evidence showing arrest of the vertical fracture extending upward from the area of the burst. The vertical fracture extending downward from the area of the burst arrested most likely because it was approaching thicker material at the casing threaded connection.

- The 7-in. casing did not have to become cold for the circumferential fracture to occur. The fracture that extended vertically upward from burst area did not require cooling of the material. Similarly, no further cooling would be required for this fracture to change direction and propagate circumferentially.

- There is no mechanical reason for the upward extending vertical fracture to arrest. The stress intensity at the tip of the fracture, essentially the driving force for fracture, was increasing as the fracture became longer.

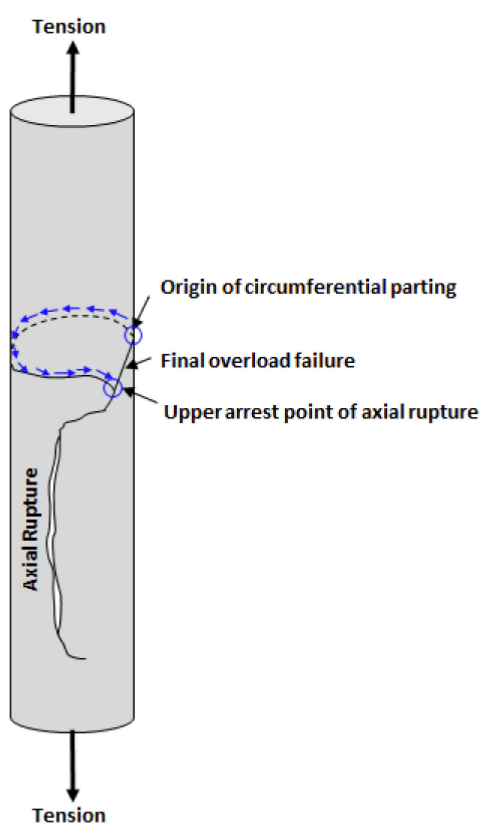


Figure 12. Left: Figure 70 from page 73 of Blade main report. Right: Corrected Figure 70 with red arrows added, which in addition to existing blue arrows, show actual crack propagation direction. The upper vertical fracture did not arrest abruptly at the location indicated by Blade. The circumferential fracture simply ran into the existing (mostly) vertical fracture and stopped (location of lowest blue arrow).

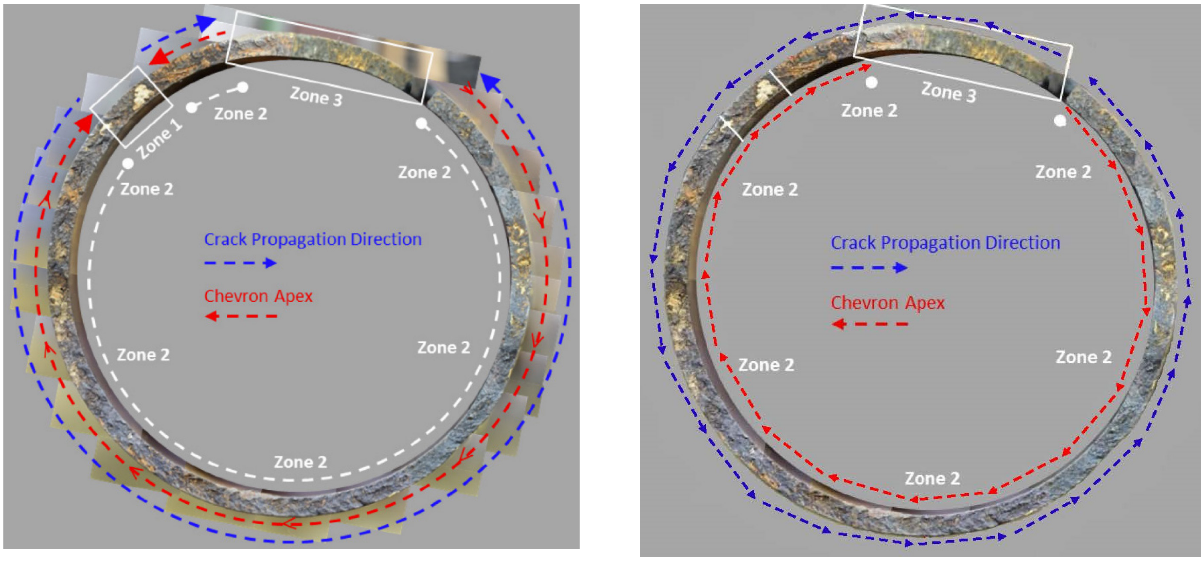


Figure 13. Left: Figure 69 from Blade main report. Right: Corrected Figure 69 showing actual crack growth direction.

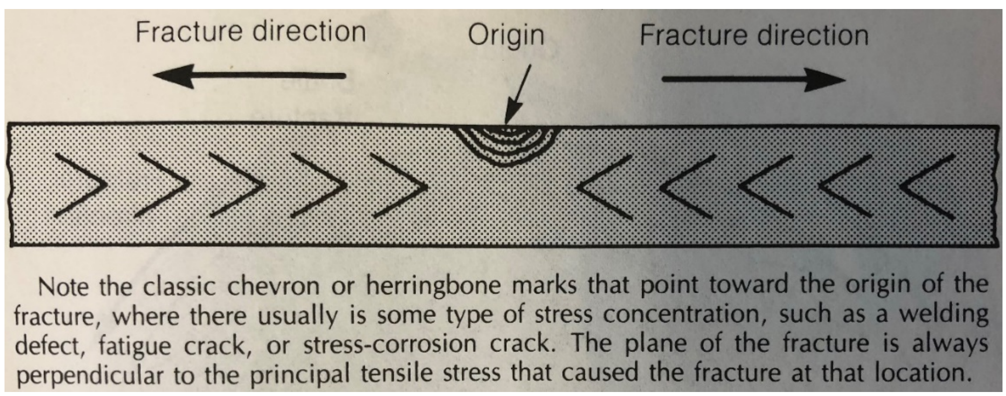


Figure 14. Illustration of chevron marks on a steel fracture surface.[75]

[75] Ex. II-38 (Wulpi, Donald J., Understanding How Components Fail, American Society for Metals, 1985, at 91).


Figure 15. Figure 68 from page 72 of Blade main report. Red rectangle encloses backward chevron marks drawn by Blade. Red chevron marks inserted above are consistent with chevron marks present on the fracture surface. Blade misidentifies the chevron marks as flowing towards the origin. Based on both my physical inspection on February 27-28, 2020, and my analysis of this image, the chevron marks travel to the right, as indicated by the red arrows at the bottom of the figure.

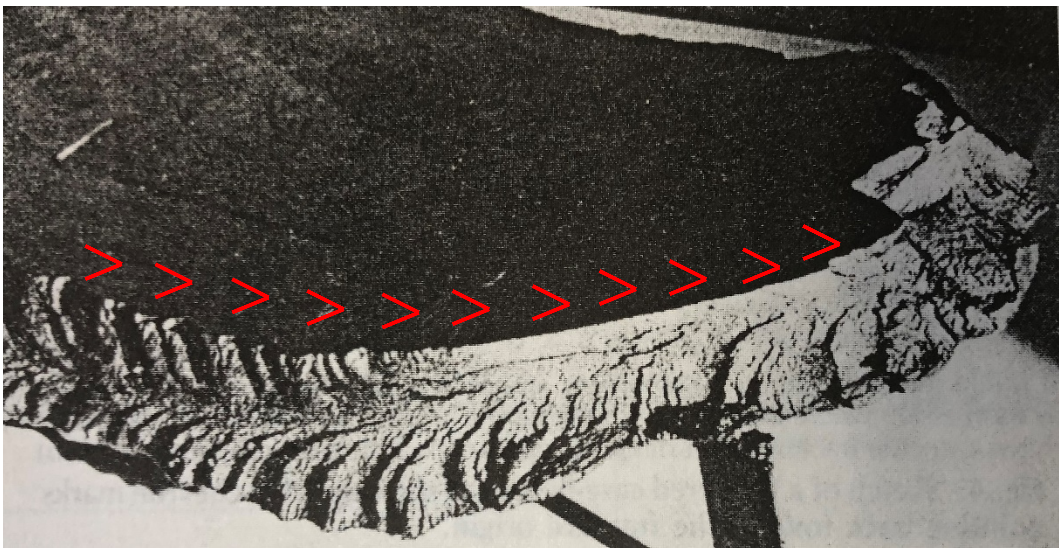

Figure 16. Fragment of a thick-walled fractured drum. The fracture, which started at the right, ran rapidly to the left, resulting in a well-defined chevron pattern.[76]

[76] Ex. II-38 (Wulpi, Donald J., Understanding How Components Fail, American Society for Metals, 1985, at 91).

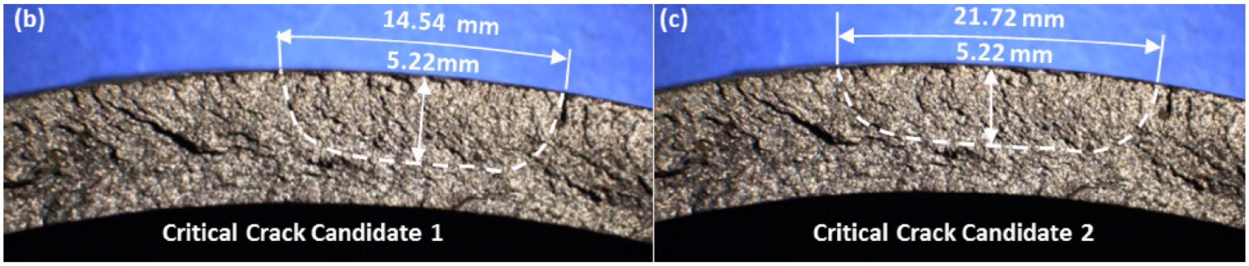


Figure 17. There are no features in either of the areas shown in Blade Figures 68b or 68c that suggest the existence of a fracture origin.

B. Surveys of SS-25 Did Not Identify Any Leaks Prior to October 23, 2015.

Margaret Felts testified that temperature and noise surveys of the SS-25 well showed one or more leaks from 1978 to 2012.[77] She further testified that a number of annual surveys documented a leak at the bottom shoe of the well.[78]

Neither statement is correct. SS-25 was not leaking prior to October 23, 2015. As Blade stated, "Numerous temperature, noise, and pressure surveys were run in SS-25 between the years of 1974 and 2014, and **no major anomalies were found** indicating fluid migration."[79] Indeed, SoCalGas performed at least 60 wireline temperature logs of SS-25 from March 14, 1974 through October 21, 2014 and **none of these logs** indicate any leak in the production casing (Figure 18).

Regarding the alleged shoe leaks, Ms. Felts is presumably referring to the cooling interval that is visible on many of the SS-25 temperature logs at a depth of approximately 8500 ft. That is the depth where SS-25 intersected the storage reservoir and where the production casing was perforated to allow gas to flow between the well and the reservoir. Gas cools significantly as it flows from the storage formation at high pressure into the well, which has a lower pressure. The gas then warms as it flows above the packer and into the production casing.

The following are additional important points:

- The cooling shown on the SS-25 temperature logs at this depth was not indicative of a leak. The movement of gas into or out of the storage zone always causes

[77] Ex. I-10 (Felts Depo. Tr. 169:2-170:1).
[78] *Id*. at 173:11-13.
[79] Blade Report at 198 (emphasis added).

localized cooling; indeed, cooling behavior where a storage well meets the reservoir has been well known for many years, as can be seen in Figure 19.[80]

- All storage wells at Aliso Canyon exhibit the same or similar cooling at that depth. For example, Figure 20 shows that Fernando Fee 32A and Porter 72A both exhibit cooling at the bottom of the wells, and the same is true for SS-25A and SS-25B (Figure 21).

- Some temperature surveys over the years reported possible slight leakage in the vicinity of the production casing shoe and noise logs were run following a number of these temperature surveys. SoCalGas performed noise logs in SS-25 on the following ten dates: September 8, 1978, December 11, 1978, August 8, 1979, November 24, 1981, February 23, 1983, April 11, 1984, July 27, 1984, November 7, 1991, November 7, 2006, and June 1, 2012. None of these noise logs indicate a gas leak in the production casing. None of these noise logs indicate a gas leak in the production casing or at the production casing shoe.

- A radioactive tracer survey performed on July 29, 1984 reported possible slight leakage behind pipe from top perf at 8510 ft up to around 8430 ft and 8190 ft. This survey indicates gas flowing up to the bottom of the cap rock at approximately 8182 ft and into the permeable S1 formation.

- The noise logs display four curves, representing sound at frequencies of 200 Hz, 600 Hz, 1,000 Hz, and 2,000 Hz, respectively. Low frequency noise (200 and 600 Hz) is usually indicative of surface noise or low rate flow of fluids behind casing. High frequency noise (1,000 and 2,000 Hz) is usually indicative of the flow of gas, bubbling of gas in liquids, or high-rate gas flow. The interpretation of noise logs is well-established: a sharply-defined, high-frequency noise over a short length of casing is an indication of a gas leak.[81] [82] [83]

- There are no such sharply-defined, high-frequency noises over short lengths of casing in the SS-25 noise logs that would indicate the presence of a gas leak. In some of the logs, there is a noticeable sharp peak in noise, but these were caused by the operators testing the noise logging tool prior to entering the completion equipment at or below 8,000 ft., and these operator tests are clearly labeled on the logs (see, e.g., November 24, 1981 log).

- SoCalGas performed the noise log of December 11, 1978 from 5,800 to 7,770 ft., and that log measured no anomalous noise. The logs of November 7, 2006 and

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[80] Ex. II-39 (Bird, J. M. (1954, January 1). Interpretation of Temperature Logs in Water- and Gas-injection Wells and Gas-producing wells. American Petroleum Institute).

[81] Ex. II-40 (Smith, B. A., & Neal, M. R. (1970, January). Evaluation of Gas Storage Well Completions with Well Logs. Society of Petroleum Engineers. doi:10.2118/2965-MS).

[82] Ex. II-41 (McKinley, R. M. (1994, July). Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity. Report No. EPA/600/R-94/I24 for Cooperative Agreement No. CR-818926.

[83] Ex. II-42 (McKinley, R. M., & Bower, F. M. (1979, November 1). Specialized Applications of Noise Logging). Society of Petroleum Engineers. doi:10.2118/6784-PA).

June 1, 2012 were performed for the entire length of the well and measured no anomalous noise.

- SoCalGas performed the remaining noise logs performed in 1978, 1979, 1981, 1984 (2 runs), and 1991 to assess potential leaks. All logs measured generally shallow low frequency noise (200 to 600 Hz). These low-frequency measurements are interpreted to originate from surface noise at the Aliso Canyon site or operations in nearby wells, which is common and described by McKinley [1995].[84] The 1978 log includes operator comments referencing surface noise.

- The same six logs also measured noise across all four frequency ranges slightly above the packer and completion equipment at the base of the well, and across the storage formation. Such noise is expected and is associated with movement of gas in the storage formation and through the completion equipment. The 1991 log includes operator comments regarding noise interpreted as "bubbling" at a depth of about 7,500 ft., which is shown in the excerpt of the log in Figure 22. As can be seen in the figure, the noise log was repeated over the depth range of 7,200 ft. to 7,600 ft. and the indicated bubbling noise was not detected.

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[84] *Ibid*. at 113 n. 29 ("The above comment raises the issue of the complicating influence of extraneous sources of noise, especially that due to surface machinery, on the quality of a noise survey. The failure to recognize such sources is characteristic of an inexperienced logging engineer.").

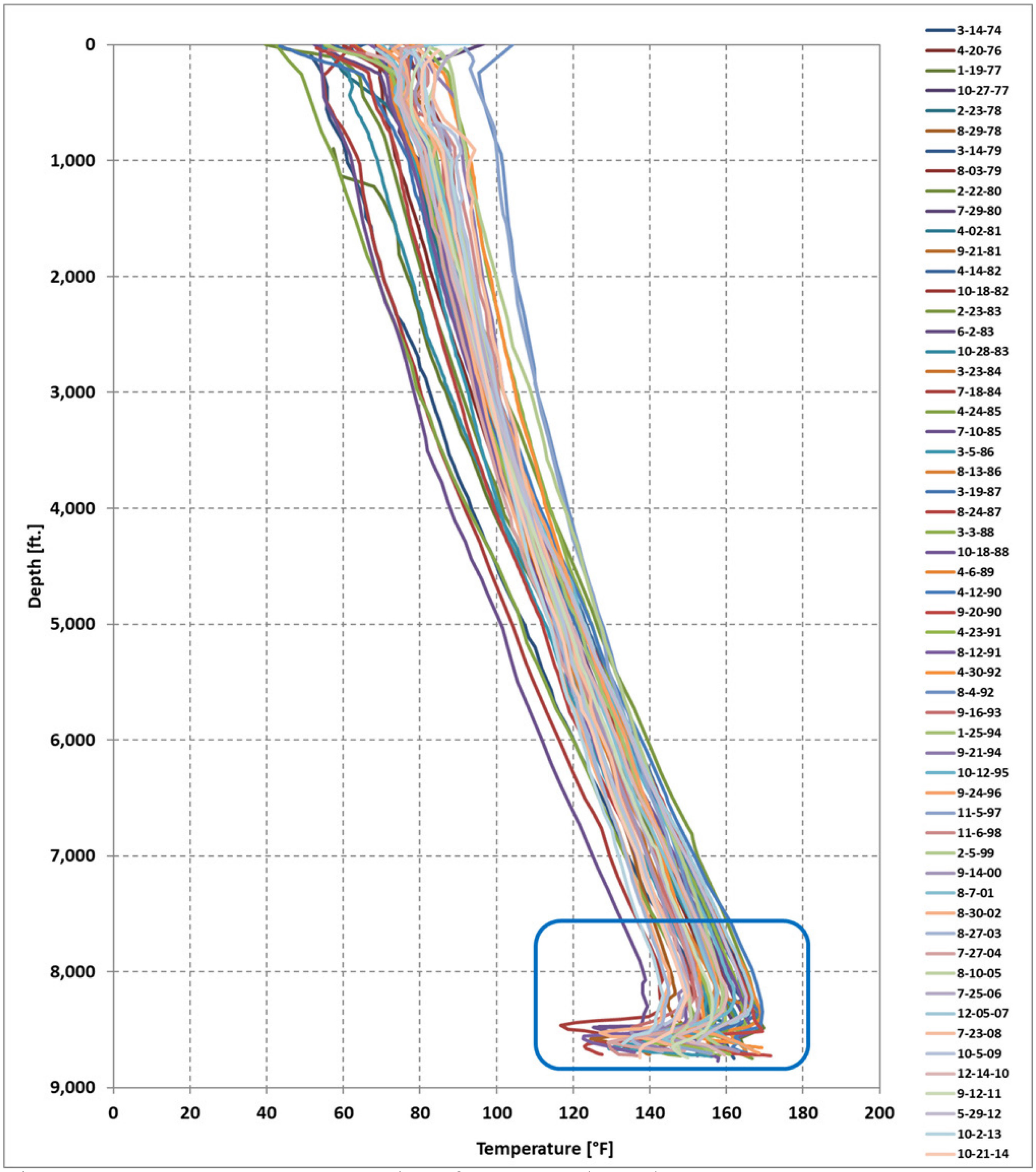

Figure 18. SS-25 temperature logs from 1974 through 2014.

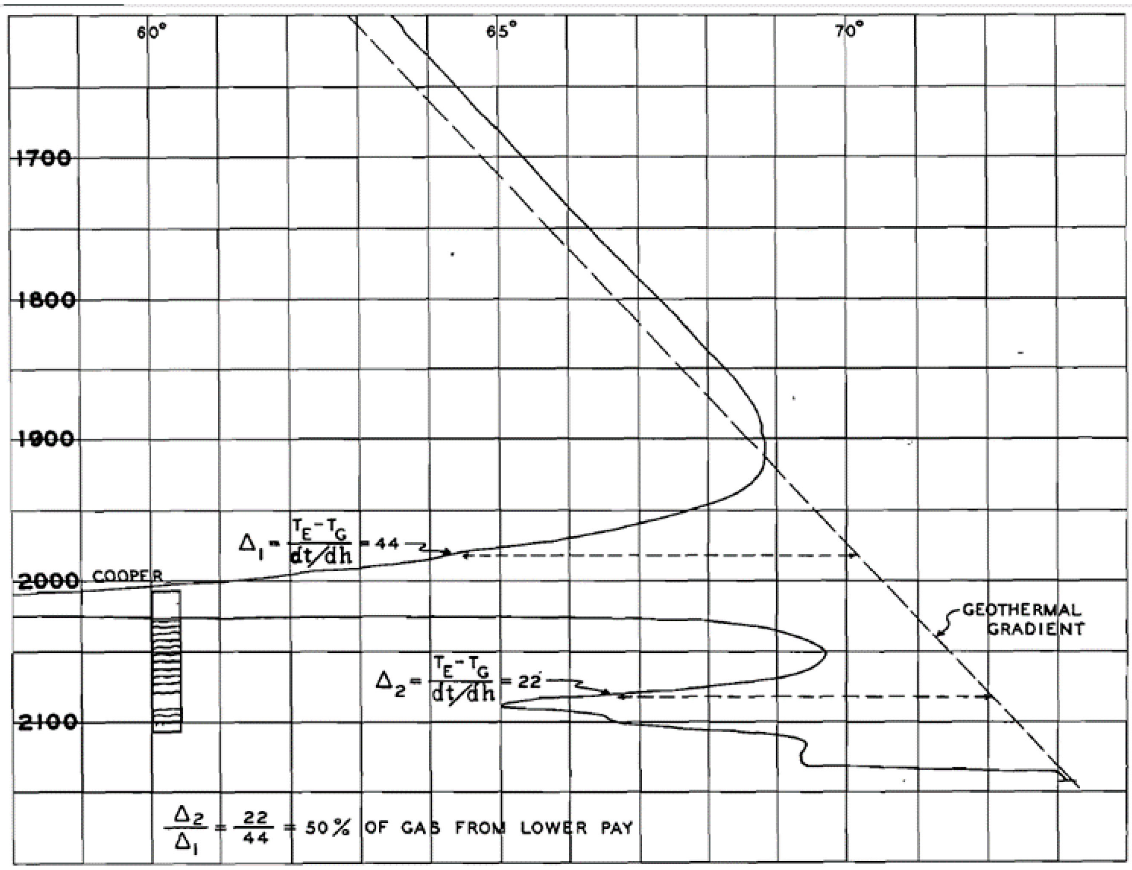


Figure 19. Gas well temperature log showing cooling at the packer and perforation (Bird, 1954).

**Fernando Fee 32A**
**30 December 1998**

**Porter 72A**
**25 September 2002**

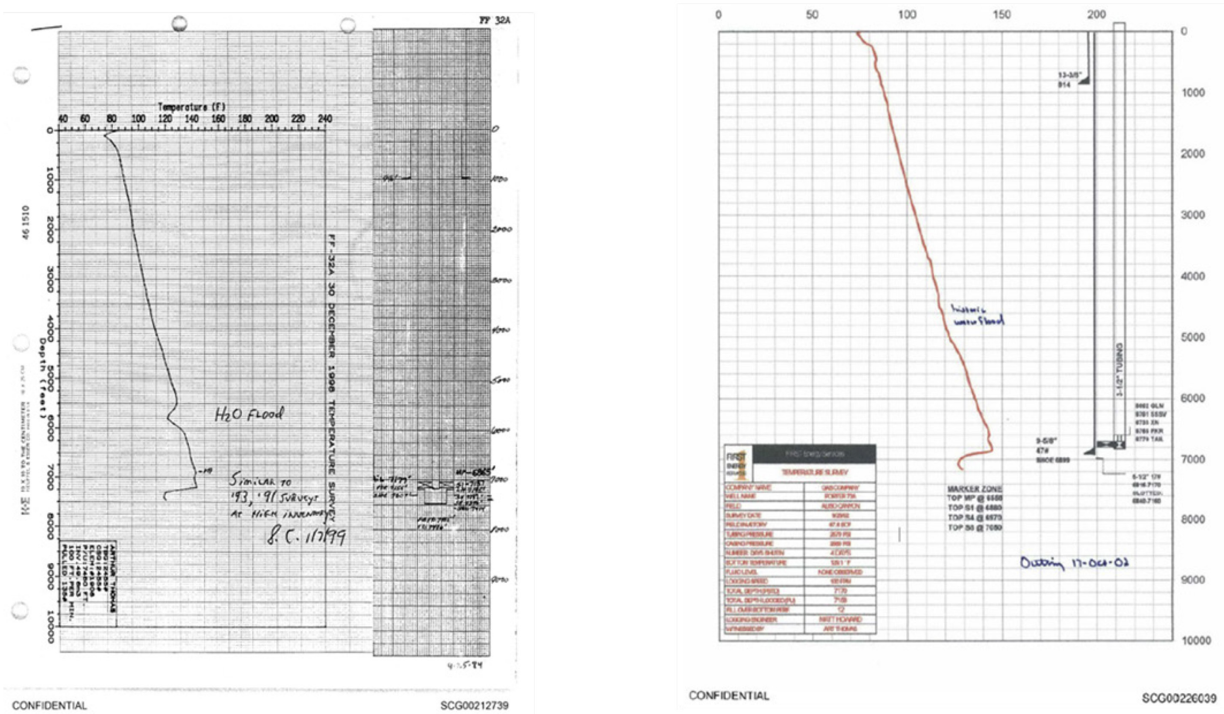


Figure 20. Temperature logs for Fernando Fee 32A (left) and Porter 72A (right).

SS-25 SS-25A SS-25B

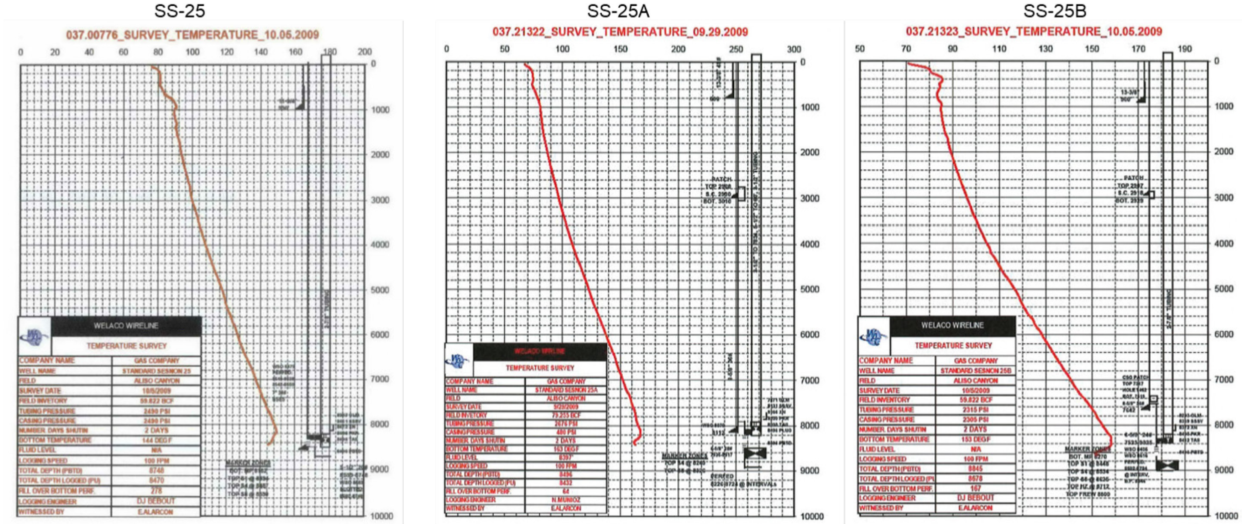


Figure 21. Temperature logs taken in 2009 in wells SS-25, SS-25A, and SS-25B.

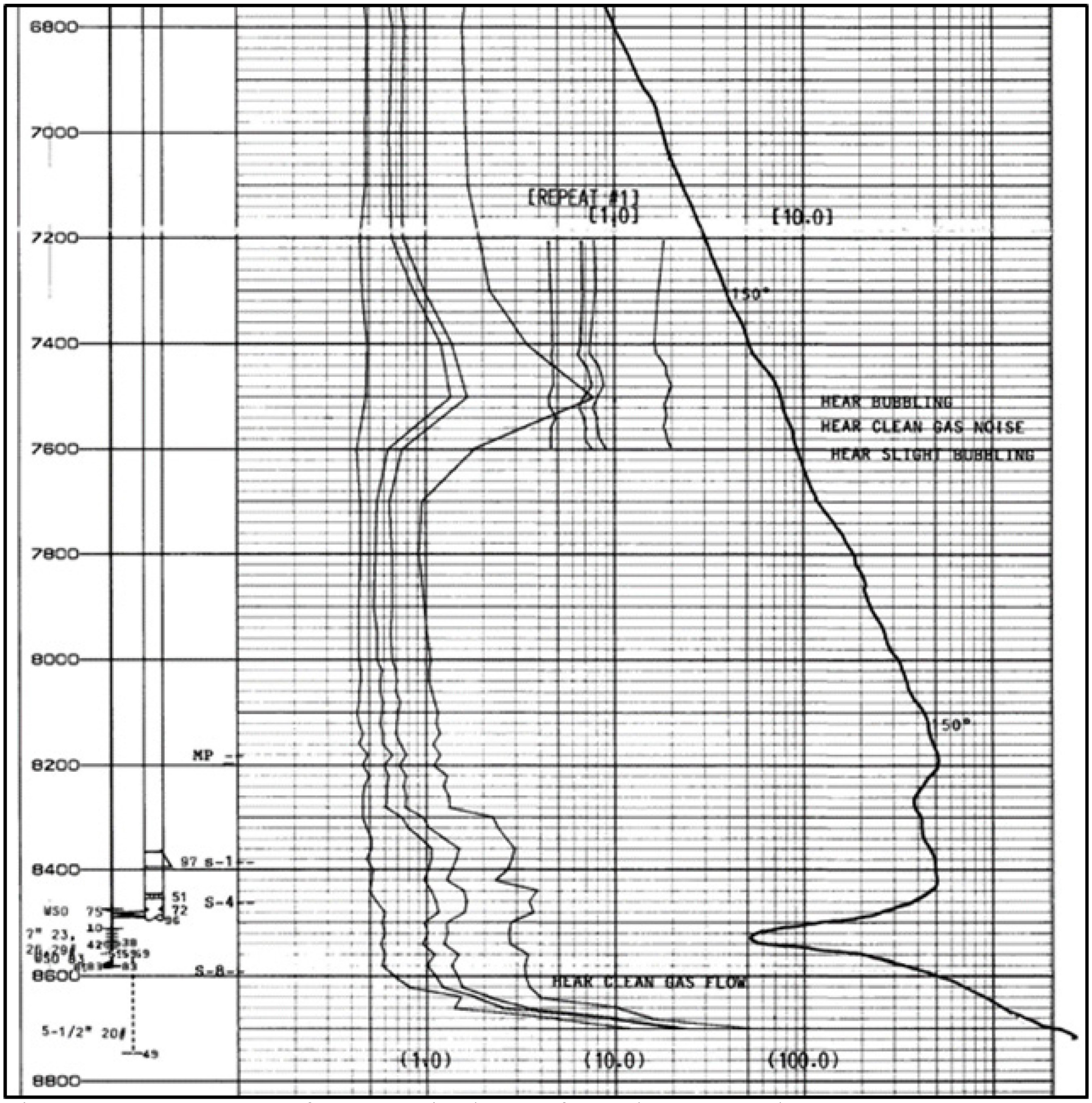

Figure 22. Excerpt of SS-25 noise log performed on November 11, 1991.

## VI. CONCLUSION.

SoCalGas acted reasonably and prudently in conducting well casing inspections, contrary to allegations of SED and PAO. PAO and SED both wrongfully accuse SoCalGas of failing to act prudently regarding well casing inspections. PAO's and SED's arguments that various inspection methods either revealed, should have revealed, or could have prevented the leak at SS-25 have no basis. Based on my knowledge, experience, and expertise, SoCalGas took reasonable and prudent steps to monitor and inspect the integrity of its wells at Aliso Canyon, including by conducting casing log inspections and temperature and noise surveys.

## WITNESS QUALIFICATIONS

My name is Robert A. Carnahan. My business address is Exponent, Inc. 5401 McConnell Avenue, Los Angeles, California 90066.

**Credentials and Qualifications**

1. I am a Principal Engineer at Exponent, Inc. ("Exponent"). I hold an M.S. degree in Metallurgical Engineering from the University of Michigan. I hold a B.S. degree in Materials and Metallurgical Engineering, also from the University of Michigan. I am a licensed Professional Mechanical Engineer in the states of Arizona, California, Michigan, Nevada, Texas, and Utah. My qualifications are described in greater detail below and summarized in my curriculum vitae, attached as Exhibit 1.

2. I am certified by the American Petroleum Institute (API) as a corrosion and materials professional (API 571).

3. I have expertise in physical metallurgy, materials selection, failure analysis and prevention, fracture mechanics, corrosion, including microbiological influenced corrosion, welding, engineering mechanics, and machine design.

4. From 1980 through 1986, I was employed in the Nuclear Energy Division of General Electric Company in San Jose, California. While at General Electric Company, I performed research on stress corrosion cracking of stainless steels and nickel base alloys. I installed an in-situ stress corrosion cracking test at an operating nuclear power plant, which utilized the DC potential drop method to monitor crack growth. I visited numerous nuclear power plants in the United States and abroad to investigate cracks in stainless steel piping and other types of failures. I performed laboratory failure analysis of a variety of components from operating nuclear power plants. During my career at General Electric, I developed special expertise in many areas of metallurgical engineering and corrosion, which are areas at issue in this arbitration.

5. While at General Electric, I was admitted to the Materials Science and Engineering department at Stanford University and took the core courses required for a Ph.D.

6. From 1987 through most of 1988, I was employed in the Aerospace Division of General Electric and worked on a space nuclear power project known as SP-100. For the SP-100 project, I investigated creep-rupture behavior of niobium alloy fuel cladding, compatibility of niobium structural alloys with liquid lithium, neutron irradiation resistance of carbon-carbon composites, and bearing materials for use in an aggressive elevated temperature, high vacuum, high neutron flux environment.

7. In 1988, I was hired by Failure Analysis Associates, Inc. (now Exponent) in Palo Alto, California (and now Los Angeles), where I have developed a consulting practice in the areas of metallurgical, corrosion, and mechanical engineering. With specific focus on oil and gas industry projects, I have performed failure analysis of a variety components, including pipelines, heat exchangers in hydrogen service, cryogenic brazed aluminum plate-fin heat exchangers, piping in HF alkylation units, and pumps in flammable service.

8. I have not previously testified before the Commission.