# SoCalGas-70

# Blade Energy Partners' Response to SED Data Request-58

# I.19-06-016

# ALJs: Hecht/Poirier

# Date Served: March 15, 2021

# Response to Data Request

# Response to SED Data Request-58

## Prepared for:

**Mr. Darryl Gruen**
**CPUC Legal Division**

## Purpose:

Blade response to the CPUC Data Request SED 58 related to Vertilog technology and the casing failure in SS-25 from Reply Testimony of Mr. Robert Carnahan on behalf of SoCalGas.

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# Version Record

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# Version History

| Version | Date | Description of Change |
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# 1 Background

The Legal Division of the California Public Utilities Commission issued a Data Request to Blade Energy Partners (Blade) on March 30, 2020. Data Request No: SED 58 related the Preliminary Investigation of Southern California Gas Company's Aliso Canyon Storage Facility.

The CPUC statements (from file: "I1906016 SED DR 58 Final.pdf") are included verbatim followed by the Blade answers to the questions.

The page numbers and figure numbers in the verbatim statements refer to a document titled: Chapter II, Prepared Reply Testimony of Robert A. Carnahan, P.E. on behalf of Southern California Gas Company (U 904 G). File name: "2_Ch. II - Exponent - Carnahan (A Final).pdf".

# 2 Statements and Responses

## 2.1 Statement 1

Pages 1 and 2: "[Public Advocates Office's] allegations presuppose that the Vertilog technology at that time [1988] was reliable and accurate. That is not the case."

### 2.1.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   The Vertilog or equivalent technology that existed in 1988 was capable of detecting and discriminating metal loss features, with only its sizing and characterization capabilities being limited compared to the current technology. That being said, it was the best technology available at the time for monitoring metal loss in casing and was sufficient to indicate the presence of corrosion issues.

   Mr. Carnahan incorrectly references a quote [page 2, line 12] found in a Pipeline & Gas Journal article (footnote #9). The original quote, which is related to pipeline inspection, is being misapplied to downhole logging. The complete quote is:

   > "Historically, the results of the first-generation MFL tools were not very satisfactory, but BG (British Gas) and then PII developed advanced electronics and analysis algorithms and software which set new standards in the industry."

   In Mr. Carnahan's testimony [at page 2, line 12, and page 8, line 13], he modifies the quote as follows:

   > "Historically, however, the results of the first generation of MFL tools were not very satisfactory.[9]"

   The original quotation notes the advances in technology but were not acknowledged by Mr. Carnahan. The statement by Goedecke, the original author, about first-generation magnetic flux leakage (MFL) tools and subsequent advances in technology was in reference to pipeline inspection tools. These first-generation MFL tools were developed from approximately 1959–1965 [1, 2, 3]. The first commercial effort to collect information using MFL tools was by AMF Tuboscope in 1965; the name of the tool was the Linalog [1, 2, 3]. By 1983, 112,000 km of pipeline had been inspected [4]. Mr. Carnahan mischaracterizes the Vertilog as a first-generation MFL tool but there were significant advances in MFL technology that began in the pipeline industry [2] prior to the Vertilog's deployment into oil and gas wells in the mid 1970's.

   Mr. Carnahan negatively portrays the Vertilog [page 2, line 8], "... as a mechanism that attempts to utilize Magnetic Flux Leakage (MFL) to detect casing metal loss[8]." The footnote #8 that Mr. Carnahan refers to was a 1977 Society of Petroleum (SPE) paper [5] written by employees of the logging company Dresser Atlas, which would later become part of Baker Hughes. The word *"attempts"* is not used in the reference. Although Mr. Carnahan describes the working principles of the Vertilog, he fails to provide the context that MFL and eddy current technology for the use of corrosion inspection were well established in oil and gas pipeline operations. The SPE paper's authors describe the Vertilog tool as follows:

It is a quantitative measurement of corrosive damage, indicating if the metal loss is internal or external, and if it is isolated or circumferential. Holes in the casing can be identified as well as parted casing. This survey in conjunction with other measurements, can be used to detect, monitor, and establish preventive techniques for corrosive problems.

Figure 1 shows the Vertilog and Digital Vertilog (DVRT) performance specifications as of 1991 (provided by Mr. Rod Foster, Well Integrity Senior Advisor, Baker Hughes). The two tools are essentially the same tool and sensor system but the DVRT has upgraded electronics for improved acquisition and computerized processing [6]. The DVRT was deployed in approximately 1991, superseding the Vertilog. As a point of reference, the DVRT was considered by Blade[i] for use in logging of the 11 3/4 in. surface casing as part of the SS-25 RCA. Considering the wall thickness of 0.317 in. (for 7 in. 23 ppf production casing in SS-25), the Vertilog and DVRT could detect defects deeper than 30% or 0.095 in. and size them +/- 15% or 0.048 in. For the Vertilog and DVRT, a 50% deep defect could be sized between 35–65%. In comparison, the High Resolution Vertilog (HRVRT) can detect defects that are deeper than 15% or 0.048 in. and size them +/- 10% or 0.032 in. For the HRVRT, a 50% deep defect could be sized between 40-60%.

| | |
|---|---|
| **Measurement Range:** | 30 to 90% penetration of the casing wall in single string |
| **Absolute Accuracy:** | ±15% of actual pit depth in single string casing for isolated pitting, when casing information such as weight, grade, etc. is available |
| **Repeatability:** | ±10% of first reading if pipe was fully magnetized on first pass |
| **Sensitivity:** | Casing defects as small as 0.375 in. (9.5 mm) in diameter with as little as 30% penetration can be detected and recorded at 100 ft/min (30.5 m/min) in single string |
| **Radial Investigation:** | Tool is designed to inspect the full casing circumference |
| **Depth of Investigation:** | 100% of the wall of the inside casing |

**Figure 1: Performance Specifications for the Vertilog, and Digital Vertilog from 1991**

Table 1 shows a listing of casing inspection logs that were downloaded from the DOGGR website [7] during the course of Blade's RCA; the logs are within 10 years of the proposed dates of the 1988 Interoffice Correspondence 2-year logging program [8]. As discussed in Blade's Main RCA report [9, p. 204], Blade's position is that SoCalGas made a recommendation to run the Vertilog in 20 wells that concerned them at the time. Blade reviewed the logs listed in the table that were run in approximately the same time frame as the 1988 Interoffice Correspondence. Although we did not perform an exhaustive study; in our opinion, the Vertilog was superior to the inspection tools of its day, specifically, the Welex Casing Inspection Log, McCullough Electronic Casing Caliper, and Schlumberger Electromagnetic Thickness Log. The recommendation to run Vertilog casing inspections in 20 wells appeared to Blade to have been based on using the best available technology at that time for the purpose of assessing the mechanical condition of casing flow wells completed in the 1940s and 1950s.

[i] In 2016–2017, the DVRT was the was only MFL tool available to inspect the 11 3/4 in. casing. Although the sensor system was developed in the mid-1970's with upgraded electronics in approximately 1991, the DVRT was still in-service and was initially Blade's primary MFL logging option. Because it was important to attain the most accurate data, Blade requested that Baker Hughes and its vendor, Microline Technology Corporation, adapt the HRVRT to 11 3/4 in. casing size. The DVRT was not used in the SS-25 RCA.

Mr. Carnahan's assertion is that the Vertilog was unreliable and inaccurate and combined with other factors, would not have prevented the SS-25 incident. His basis for finding the Vertilog unreliable and inaccurate is derived from his numerical comparison of five (5) Vertilogs from 1988–1990 to various HRVRT and USIT logs run in 2013 and 2016–2018. This is an approach that would not have been available to SoCalGas in the late 1980s or early 1990s. Certainly, logging technology of 2010s would be expected to be more accurate than that of late 1980s and early 1990s. However, this does not mean that the older logging tools did not provide useful or actionable information.

For example, in 1989, researchers evaluated four types of casing inspection tools, stating the following [10]:

> Electromagnetic casing inspection logs are commonly used in the industry to survey the condition of casing. Logs may be used to estimate the amount of pitting, degree of corrosion, wall thinning, changes in diameter, and other casing features. Occasionally, casing inspection logs are used to investigate a casing failure in a well. Interpretations of casing inspection logs may be used to determine the type of remedial work on a well where a casing failure has occurred, or they may be an important factor in a commercial casing failure claim.

There are key concepts in this paper related to casing inspection tools available in 1989. The first was that casing inspection tools were commonly used for detecting pitting, degree of corrosion, and wall thinning. The second was the authors describe MFL technology, specifically mentioning the Vertilog, as capable of being able to distinguish between split and parted casing.

Two of the wells in Table 1 had underground blowouts, namely F-3 and FF-34A, which were logged in 1986 and 1991 respectively. These dates bookend the Vertilog logging campaign outlined in the 1988 Interoffice Correspondence. Note that the Schlumberger Ultrasonic Imager (USIT) was run in P-42B in 1993, which was not that long after the September 10, 1990 FF-34A casing failure and when the Vertilog logging campaign was discontinued.

**Table 1: Aliso Canyon Casing Inspection Logs within 10 years of 1988–1990**

| Well | Date | Vendor | Log Name |
|---|---|---|---|
| FF-35B | August 31, 1978 | McCullough | Electronic Casing Caliper |
| SS-1 | February 27, 1980 | McCullough | Electronic Casing Caliper |
| MA-1A | February 28, 1985 | McCullough | Electronic Casing Caliper |
| F-3 [b] | January 31, 1986 | Welex | Casing Inspection Log |
| F-4 [a c] | September 6, 1988 | Western Atlas | Vertilog |
| P-37 [a] | October 11, 1988 | Western Atlas | Vertilog |
| P-46 [a, c] | October 19, 1988 | Western Atlas | Vertilog |
| SS-9 [a, c] | December 16, 1988 | Western Atlas | Vertilog |
| SS-8 [a, c] | January 17, 1989 | Western Atlas | Vertilog |
| P-32C | July 26, 1989 | Western Atlas | Vertilog |
| P-34 [a, d] | November 2, 1989 | Western Atlas | Vertilog |
| FF-35B [c, d] | November 11, 1989 | Western Atlas | Vertilog |
| MA-1A | December 27, 1989 | Western Atlas | Vertilog |
| F-2 [a, d] | January 11, 1990 | Western Atlas | Vertilog |

| Well | Date | Vendor | Log Name |
|---|---|---|---|
| FF-35C | September 18, 1990 | Western Atlas | Vertilog |
| SS-14 | March 5, 1991 | Halliburton | Casing Inspection Log |
| FF-34A [b] | May 11, 1991 | Schlumberger | Electromagnetic Thickness Log |
| P-42B | January 11, 1993 | Schlumberger | Ultrasonic Imaging Tool |
| P-68B | May 27, 1993 | Halliburton | Casing Inspection Log |
| SS-14 | May 26, 1998 | Halliburton | Casing Inspection Log |
| SF-2 | November 19, 1999 | Schlumberger | Ultrasonic Imaging Tool |

[a] – Wells listed in the 1988 Memo (F-4, P-37, P-46, SS-9, SS-8, P-34, F-2)
[b] – Wells that had blowouts (F-3, FF-34A)
[c] – Wells reviewed by Mr. Carnahan (F-4, P-46, SS-9, SS-8, FF-35B)
[d] – Logs not available on the DOGGR website (P-34, FF-35B, F-2)

Mr. Carnahan's spreadsheet analysis neglects important findings that are visible graphically on the log. There is considerable information that can be derived from looking at the log image. Different logs employ different technology; the characterization and sizing of features may appear different. Most logging companies have some version of the cement bond log with variable density (CBL – VDL) for the determination of zonal isolation (i.e., to evaluate if the cement is an effective barrier). Although these logs have been utilized for over 50 years, the best way to interpret the presence of cement and the bond to pipe and formation is to *look* at the log. There are wavy, chevron, zigzag, and other patterns that have meaning. This is the same for the Vertilog and other casing inspection logs. There is data in the patterns.

Blade performed an analysis of F-4's 1988 Vertilog as part of the RCA [11] comparing it to the 2016 Ultrasonic Imager (USIT) log. Figure 2 shows these two logs with the Vertilog on the left and USIT on the right. To aid in interpretation from joint to joint, the logs have been adjusted so that the casing connections of each log are aligned. External metal loss is denoted by blue text at A, B, and C on the Vertilog's Flux Leak track, and by the same letter on the USIT's wall thickness track. At A-A, external metal loss is found just above a connection. At B-B, external metal loss is found approximately midway in the joint. At C-C, there is external metal loss below a connection. The point here is the two logs found the same defects.

There was good agreement between the logs at most depths. However, in some cases, the logs did not agree. It should not be assumed that the 2016 USIT log was the more accurate one. In Blade's experience, MFL tools are better at detecting pitting corrosion. In general, it's a flawed concept to compare one log tool to another and automatically claim one is more accurate than the other. Log data has to be compared to truth data (direct measurements of defects) to assess log performance. In today's era, repeatability and reproducibility of pipeline inspection tools are verified independently in pull-through tests (e.g., Pipeline Research Council International Integrity and Inspection projects). Even today, very little data has been published in testing downhole logging tools in controlled environments. An independent comparison of casing inspection logging tools spanning decades does not exist, however, the Vertilog and other casing inspection tools could have been used as an indicator of an issue.

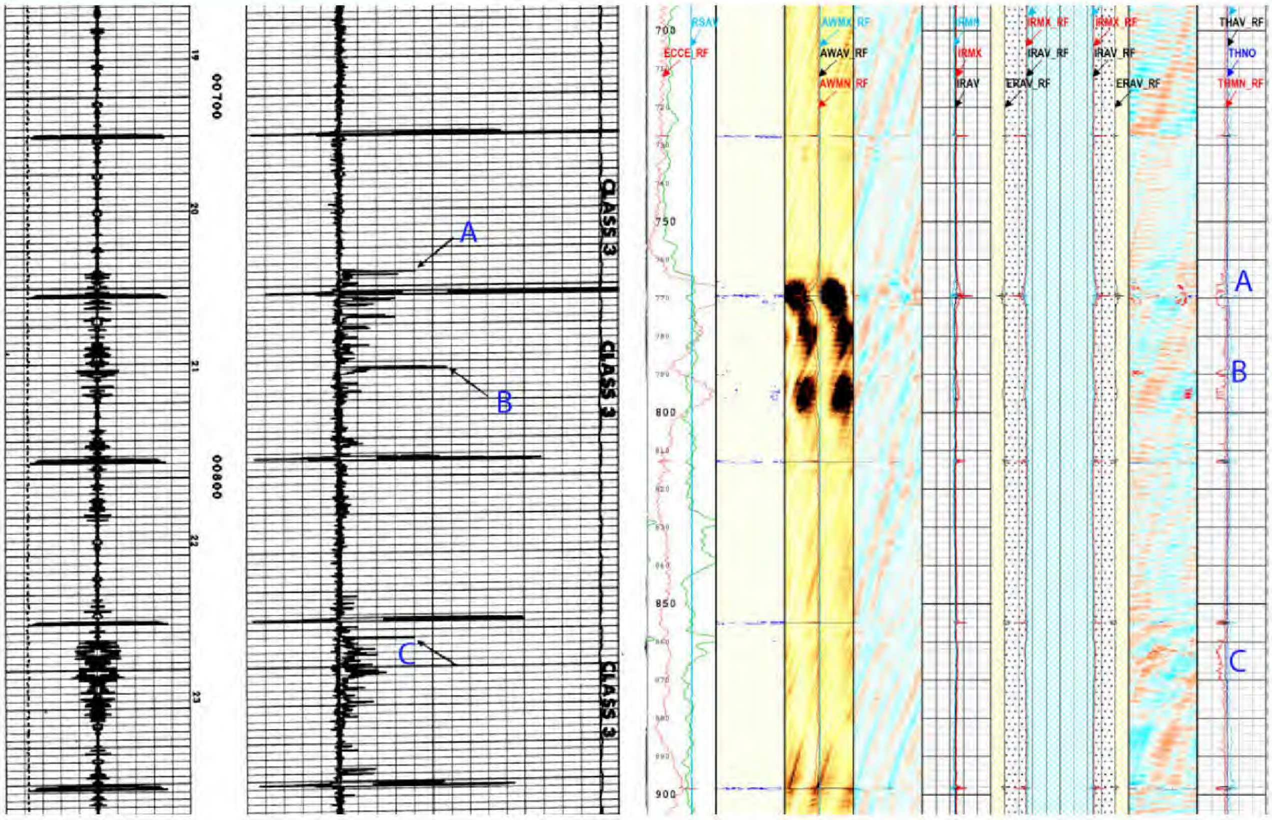


**Figure 2: F-4 1988 Vertilog (Left) and 2016 USIT (Right) Comparison**

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   SoCalGas had a two-year plan in 1988 to determine the mechanical condition of the casing in 20 wells originally completed in the 1940s and 1950s. Blade reviewed the records of all 20 wells to evaluate subsequent casing inspections and the casing problems that occurred in the following years. A number of casing problems were identified. SoCalGas made a recommendation to run casing inspection logs in 20 wells that concerned them at the time, and the opportunity to inspect the casing in SS-25 was missed. There is no way to know what an inspection of the SS-25 casing would have shown in 1988, but it is possible that corrosion was present and detectable, and steps could have been taken to avoid the leak in 2015 [9, pp. 2, 160, 173–181, 204-205] [12].

   The fact is that SS-25 and other 1988 Interoffice Correspondence wells did not get inspected according to plan.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Even if Blade accepted Mr. Carnahan's statement as true, it would not change any of the conclusions Blade reached in its Root Cause Analysis.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not Applicable. No conclusion changes are needed.

## 2.2 Statement 2

Pages 3 and 4: "While useful to a certain extent, the Vertilog technology circa 1988 suffered from certain substantial deficiencies."

### 2.2.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   The Vertilog circa 1988 was useful because it could be used to assess casing integrity in terms of the location and severity of metal loss.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   See the response to Statement 1, Question 3.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Mr. Carnahan's statement does not change the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.3 Statement 3

Page 4: "For example, the Vertilog technology did not provide a method for differentiating isolated pitting from general corrosion."

### 2.3.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   The Vertilog was capable of differentiating general corrosion from isolated pitting. The methodology is discussed in a previously referenced SPE paper [5]. Figure 3 shows the F-4 Vertilog Defect Report. Isolated pitting is denoted by IP and general corrosion is denoted by GC.

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| | |
|---|---|
| CUSTOMER | SOUTHERN CALIFORNIA GAS COMPANY |
| PAGE ___ OF ___ | |
| LEASE/WELL NO. | FREW No. 4 |
| WORK ORDER NO. | 124201 |
| DATE | 9-6-88 |
| FIELD | ALISO CANYON |
| CUSTOMER ORDER NO. | |
| CASING O.D. | 7" |
| WEIGHT(S) | 23#, 26# |
| COUNTY | LOS ANGELES |
| STATE | CALIFORNIA |
| TOTAL FOOTAGE INSPECTED | 8180' |
| NOMINAL WALL THICKNESS | |
| GRADE | N-80, J-55 |
| DEPTH FROM | SURFACE |
| DEPTH TO | 8180' |

SUBSURFACE CASING DEFECT REPORT

LENGTH NO. TYPE DEFECT PENETRATION LENGTH NO. TYPE DEFECT
INSIDE 13-3/8" CASING
7 OD IP

| LENGTH NO. | TYPE DEFECT | PENETRATION | LENGTH NO. | TYPE DEFECT | PENETRATION |
|---|---|---|---|---|---|
| INSIDE 13-3/8" | CASING | | 111 | OD IP | 41 - 60 |
| 7 | OD IP | 21 - 40 | 113 | OD IP | 41 - 60 |
| 13 | OD IP | 21 - 40 | 114 | OD IP | 41 - 60 |
| 20 | OD IP | 41 - 60 | | | |
| 21 | OD IP | 41 - 60 | | | |
| OUTSIDE 13-3/8" | CASING | | | | |
| 23 | OD IP | 41 - 60 | | | |
| 25 | OD IP | 21 - 40 | | | |
| 26 | OD IP | 21 - 40 | | | |
| 27 | OD IP | 41 - 60 | | | |
| 28 | OD IP | 41 - 60 | | | |
| 29 | OD GC | 21 - 40 | | | |
| 30 | OD IP | 21 - 40 | | | |
| 31 | OD IP | 21 - 40 | | | |
| 32 | OD IP | 41 - 60 | | | |
| 47 | OD IP | 21 - 40 | | | |
| 49 | OD IP | 21 - 40 | | | |
| 56 | OD IP | 21 - 40 | | | |
| 61 | OD IP | 21 - 40 | | | |
| 72 | OD IP | 61 - 80 | | | |
| 83 | OD IP | 21 - 40 | | | |
| 106 | OD IP | 41 - 60 | | | |
| 107 | OD IP | 41 - 60 | | | |
| 108 | OD IP | 41 - 60 | | | |
| 109 | OD IP | 61 - 80 | | | |

ABBREVIATIONS:
O.D. – OUTSIDE DIAMETER
I.D. – INSIDE DIAMETER
I.S. – INSIDE SURFACE PIPE
T.L. – THROUGHOUT LENGTH
I.P. – ISOLATED PITTING
C.C. – CIRCUMFERENTIAL CORROSION
G.C. - GENERAL CORROSION

**Figure 3: F-4 Vertilog Defect Summary Report, GC – General Corrosion and IP Isolated Pitting**

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

    See the response to Statement 1, Question 3.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

    No.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

    Not applicable. No conclusion changes are needed.

## 2.4 Statement 4

Page 5: "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."

### 2.4.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Casing inspection logs of all types can be processed and analyzed using different criteria and assumptions. There is inherent uncertainty in interpreting all casing inspection logs. The process is not automated with only one set of answers. Log analysts use their best judgement to provide most probable interpretations. See below for standard verbiage for casing inspection logs from Baker Hughes:

   FF-32A, HR Vertilog, 2016

   | |
   |---|
   | In making interpretations of logs our employees will give customer the benefit of their best judgment. But since all interpretations are opinions based on inferences from electrical or other measurements, we cannot, and we do not guarantee the accuracy or correctness of any interpretation. We shall not be liable or responsible for any loss, cost, damages, or expenses whatsoever incurred or sustained by the customer resulting from any interpretation made by any of our employees. |

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   See the response to Statement 1, Question 3.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.5 Statement 5

Page 7: "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."

### 2.5.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Blade would agree that the tool will have difficulty interpreting corrosion above, but not below, the shoe.

   Blade agrees with "...flaws of Vertilog were its inability to distinguish between defects and hardware (such as centralizers and scratchers)...". However, there is a key omission in Mr. Carnahan's testimony regarding the method in which the tool designers had envisioned solving this issue. References [5, 6] describe the use of accurate casing records to address the interpretation of centralizers and scratchers. The quote from [6, p. 1] below explains this issue clearly:

   > In the earlier Vertilog survey, casing hardware (e.g., scratchers and centralizers) caused responses which are similar to corrosive defect responses. Often casing records must be relied upon for identifying the log responses due to scratchers and centralizers, to insure [sic] that these responses

are not misinterpreted as casing defects. If the records are accurate, casing hardware responses are not mistakenly interpreted as defects. If the records are inaccurate, casing hardware responses can be interpreted as corrosive defects.

During the course of Blade's Analysis of Aliso Canyon Wells with Casing Failures study, numerous well records were analyzed. In our opinion, many of the well records that SoCalGas inherited from previous operators did not include an accurate location for centralizers and scratchers. Blade also reviewed hundreds of casing inspection logs from Aliso Canyon. It was common for the production casing string (e.g., 7 in., or 8 5/8 in. casings) to include a few joints of casing that were a different weight than reported. In other words, in the 200 or so joints that comprise the production casing string, it was likely that an occasional joint of thicker or thinner walled casing was run in the wrong position. This may not have any bearing on the casing string's pressure capacity. Inaccurate records on centralizers, scratchers, and casing weight and dimensions could result in Vertilog defect misinterpretation.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   In Blade's opinion, the Vertilog may overstate metal loss in multi-string casing configurations where an outer casing exists over part of the casing being inspected; this is discussed in the *Aliso Canyon Shallow Corrosion Analysis* supplementary report [11, p. 34].

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.6 Statement 6

Page 20: "Pressure testing is intended to detect existing casing leaks, not wall loss."

### 2.6.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No conclusion changes are needed.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

Not applicable. No conclusion changes are needed.

## 2.7 Statement 7

Pages 24-25, which states:

The Blade main report and various supplementary 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:

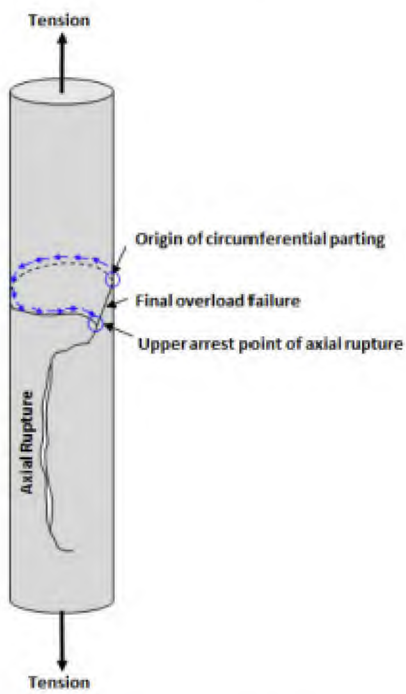



Figure 12. Left: Figure 70 from page 73 of Blade main report. Right: Corrected Figure 70 with red arrows added, which in addition to existing blue arrows, show actual crack propagation direction. The upper vertical fracture did not arrest abruptly at the location indicated by Blade. The circumferential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

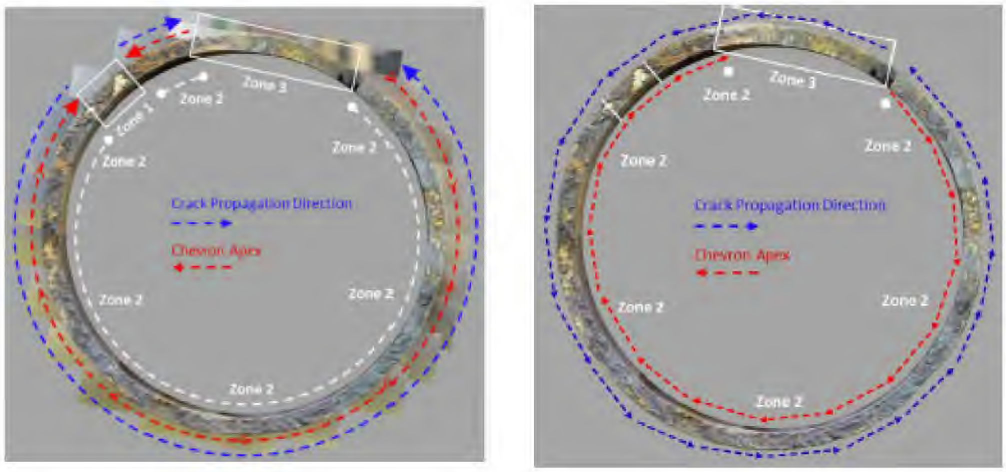



Figure 13. Left: Figure 69 from Blade main report. Right: Corrected Figure 69 showing actual crack growth direction.

## 2.7.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Mr. Carnahan's statement does not take into consideration all of the facts provided in Blade's Main and supplementary reports. Central to the argument are two facts. First, there are arrest turning points on both ends of the axial rupture. Second, there is no continuity of chevron marks from the axial rupture to the circumferential parting. This is further discussed in detail below.

   On page 54 in Section 2.4 of Blade's Main Report [9], it clearly states: "Visual and stereoscopic examination of the circumferential parting showed that the failure was not a continuation of the axial rupture, but rather re-initiated near the corner on one side of the parted casing. The origin site was determined based on chevron marks identified on the fracture surface. Figure 47 is a (a) laser scan and (b) image which identifies the upper arrest point, circumferential parting initiation site, and the final overload failure. Figure 48 is stitched stereo images showing the chevron marks and propagation direction of the circumferential parting. These observations indicate that the axial rupture and circumferential parting were two separate events despite their close proximity, and that they are most likely related to each other. This is discussed in more detail later within this section." Figures 47 and 48 are extracted from the Blade Main Report.

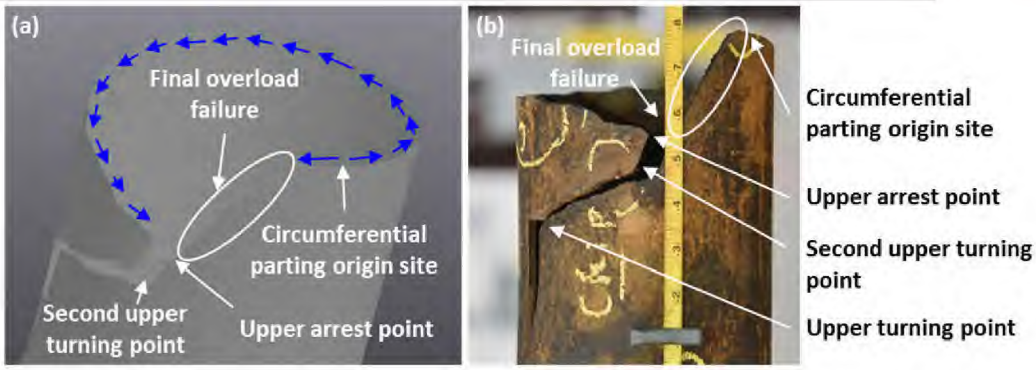



**Figure 47: (a) Laser Scan and (b) Photo Indicating Circumferential Parting Initiation Site and Final Failure**

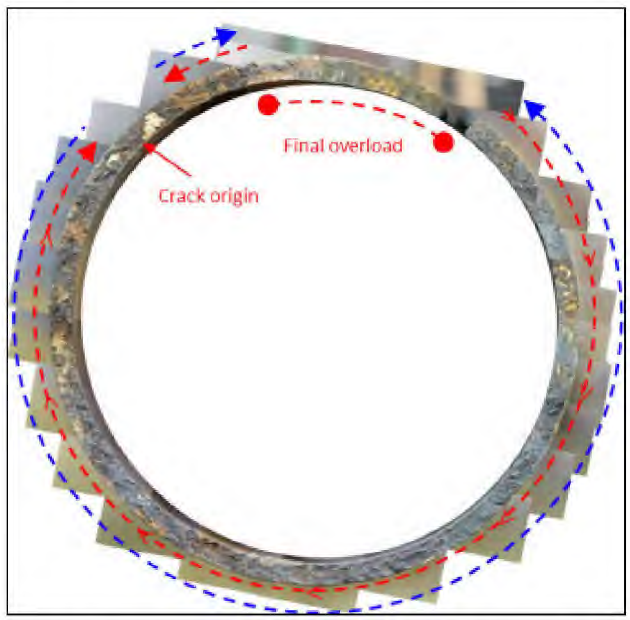



**Figure 48: Stitched Images of the Lower Circumferential Parting Fracture Surface**

Additional evidence is provided by Blade (Figure 67 on page 71 of Blade's Main report) illustrates the three zones of the circumferential parting. Figure 67 (a) is a stereo image showing the three zones, origin, and the direction of the crack propagation. Figure 67 (b) is a 3D schematic showing the overall circumferential parting steps. Figure 67 (c) is a close-up of the Zone 3 fracture surface, which does not exhibit any chevron marks, thus there is no continuity of the axial fracture.

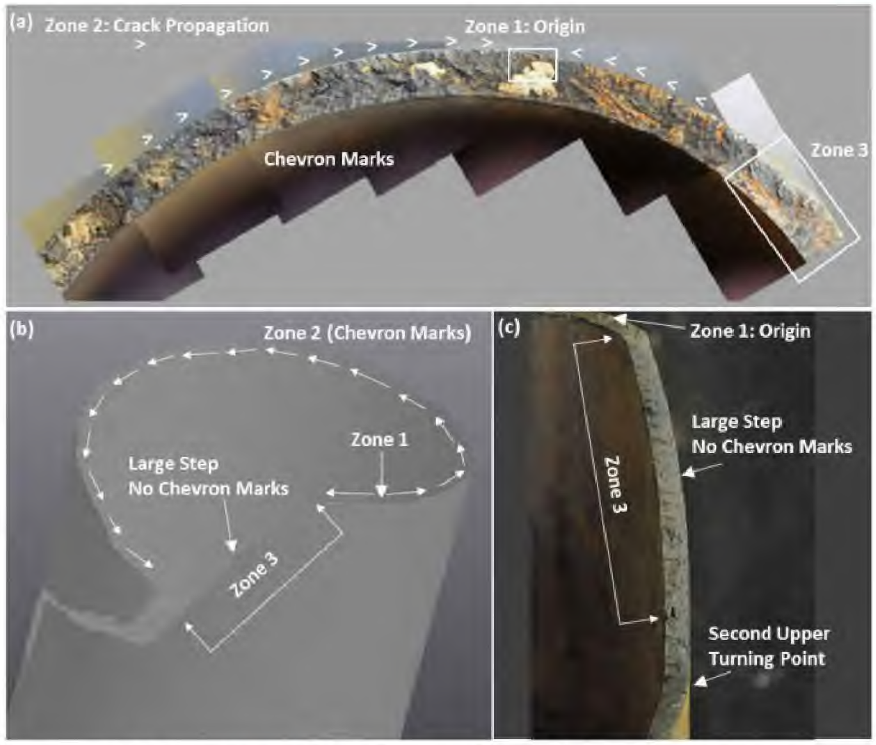



Figure 67: (a) Stereo Image (b) 3D Schematic of Zones (c) Macro Image of Three Zones

Based on the factual evidence shown above (pages 72 and 73 in Blade's Main report), Blade concluded "Additional detailed visual and stereoscopic examination showed that the circumferential parting was not an extension of the axial rupture. Chevron marks produced by the circumferential parting did not follow the chevron marks produced by the axial rupture. The initiation site and chevron marks produced by the circumferential parting were located approximately 3.7 in. (94 mm) from the upper arrest point of the axial rupture. Figure 70 (i.e., Figure 12 above quoted by Mr. Carnahan's testimony) is a schematic of the crack path for the axial rupture and circumferential parting. The schematic shows how the circumferential parting initiated above the arrest point of the axial rupture. The crack propagated circumferentially until it reached the axial rupture arrest point. The final ligament failed due to the axial load generated by the weight and tension of the 7 in. casing string. **The axial rupture and circumferential parting are thought to be two separate events because there was no evidence that the chevron marks from the axial rupture continued into the circumferential parting.** The close proximity of the two failures suggests that they are related despite being two separate events." (emphasis added)

Blade has followed the well established guidelines described in the literature, for example, *Fracture Appearance and Mechanisms of Deformation and Fracture*, Metals Handbook Vol. 11, 2011, pages 559-561 [13], and determined that the SS-25 failure consisted of two separate events because of the absence of evidence showing a single pathway of chevron marks connecting the axial fracture with the circumferential parting. There is no continuity of chevron marks from axial to circumferential. There is an arrest point on the axial fracture as shown by the metallurgical evidence. These facts have to be rationalized in any interpretation of the failure sequence.

Blade disagrees with the interpretation in Mr. Carnahan's testimony.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

No additional context is required. The factual evidence provided in Blade's reports support the fracture sequence described in the report.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's primary assertion that the vertical rupture and the circumferential part were one event, then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.8 Statement 8

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).

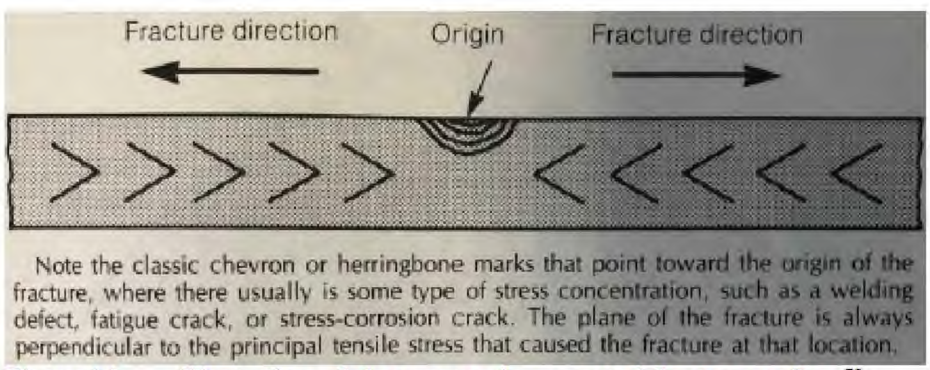



Figure 14. Illustration of chevron marks on a steel fracture surface.[75]


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]

## 2.8.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Blade disagrees with Mr. Carnahan's testimony because he does not show with metallurgical evidence, the extension of the axial fracture to the circumferential parting. Therefore, there is no metallurgical evidence to support the interpretation that axial rupture and circumferential parting are one event.

   Mr. Carnahan's testimony correctly states that "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 provided by Mr. Carnahan in his testimony)", however, he incorrectly states that, "chevron marks on the SS-25 fracture surface show clearly that the circumferential fracture is an extension of the axial fracture (Figure 15)". Mr. Carnahan did not show where in the figure that he clearly saw the chevron marks extending from the axial fracture to the circumferential fracture. In contrast, as previously indicated in Blade's response to Mr. Carnahan's Statement 7, Blade provided macro- and micro-fractographic evidence in the Main and Supplementary Reports, see Figure 67 on page 71 of the Main Report, which shows no chevron marks present after the axial fracture was arrested and no chevron marks on the final overload rupture.

The figure below (Figure 68 (a), page 72 of Blade Main Report) shows no chevron marks on the final overload rupture. For clarity, we have annotated the upper corner on the right-hand side of the figure with the green arrow) indicating no chevron marks on the final overload failure of Zone 3 of the circumferential parting. On the circumferential fracture surface there is no extension of the axial fracture chevron marks.

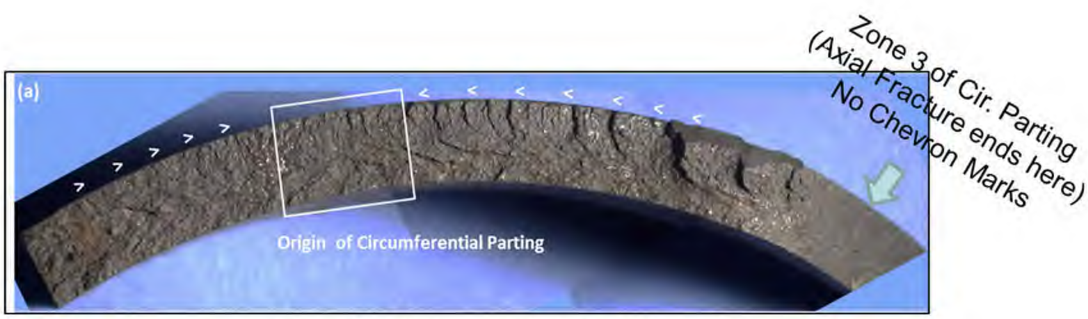



**Figure 68 (a), Page 72 Blade Main Report**

In the caption of Figure 15 below, Mr. Carnahan states "Blade misidentified the chevron marks as flowing towards the origin. Based on both my physical inspection on February 27-28, 2020, and my analysis of the image, the chevron marks travel to the right, as indicated by the red arrows at the bottom of the figure."


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.

Blade disagrees with the statement because the visual and stereomicroscopic examinations performed by Blade showed that the apexes of the chevron marks are in the opposite directions around the origin. This is further clarified in Figure 68(a), page 72 of the Blade Main Report below that shows the chevron marks point back towards the origin from either side of the origin. For clarity, white dashed lines have been added to the figure to outline the chevron marks that point back towards the origin from either side of the origin. This is inconsistent with Figure 16 of Mr. Carnahan's testimony.

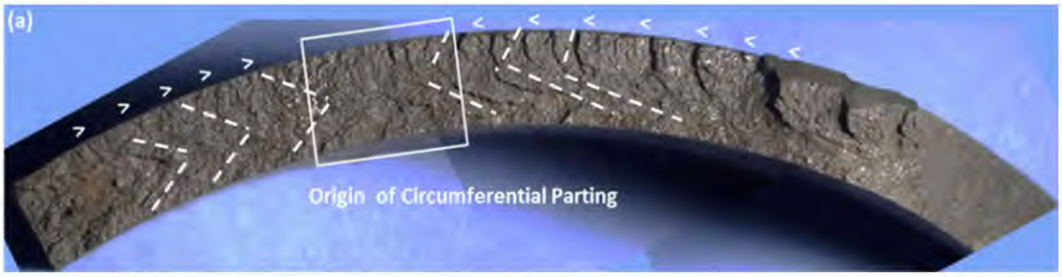



**Figure 68 (a), Page 72 Blade Main Report**

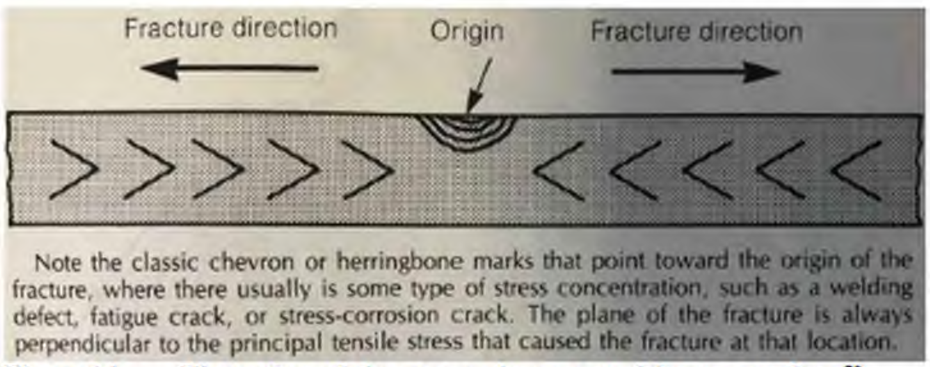



Figure 14. Illustration of chevron marks on a steel fracture surface.[75]

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]

In summary, the explanation provided in the Blade Main and Supplementary reports demonstrates the existence of two events in the failure process:

- The chevron marks are not continuous and do not extend from the axial rupture to the circumferential parting. See Figure 67(a) on page 71 of the Blade Main Report.

- There is a clear indication of arrest at the end of the axial fracture path as shown in the Blade supplementary report *SS-25 Casing Failure Analysis Report* [14]on page 121, Figure 142.
- There are chevron markings in opposite directions on the circumferential fracture surface which point towards the origin, see Figures 68 and 69 on page 72 of the Main Report and Figure 160 on page 134 and Figures 161 and 162 on page 135 of the supplementary report.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's primary assertion that the vertical rupture and the circumferential part were one event, then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.9 Statement 9

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.

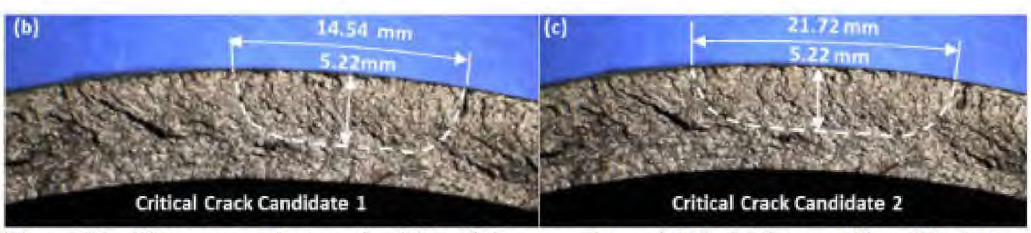



Figure 17. There are no features in either of the areas shown in Blade Figures 68b or 68c that suggest the existence of a fracture origin.

### 2.9.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

An examination of the chevron marks in Figure 17 (i.e., Figure 68 in Blade's Main Report, page 72), showed that the features inside the origin were different from chevron marks outside the origin. The examination identified an area (the origin) that was absent of chevron marks but had chevron marks on either side pointing towards it. For clarity, white dashed lines have been added to outline the chevron marks that point back towards to the origin from either side of the origin. This observation is consistent with the illustration, Figure 14, provided by Mr. Carnahan.

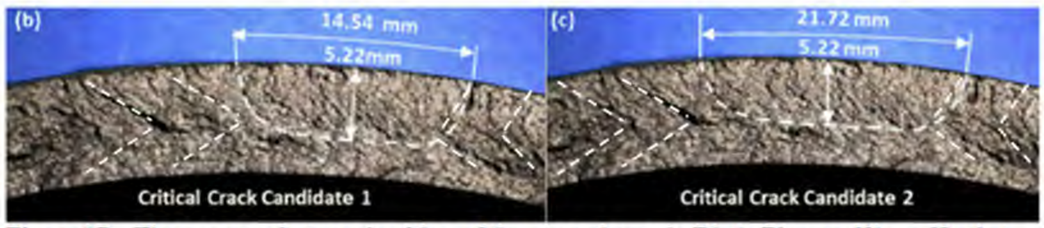



Figure 17. There are no features in either of the areas shown in Blade Figures 68b or 68c that suggest the existence of a fracture origin.

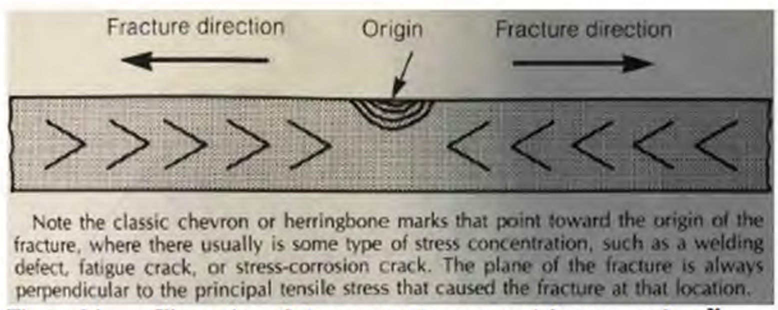



Figure 14. Illustration of chevron marks on a steel fracture surface.[75]

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's primary assertion that the vertical rupture and the circumferential part were one event, then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.10 Statement 10

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.

## 2.10.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

    Disagree.

2. If Blade disagrees with any portion of the statement, why?

    Blade disagrees with Mr. Carnahan's testimony because there is a SEM micrograph in the Blade supplementary report that clearly identifies the circumferential fracture origin. This has not been referenced or discussed in Mr. Carnahan's testimony.

    Blade showed that "the SEM examination of Zone 1 identified a pre-existing crack-like flaw on the OD side of the origin", see Figures 168 and 169 on pages 140 – 141 of the *SS-25 Casing Failure Analysis* supplementary report. The crack-like flaw was shallow, with a measured maximum depth of 196 μm. This was a pre-existing flaw and was associated with the origin of the circumferential fracture. Figure 170 in the same supplementary report shows an EDS analysis indicating that the surface of the flaw was severely oxidized by a scale that could not be removed during cleaning. The adjacent fracture surface was easily cleaned and clearly showed cleavage facets. This observation suggests that the flaw existed prior to the circumferential parting. This OD surface flaw may have promoted brittle cracking to form the origin of the circumferential parting, even though the flaw was shallow. The presence of a pre-existing OD oxidized flaw clearly exhibits that the circumferential parting had a separate initiation site. This information was not considered in Mr. Carnahan's testimony.

    A complete validation of the size of the origin (i.e., the critical crack size for circumferential parting) is given in Section 2.4.4 of Blade's Main Report (page 74) and in Section 4.3 of the *SS-25 Casing Failure Analysis* supplementary report (page 164). Further discussion on this topic in detail is given in the next section, i.e., Blade's response to Mr. Carnahan testimony Statement 11, Section 2.11 in this document.

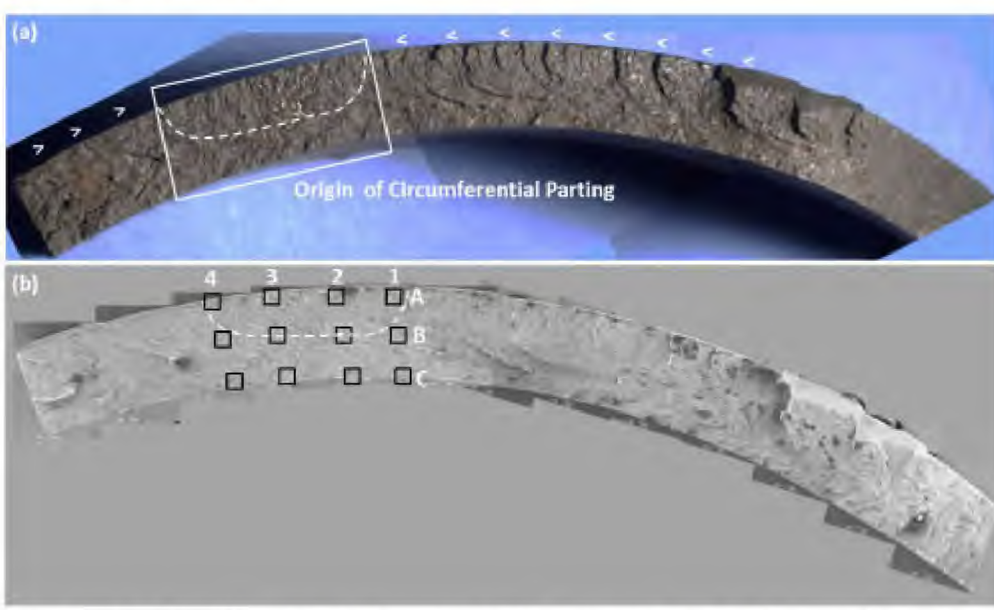



Figure 168: Specimen C023A1A1A (a) Stereo and (b) SEM Images of Zone 1 (Origin) Investigation Areas

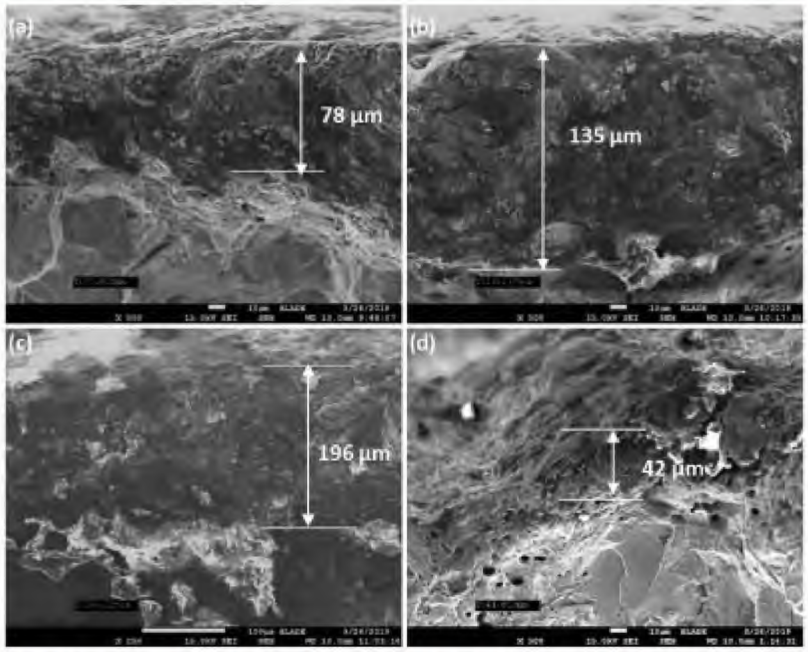
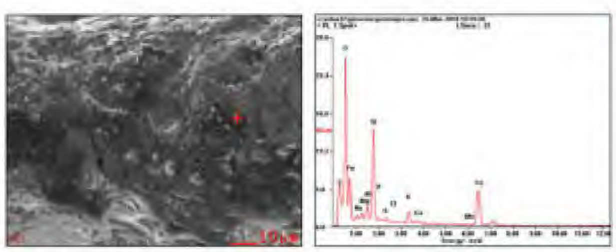



Figure 169: SEM Images of Pre-existing Flaws at (a) 1A, (b) 2A, and (d) 4A Taken at 500×, and (c) 3A Taken at 250×



| Element | Wt% | At% |
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| NaK | 00.30 | 00.35 |
| SiK | 00.48 | 00.46 |
| SK | 00.24 | 00.20 |
| ClK | 00.51 | 00.39 |
| CaK | 00.24 | 00.16 |
| MnK | 00.71 | 00.35 |
| FeK | 59.62 | 28.74 |
| Matrix | Correction | ZAF |

(a) SEM image. The red spot is where the EDS analysis was performed

(b) EDS Spectra. A high oxygen peak is noticeable

(c) Concentration of the scale showed iron oxide

Figure 170: EDS Results for Pre-Existing Flaws

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. Blade did identify an origin for the circumferential fracture, the evidence was provided by the stereo microscopic and SEM micrographs in the Blade supplementary report. If, however, Mr. Carnahan's testimony is considered to be true, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

Not applicable, no conclusions change.

## 2.11 Statement 11

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.

### 2.11.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Blade did identify two semi elliptical areas as possible critical crack sizes (origin) for the circumferential parting based on thorough examination with the stereo microscope and SEM; it was 5.22 mm deep and either 14.54 mm long or 21.72 mm long. The exact length is later established in the Blade report as 21.72 mm long.

   Blade identified the fracture origin of the circumferential parting based on the observed apexes of the chevron marks pointing at the origin, along with the presence of a pre-existing OD oxidized flaw. This was also discussed in Statements 9 and 10. Blade identified two semi elliptical areas as possible critical crack sizes (origin) for the circumferential parting based on thorough examination with the stereo microscope and SEM, one is 14.54 mm long x 5.22 mm deep and the other one 21.72 mm long with the same depth, see pages 71 and 72 of Blade's Main Report and Section 3.3.1 on page 134 of Blade's supplementary report *SS-25 Casing Failure Analysis* for details. Figure 17 provided by Mr. Carnahan in Statement 9 (i.e., Figure 68 in Blade's Main Report, page 72), with added dashed lines to outline the chevron marks), showed that the features inside the origin were different from chevron marks outside the origin. The examination identified an area (the origin) that was absent of chevron marks but had chevron marks on either side pointing at it.

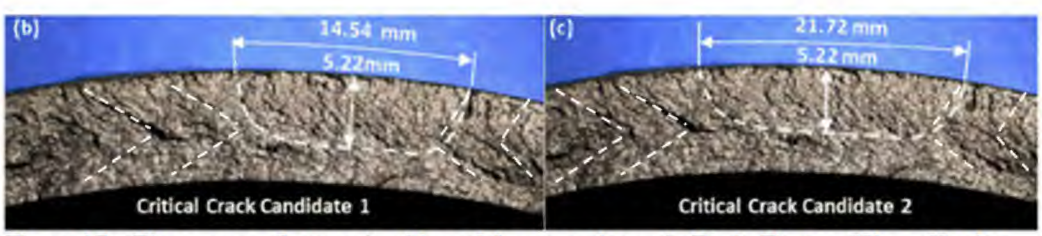



Figure 17. There are no features in either of the areas shown in Blade Figures 68b or 68c that suggest the existence of a fracture origin.

The location of the origin is often well identified, and uncertainty in origin sizing is not uncommon. Therefore, it is common practice that the identified candidate flaw sizes are often validated or refined using fracture mechanics methods or FEA and other methodologies. Such an approach was undertaken for the circumferential flaw.

The validation of the two possible sizes of the origin (critical crack size) for circumferential parting was performed using the following approach:

- Fracture mechanics calculation of the applied stress intensity factor for each of the possible origin size, i.e., the driving force for circumferential parting using the flaw size and axial load as per API 579 [15] and BS 7910 [16] procedures (see Section 4.3.1 of the *SS-25 Casing Failure Analysis* supplementary report, pages 164-165 for details)

- Fracture toughness from CVN was estimated as a function of temperature using API 579 and BS7910 recommended procedures (see Section 4.3.3 of the supplementary report, pages 167-168 for details)
- An independent estimate of the casing temperature at time of failure using a thermo hydraulic model (see Section 4.3.4 of the supplementary report, page 169 for details)

By comparing the validation methods above, one of the two possible size of the origin, that is, the one having the size of 21.72mm long x 5.22 mm deep was validated as the most likely critical crack size for the circumferential parting. This is discussed in detail in Blade Main and supplementary reports.

For this failure, Blade integrated two different approaches to refine the origin. The origin was first established using microscopy and visual observations. Next, Blade used fracture mechanics and temperature, followed by toughness (established through laboratory testing) to finalize the origin size. Using one methodology such as, macro- and micro- fractographic methods, to interpret failure is inadequate for failure analysis; such interpretation has to be consistent with quantitative fracture mechanics estimates.

Consequently, Blade has unequivocally established that the circumferential parting initiated from the origin identified by using microscopy, visual observations and fracture mechanics.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

    No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

    Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's assertion that "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) is consistent with the absence of features identifying it as an origin", then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

    Not applicable, no conclusions change.

## 2.12 Statement 12

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.

## 2.12.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Because the circumferential parting had initiated from a crack-like surface flaw at a temperature below the steel ductile to brittle transition temperature (DBTT), the micro fracture mode would be cleavage. One would not expect any noticeable change in the micro fracture mode outside of the origin that was produced at the same temperature below the ductile to brittle transition temperature of the steel. This was a temperature driven fracture mode. The absence of a ductile origin is consistent with the low temperature experienced, prior to circumferential parting and after the axial rupture, due to escaping gas. As discussed previously, data from all aspects of the failure (metallurgical, loads, temperatures) should be integrated to deliver a precise interpretation. Just interpreting metallurgical data alone is inadequate. A comprehensive interpretation is crucial to identifying the fracture sequence.

   The SEM images below show the origin was initiated from a crack like surface flaw by cleavage (Figures 169 and 170 on page 141, *SS-25 Casing Failure Analysis* supplementary report).

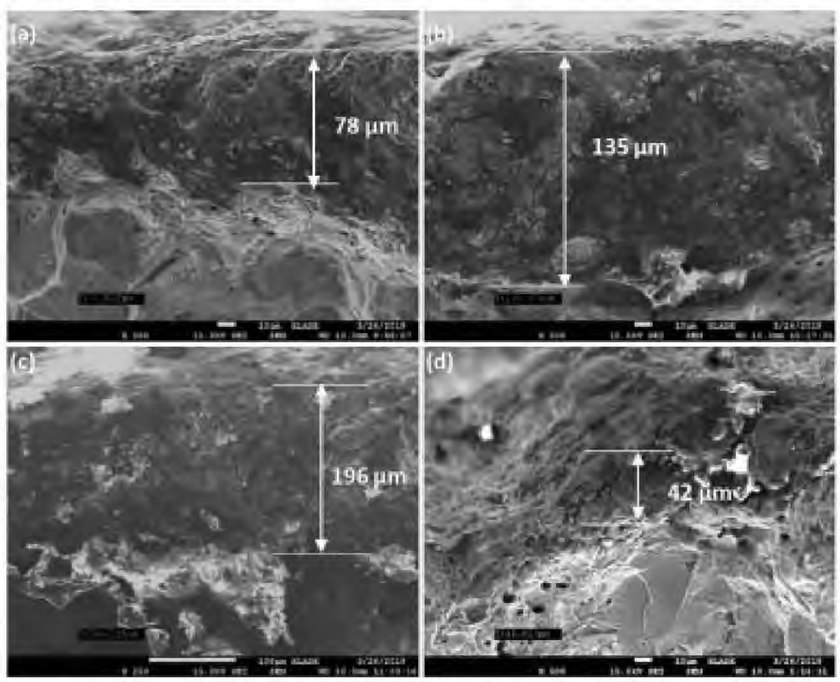
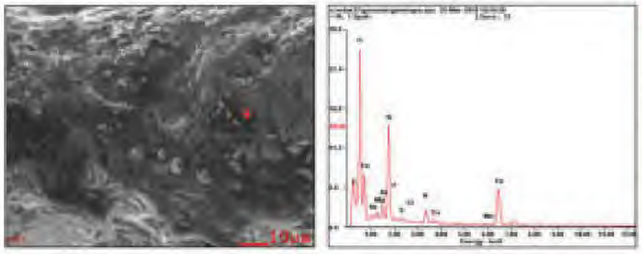



Figure 169: SEM Images of Pre-existing Flaws at (a) 1A, (b) 2A, and (d) 4A Taken at 500×, and (c) 3A Taken at 250×



| Element | Wt% | At% |
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| CK | 09.93 | 22.27 |
| OK | 27.98 | 47.08 |
| NaK | 00.30 | 00.35 |
| SiK | 00.48 | 00.46 |
| SK | 00.24 | 00.20 |
| ClK | 00.51 | 00.39 |
| CaK | 00.24 | 00.16 |
| MnK | 00.71 | 00.35 |
| FeK | 59.62 | 28.74 |
| Matrix | Correction | ZAF |

(a) SEM image. The red spot is where the EDS analysis was performed

(b) EDS Spectra. A high oxygen peak is noticeable

(c) Concentration of the scale showed iron oxide

**Figure 170: EDS Results for Pre-Existing Flaws**

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's assertion: that "Blade's scanning electron microscope (SEM) photos of the hypothesized origin show predominantly cleavage features. Blade reported that no noticeable changes in fracture mode were observed outside of the origin 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", then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.13 Statement 13

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

### 2.13.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

Blade's analysis of the circumferential parting followed well-established guidelines for determination of the failure origin, and the evidence of discontinuity of chevron marks between circumferential parting and axial rupture provide a sound scientific basis to conclude that the circumferential parting occurred as a separate event. The circumferential fracture mode was a temperature driven process, consequently, the origin has cleavage features that is consistent with fracture under low temperatures.

The rationale for Blade's findings has been discussed in the responses to Statements 10, 11, and 12.

Moreover, as indicated in the previous Statement, on pages 140 – 142 of the *SS-25 Casing Failure Analysis* supplementary report, Blade clearly indicated that "the SEM examination of Zone 1 of the circumferential parting identified a pre-existing, crack-like flaw on the OD side of the origin. The OD surface flaw may have promoted brittle cracking from the origin of the circumferential parting, even though the flaw was shallow". In other words, a brittle crack (i.e., the origin) was initiated from the crack like surface flaw at a temperature below ductile to brittle transition temperature (DBTT) and the brittle crack size was larger than the critical crack size at that temperature, resulting in crack instability and the circumferential brittle parting. One would not expect any noticeable change in micro fracture mode within and outside of the origin that was produced at a temperature below ductile to brittle transition temperature of the steel. This was temperature driven fracture mode.

A complete validation of the size of the origin (critical crack size) is given in Section 2.4.4, pages 74 – 79 of Blade's Main Report and Section 4.3, pages 164 – 169 of the *SS-25 Casing Failure Analysis* supplementary report.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's assertion that "Blade's analysis of the circumferential parting is logically flawed.", then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.14 Statement 14

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.

## 2.14.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   There are two issues raised here by Mr. Carnahan: (a) there is no fractographic evidence showing arrest of the vertical fracture extending upward from the area of the burst and (b) 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. Blade's response to Mr. Carnahan's testimony is as follows:

   **Issue (a):** there is no fractographic evidence showing arrest of the vertical fracture extending upward from the area of the burst.

   **Blade's Response to Issue (a):** Blade did provide extensive macro and micro fractographic evidence showing arrest of the vertical fracture extending upward from the area of the burst. The evidence was provided and discussed in the *SS-25 Casing Failure Analysis* supplementary report on page 76 (Figure 78), page 81 (Figure 86, Macro), page 82 (Figure 87, Macro), page 109 (Figures 123, 124, Macro), page 121 (Figures 142 and 143, Macro), page 122 (Figure 144 Micro), page 124 (Figure 146 Micro), and page 146 (Figure 178 Macro).

   As stated in the supplementary report, Figure 78 (page 76) and Figure 86 (page 81) illustrates the upper (upward) turning point, second upper (upward) turning point, and arrest point. The images show the upper (upward) section of the axial rupture. Figure 87 (page 82) shows the lower (downward) turning and arrest points.

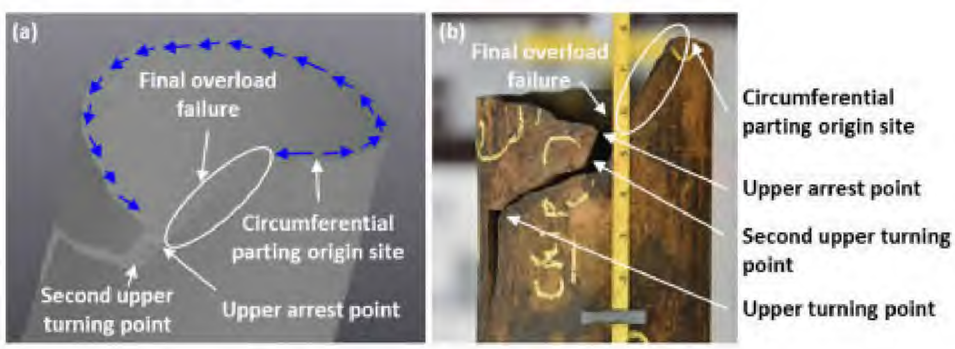



Figure 78: (a) Laser Scan and (b) Circumferential Parting

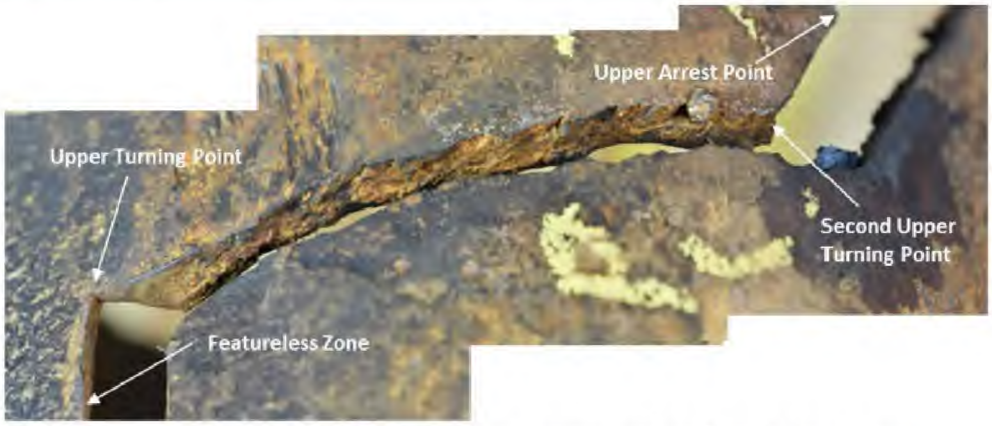



Figure 86: Macro Image of the Two Upper Turning Points and Single Arrest Point

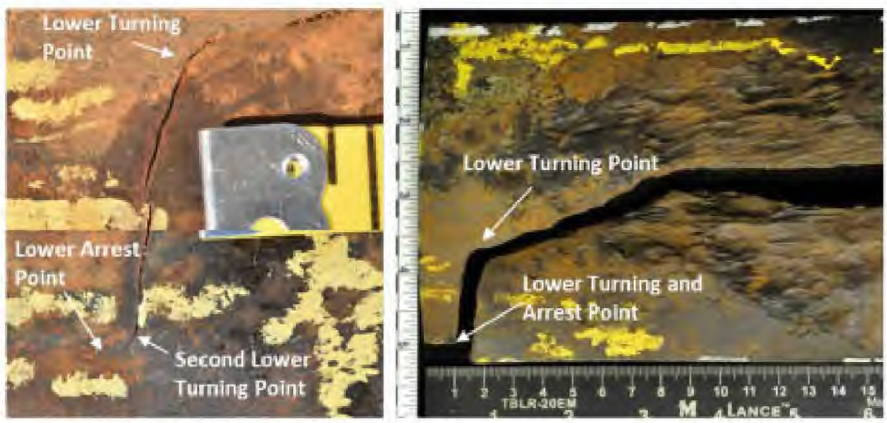



Figure 87: Macro Images of the Lower Turning and Arrest Points

Figure 142 (page 121 in the supplementary report) below shows more detail on the second upper (upward) turning point and upper (upward) arrest area. The upper (upward) arrest area is identified by a slight angle change on the inclined surface. The fracture surface of the upper (upward) arrest area shows no chevron marks because the axial crack was arrested.

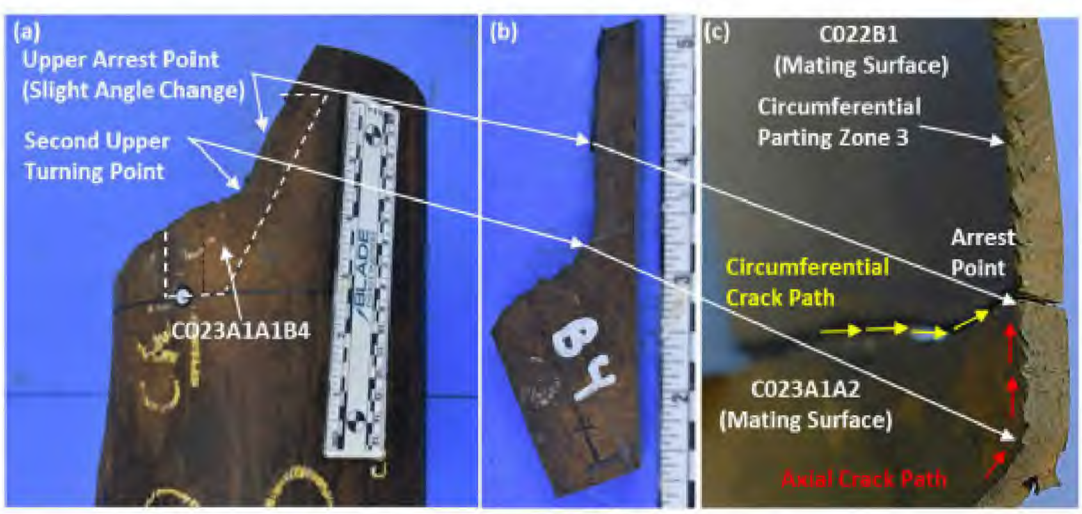



Figure 142: Specimen C023A1A1B4 Extraction

Figure 146 (page 124 of the supplementary report) below are the SEM images of the axial upper (upward) arrest area showing no cleavage facets. There are two observations in the arrest region that support the fact that the crack was arrested. First is the absence of chevron marks observed with a stereo microscope. Secondly, the absence of cleavage facets, observed using a SEM in the same region. Both of these factors support the interpretation that the axial crack slowed down and arrested in this region around a temperature of 80°F. Had the crack propagated per Mr. Carnahan's hypothesis, there should have been chevron marks and cleavage facets in this axial to circumferential transition region, identified as Zone 3.

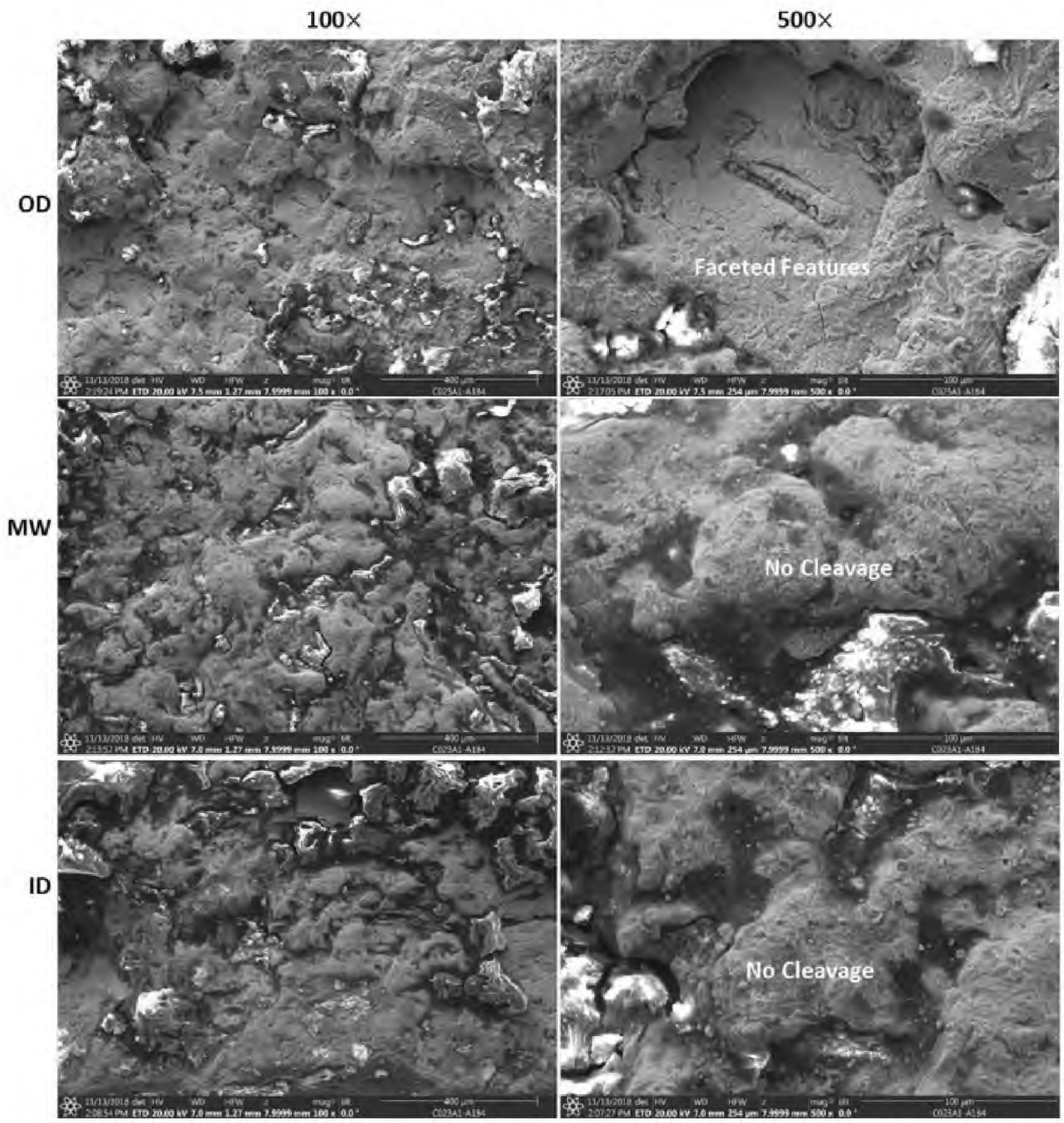



**Figure 146: Specimen C023A1A1B4 A3 Showing OD, MW, and ID at 100× and 500×**

Figure 178 (a) (page 146 of the supplementary report) shows a schematic of Zone 3 of final circumferential parting. The yellow arrow points to Figure 178 (b) and (c) that show macro and stereo images at a higher magnification of Zone 3. The images show a step-like appearance on the

ID side of the fracture surface. The OD side of the fracture surface appears to be smooth. The fracture surface shows no evidence of chevron marks.

The SEM examination (Figure 180 on page 148 of the supplementary report) showed that the fracture surface near the OD side was mostly cleavage separation, while the ID side showed a mix of cleavage facets and a woody type of plastic deformation. The fracture surface morphology at the mid-wall was a combination of the OD and ID morphologies. This evidence is consistent with the brittle overload failure at temperature below ductile-brittle transition temperature (DBTT).

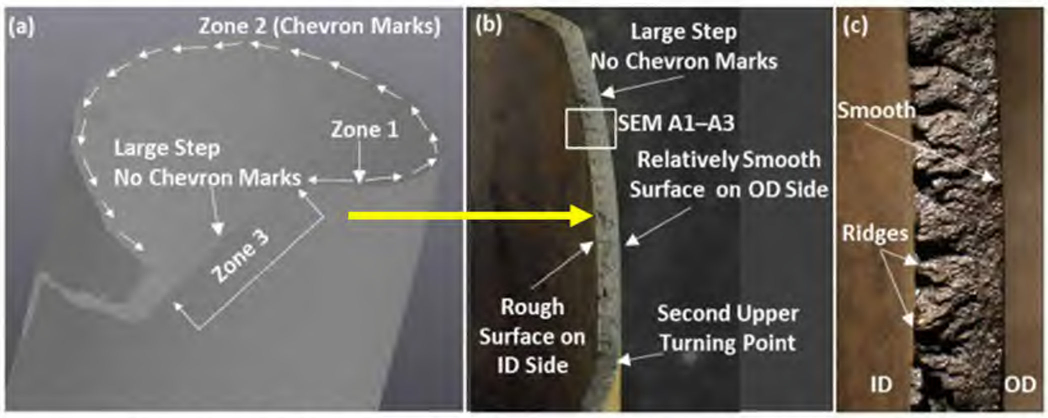



Figure 178: (a) Schematic and (b) (c) Image of Zone 3 (Final Overload Failure)

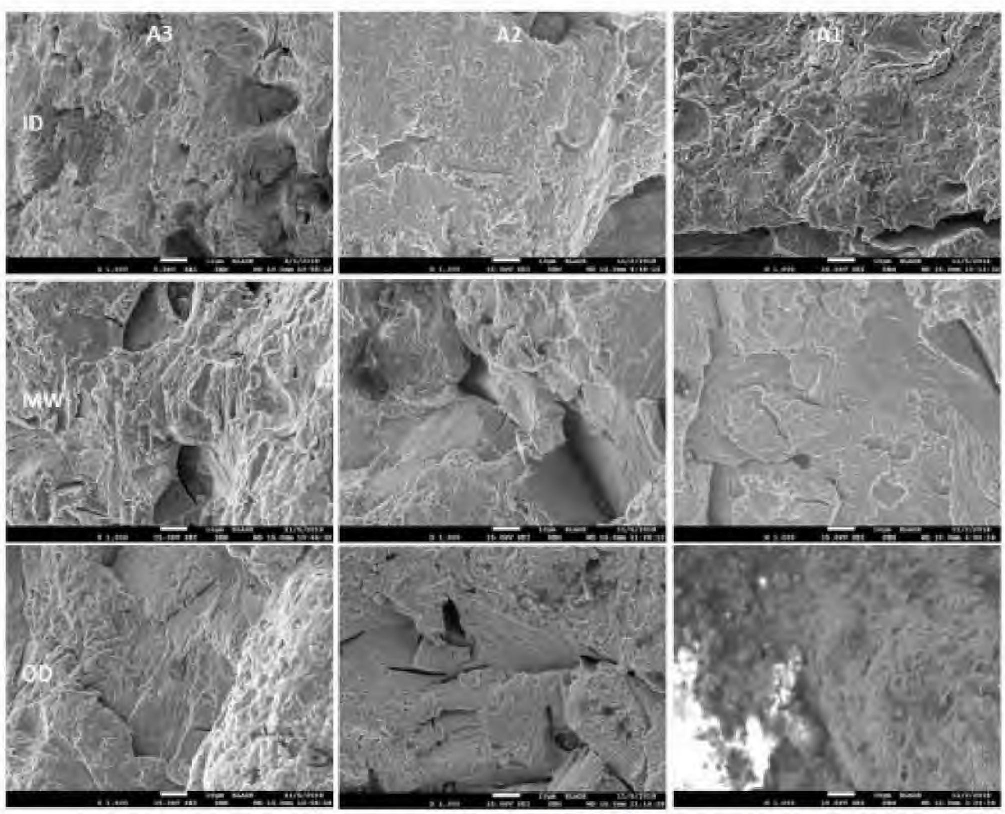



Figure 180: Fracture Surface Morphologies near the ID, MW, and OD Taken at 1,000×

Based on evidence discussed above and other data, Blade's Main Report states on page 54 "Visual and stereoscopic examination of the circumferential parting showed that the failure was not a continuation of the axial rupture, but rather re-initiated near the corner on one side of the parted casing". If it was a single event from the axial (vertical) rupture to the circumferential parting, there should be a single continuous pathway of chevron marks. The evidence does not support a single event because both the upward arrest area of the axial rupture and Zone 3 of circumferential parting do not contain chevron marks. Therefore, the vertical and circumferential fracture are two separate events with their own initiation sites.

**Issue (b):** 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.

**Blade's response to Issue (b):** Blade disagrees with Mr. Carnahan's statement that the crack may have arrested at the wall thickness change near the connection. The arrest point was about 9 in. from the start of the change in wall thickness of the casing pin connection, therefore the arrest is not coincident with the wall thickness change. However, Blade does agree that the connection contributed to the lower arrest point. Blade has addressed this issue in its supplementary report *SS-25 Casing Failure Analysis* (Section 3.2.1, page 78). Figure 81 (page 79) shows that the origin was not symmetrically located at the center of the rupture. The non-symmetric location of the origin can be explained by the proximity of the origin to connection 22. The axial crack initiated in Zone 1 and propagated in opposite directions. The lower (i.e., "downward" used by Mr. Carnahan) crack front propagated towards connection 22, which provided additional constraint. Parameters that may contribute to the constraint include connection make up stresses and residual stresses due to local deformation. The upper crack was not influenced by any additional constraint allowing the crack to propagate further before arresting.

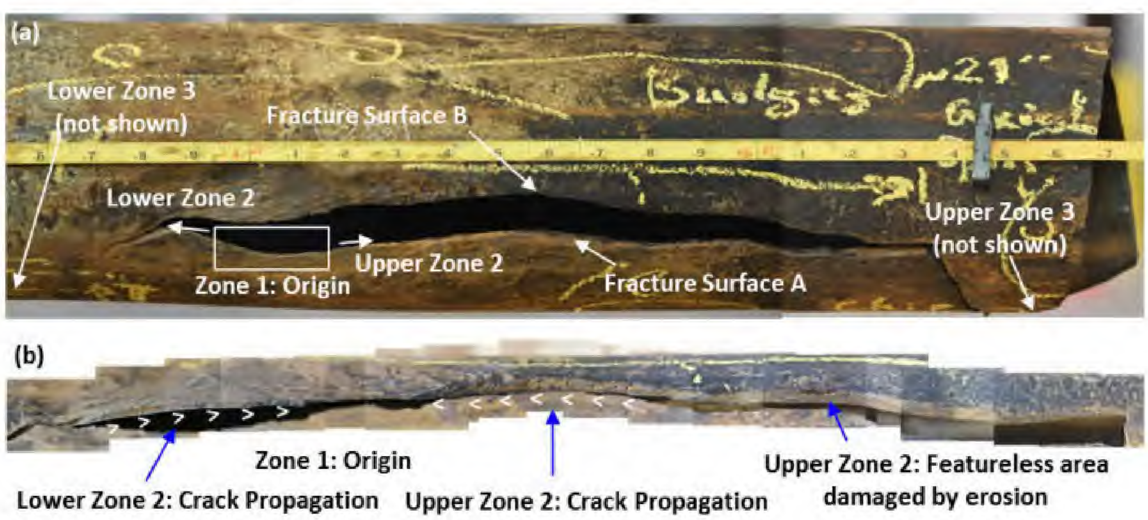



**Figure 81: (a) Front and (b) Top Views of Fracture Surface B Identifying Zones 1 and 2**

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's assertion then it would only change Blade's interpretation on the failure sequence.

However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.15 Statement 15

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.

### 2.15.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   There were two events. The axial rupture happened at a temperature around 80°F. However, following the axial rupture the temperature dropped locally, and then the circumferential parting occurred. Blade has provided extensive evidence to support this interpretation.

   Firstly, Mr. Carnahan's testimony "The 7-in. casing did not have to become cold for the circumferential fracture to occur" ignores the evidence provided in Blade's Main Report, is subjective, and without any basis. The fact is, as stated on page 55 in Blade's Main Report, that "the circumferential parting was brittle, which was different from the axial rupture. No evidence of local plastic deformation or overload necking was observed near the fracture surfaces on either side of the circumferential parting" and "a temperature for the circumferential parting was estimated to be in the range of –76°F to –38°F (–60°C to –39°C)" based on the critical defect size and fracture mechanics models (API 579 FAD and BS7910 FAD) (Table 6 on page 79 of the Main Report) and a series of CVN tests (Sections 4.3.1, pages 164 – 166 of the *SS-25 Casing Failure Analysis* supplementary report).

   Mr. Carnahan does not address the absence of local plastic deformation or lack of overload necking in the circumferential parting region, which would be required to validate or support Mr. Carnahan's contention. Further, Mr. Carnahan has not assessed the fact that the tensile load was low and could not have failed the casing in the circumferential orientation unless the temperature dropped and the toughness was reduced. Integration of stresses, metallurgical factors and temperature is necessary here to interpret the failure sequence.

   Secondly, Blade agrees with Mr. Carnahan's testimony that "The fracture that extended vertically upward from burst area did not require cooling of the material". In Blade's Main Report, it is clearly stated that the axial rupture occurred at an estimated temperature of 80°F; this estimate was based on the historical temperature profile data at the failure depth of 892 ft (joint 22) and is consistent with observed bulging and ductile tearing associated with the axial rupture (page 74 in Section 2.4.4 of Blade's Main Report). Blade never states anywhere in the report that the fracture that extended vertically upward from the burst area required cooling of the material.

   Thirdly, Blade disagrees with Mr. Carnahan's statement "Similarly, no further cooling would be required for this fracture to change direction and propagate circumferentially". This statement is not relevant to the failure at SS-25.There were two events, the axial rupture occurred at 80°F, whereas the circumferential parting occurred at a much lower temperature. This has been previously discussed in detail. There is a preponderance of evidence that supports Blade interpretation.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's conclusion in the above statement. Blade does agree with Mr. Carnahan's testimony "The fracture that extended vertically upward from burst area did not require cooling of the material." This is consistent with Blade's conclusion in its reports. Mr. Carnahan's testimony, if accepted to be true in its totality, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.16 Statement 16

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.

### 2.16.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Fracture mechanics text books [17] [18] [19] and extensive literature [20] [21] [22] [23] [24] have explained the crack arrest concept. The driving force for a running crack is dynamic and decays as a function of time, as described in fracture mechanics text books and literature. It depends on two factors: (a) the rate of internal pressure drop due to the release of liquid or gas and (b) the resistance to crack propagation that is dependent on the material's crack arrest toughness (CVN, KJ, CTOA, etc.). Developing the methods for arrest of a running crack in steels is the focus of fracture mechanics for safety and minimizing consequences of rupture [20] [21] [22]. The evidence provided by the SS-25 RCA has shown that the running axial crack in the SS-25 7 in. casing was arrested.

   Figure 4 presents a schematic of the failure process [25]. The sketch in the red box conceptually summarized the conditions for crack arrest, that is, a through-wall defect ruptures but arrests if the pressure is low, and/or if the pipe material toughness is high.

   The differential pressure at the time of the SS-25 7 in. casing axial rupture was 2,405 psi (Table 5, page 156, *SS-25 Casing Failure Analysis* supplementary report), the calculated hoop stress is only

42.6% of actual yield strength, which was a low stress failure, i.e., a low driving force for failure. On the other hand, the temperature at the time of the axial rupture was 80°F. The material exhibited high ductility and toughness. Therefore, this was a low driving force and high resistance failure condition, which falls in the crack arrest category. Therefore, the upward crack would eventually be arrested.

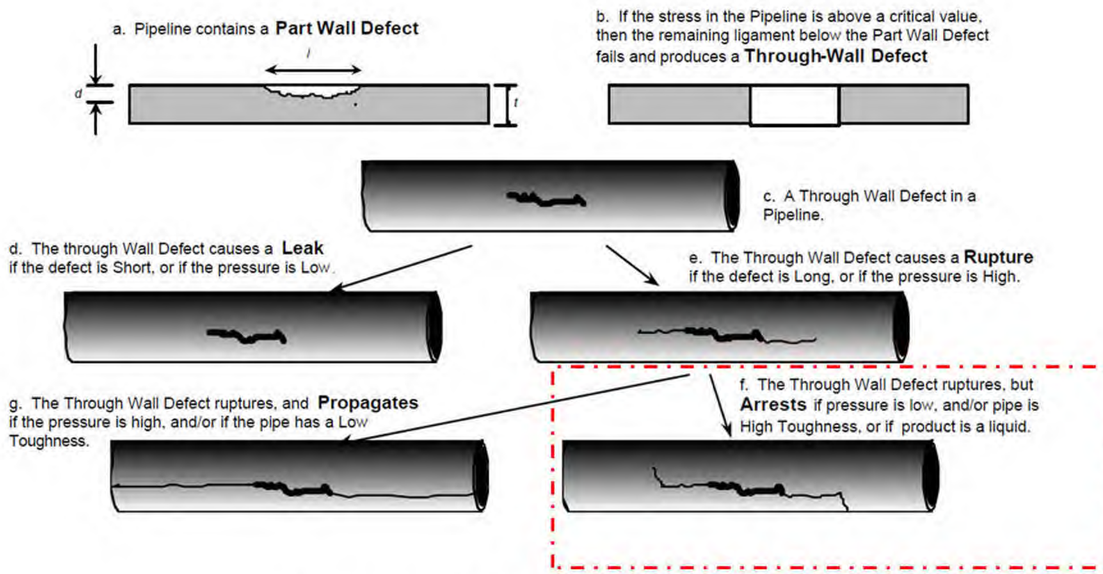



**Figure 4: Pipe Failure Process**

The crack arrest phenomenon as observed in the SS-25 7 in. casing has been discussed in literature, for example ASM Handbook Volume 12 *Fractography Visual Examination and Light Microscopy* and Vol. 20 *Material Selection and Design Chapter Using Failure Analysis in Material Selection*. The figure below is reproduced from ASM Vol 20 showing the arrested axial crack in a full section of X60 grade line pipe by ductile fracture at 13°C (56°F) which is 8°F above its 50% shear-area. The crack, moving at 278 ft/s (85 m/s), stopped after a short distance. The fracture was ductile and the line pipe was tough enough at this temperature to arrest the crack.

**Fig. 1** Ductile fracture of a full section X60 grade line pipe tested at 56 °F (13 °C), which is 8 °F above its 50% shear-area DWTT

Therefore, Blade disagrees with Mr. Carnahan's statement "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". This statement is inconsistent with literature data and understanding regarding running cracks and crack arrest phenomena. Blade supplementary report, *SS-25 Failure Analysis*, on page 73 states, "The visual examination showed that during the axial rupture, plastic bulging occurred first with slow ductile tearing due to the internal pressure. Tearing instability occurred once the axial flaw reached the critical size and was followed by a rapid crack propagation in the axial direction that left behind chevron marks (Figure 76 [c]). The crack changed direction (upper and lower turning points) and finally arrested due to dynamic energy consumption (17) (18) (19). There were two turning points on the upper and lower side of the rupture. This phenomenon is not uncommon for an axial rupture."

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   Blade does not accept any part of Mr. Carnahan's statement as true. If Blade were to accept Mr. Carnahan's assertion that "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", then it would only change Blade's interpretation on the failure sequence. However, it would not change the failure analysis conclusions. The failure was caused by 85% metal loss due to external corrosion. It would not change any of the RCA conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable, no conclusions change.

## 2.17 Statement 17

Pages 28-30 of Mr. Carnahan's testimony, which states:

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 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.

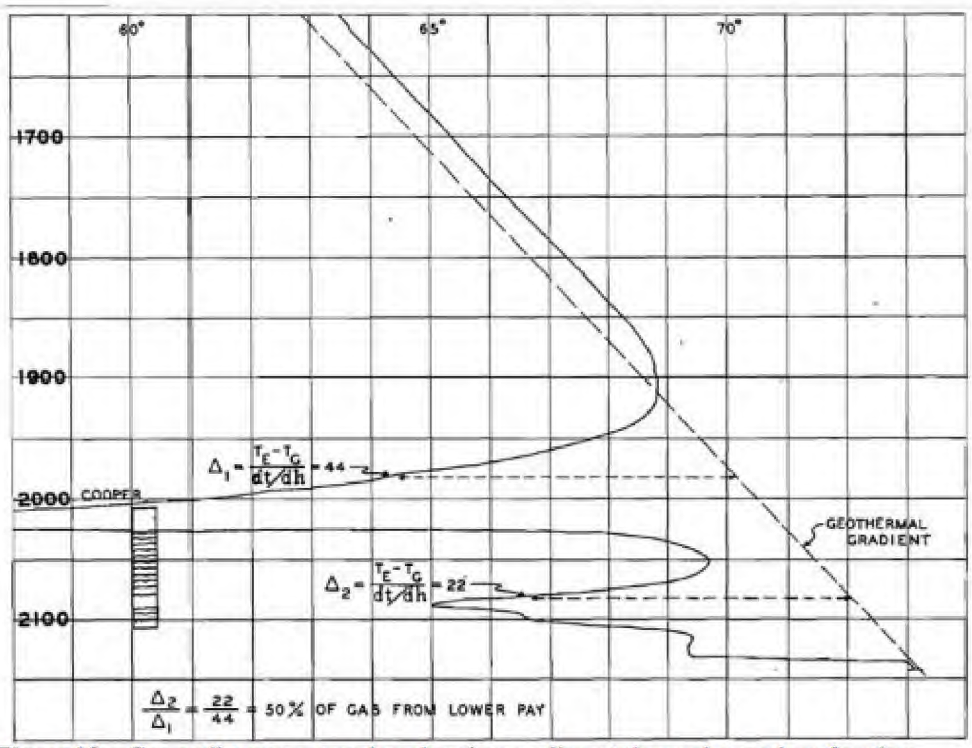



Figure 19. Gas well temperature log showing cooling at the packer and perforation (Bird, 1954).

## 2.17.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   Blade discussed this phenomenon in supplementary report *SS-25 Temperature, Pressure, and Noise Log Analysis* [26, p. 16].

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.18 Statement 18

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).

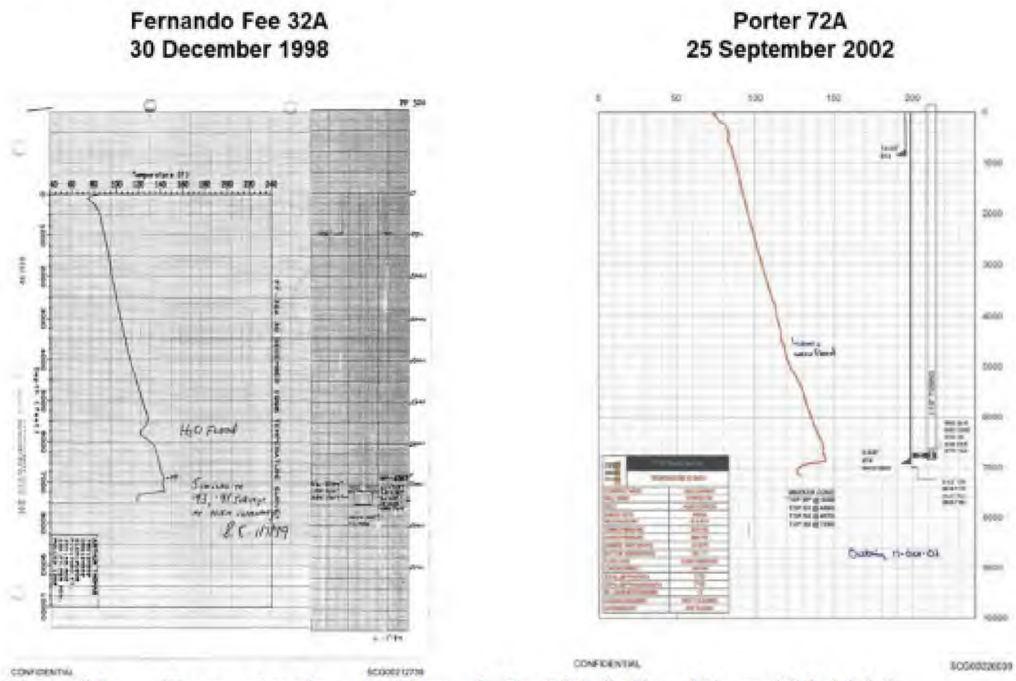



Figure 20. Temperature logs for Fernando Fee 32A (left) and Porter 72A (right).

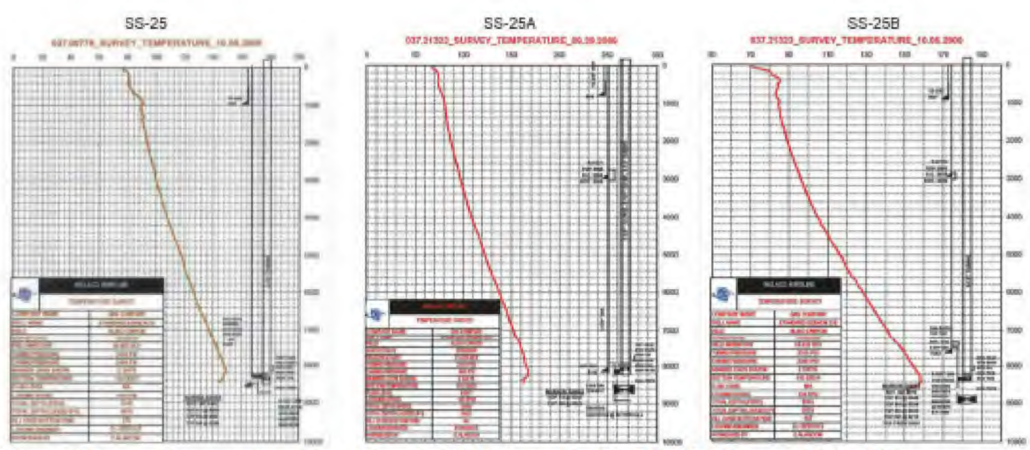



Figure 21. Temperature logs taken in 2009 in wells SS-25, SS-25A, and SS-25B.

### 2.18.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   Blade agrees with this statement, and has discussed the cooling in a supplementary report [27, p. 16].

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.19 Statement 19

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.

### 2.19.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Blade agrees with, "None of these noise logs indicate a gas leak in the production casing."

   Blade disagrees with, "None of these noise logs indicate a gas leak . . . at the production casing shoe."

2. If Blade disagrees with any portion of the statement, why?

   One of the noise logs, performed on April 11, 1984, identified a possible leak near the production casing shoe. Multiple temperatures logs and a radioactive tracer survey were run during this period. This casing shoe leak was not observed in subsequent noise logs. More importantly, there was never any indication via noise or temperature logs of any casing integrity issues prior to October 23, 2015 incident.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   Figure 5 shows the April 11, 1984 log [28]. Denoted in yellow in the Results and Remarks section is, "POSSIBLE SLIGHT SHOE LEAKAGE MIGRATING HIGHER THAN 8440'" at a shut-in pressure of 1,595 psi. Note the purpose of the survey was to "CHECK FOR SHOE LEAK".

   Figure 6 shows the July 27, 1984 log [29]. Denoted in yellow in the Results and Remarks section, "NO INDICATION OF ANY GAS LEAKAGE" at a shut-in pressure of 2,390 psi. Also note the purpose of the survey was to "TO CHECK FOR GAS LEAKAGE AT THE CASING SHOE AND/OR THE W. S. O. ". The W. S. O. refers to the water shut off perforations.

The shut-in tubing and casing pressures during the July 27, 1984 noise survey is 795 psi higher than during April 11, 1984 noise survey. Leaks are almost always more prominent when the pressures are higher. If the casing shoe leak was present it should have been evident at the higher pressure (i.e., inventory) and observed on the July 27, 1984 noise log and subsequent logs.

| | | | |
|---|---|---|---|
| PERMANENT DATUM | 6' K.B. | ELEVATION | 2927' |
| LOG MEASURED FROM | 6' AGL. | CORRECTED TO | TUBING TAIL |
| TOTAL DEPTH | 8748' | OBSERVED DEPTH (Pickup) | 8709 |
| TOP OF LOGGED INTERVAL | 200 | BOTTOM LOGGED INTERVAL | 8709 |
| TYPE OF FLUID IN HOLE | GAS | FLUID LEVEL | ? |
| LOG RECORDED BY | CLARK & HELMS | WITNESSED BY | BRET LANE |

CASING AND TUBING RECORD

| Size | Weight | From | To |
|---|---|---|---|
| 11-3/4" | 42 | 0 | 990 |
| 7 | 23 | 0 | 8585 |
| 5-1/2 | 20 | 8559 | 8748 |

WELL STATUS SHUT-IN GAS STORAGE

| Pressure | Flowing | Injecting | Shut-in |
|---|---|---|---|
| TBG | | | 1595 |
| CSG | | | 1595 |

INJ. RATE TYPE

OBS. RATE

PRODUCTION: Oil Gravity: °API

Water

Gas

BOTTOM TEMPERATURE

TUBING SIZE 2-7/8 DEPTH 8496

PACKER(S) 8491

MANDREL(S) 8405

PERFORATIONS 8510-38, 8542-8559' 8592-8748'

LOGGING UNIT 711 LINE SIZE 3/16" LINE LENGTH 20,000'

TOOLS USED 5' BAR 5' BAR 5' BAR CCL TEMP NOISE

TOOL NUMBERS 4030

DIAMETER 1-3/8'

RESULTS AND REMARKS: POSSIBLE SLIGHT SHOE LEAKAGE MIGRATING HIGHER THAN 8440' (NOTE TEMPERATURE BREAK AROUND 6800'.)

COMPANY SOUTHERN CALIFORNIA GAS

WELL NO. STANDARD SESNON No. 25

FIELD ALISO CANYON

COUNTY LOS ANGELES STATE CA

DATE 4-11-84

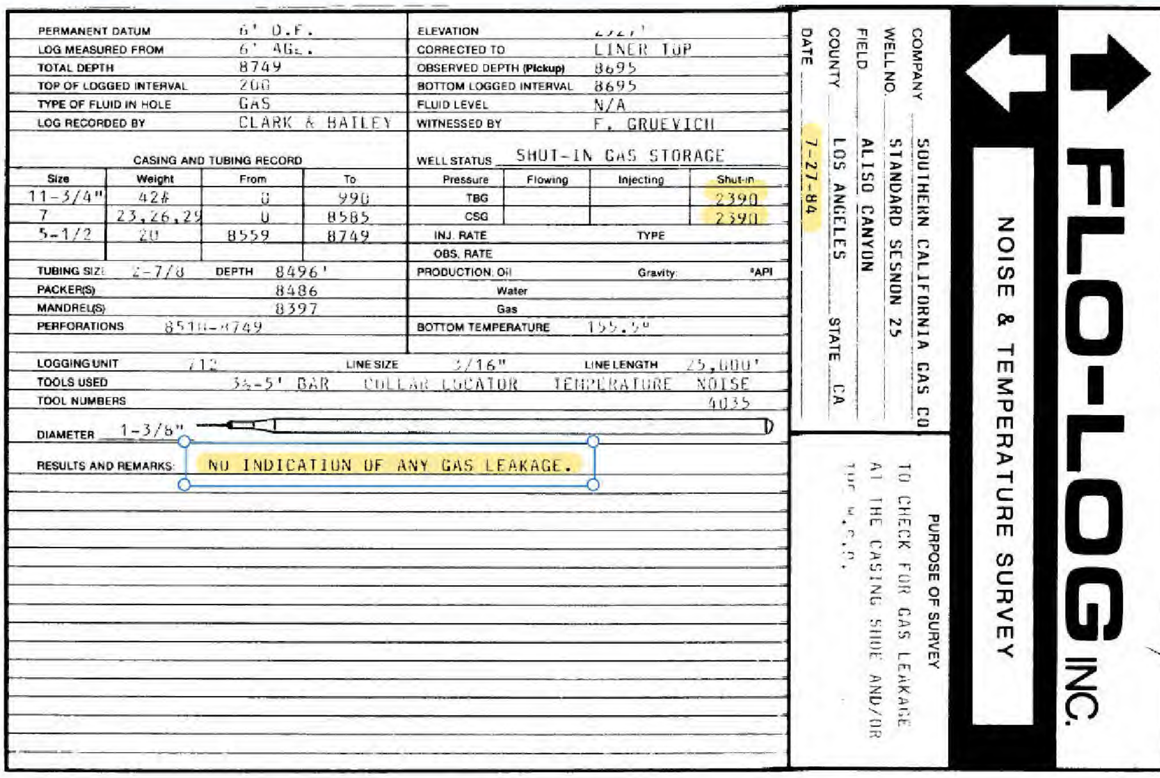
NOISE AND TEMPERATURE SURVEY

PURPOSE OF SURVEY

CHECK FOR SHOE LEAK.

FLO-LOG INC.

**Figure 5: SS-25, Noise Log Header on April 11, 1984, "Possible Slight Shoe Leakage", 1,595 psi**



FLO-LOG INC.

NOISE & TEMPERATURE SURVEY

| | |
|---|---|
| COMPANY | SOUTHERN CALIFORNIA GAS CO |
| WELL NO. | STANDARD SESNON 25 |
| FIELD | ALISO CANYON |
| COUNTY | LOS ANGELES STATE CA |
| DATE | 7-27-84 |

PURPOSE OF SURVEY: TO CHECK FOR GAS LEAKAGE AT THE CASING SHOE AND/OR

| | | | |
|---|---|---|---|
| PERMANENT DATUM | 6' D.F. | ELEVATION | [illegible] |
| LOG MEASURED FROM | 6' AGL. | CORRECTED TO | LINER TOP |
| TOTAL DEPTH | 8749 | OBSERVED DEPTH (Pickup) | 8695 |
| TOP OF LOGGED INTERVAL | 200 | BOTTOM LOGGED INTERVAL | 8695 |
| TYPE OF FLUID IN HOLE | GAS | FLUID LEVEL | N/A |
| LOG RECORDED BY | CLARK & BAILEY | WITNESSED BY | F. GRUEVICH |

CASING AND TUBING RECORD

| Size | Weight | From | To |
|---|---|---|---|
| 11-3/4" | 42# | 0 | 990 |
| 7 | 23,26,29 | 0 | 8585 |
| 5-1/2 | 20 | 8559 | 8749 |

WELL STATUS SHUT-IN GAS STORAGE

| Pressure | Flowing | Injecting | Shut-in |
|---|---|---|---|
| TBG | | | 2390 |
| CSG | | | 2390 |

INJ. RATE TYPE

OBS. RATE

TUBING SIZE 2-7/8 DEPTH 8496'

PACKER(S) 8486

MANDREL(S) 8397

PERFORATIONS 8510-8749

PRODUCTION: Oil Gravity: °API

Water

Gas

BOTTOM TEMPERATURE 155.5°

LOGGING UNIT 712 LINE SIZE 3/16" LINE LENGTH 25,000'

TOOLS USED 3½-5' BAR COLLAR LOCATOR TEMPERATURE NOISE

TOOL NUMBERS 4035

DIAMETER 1-3/8"

RESULTS AND REMARKS: NO INDICATION OF ANY GAS LEAKAGE.

**Figure 6: SS-25, Noise Log Header on July 27, 1984, "No Indication of Any Gas Leakage", 2,390 psi**

There is a supplementary report titled *SS-25 Temperature, Pressure, and Noise Logs Analysis* [26], and the focus of that report was to assess any evidence of any pre-existing casing integrity issue on SS-25. No temperature, pressure, or noise anomalies in the surveys indicated a preexisting casing failure before the October 23, 2015 incident [9, p. 31]. Casing shoe leaks (i.e., gas from storage zone traveling out of that zone behind casing) were not the focus – these types of leaks would not have any bearing on the corrosion and subsequent casing failure at 892 ft.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change. There were no indications of a preexisting casing integrity issue.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   No conclusion changes are needed.

## 2.20 Statement 20

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.

### 2.20.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   See the response to Statement 18 question 3.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change. There were no indications of a preexisting casing integrity issue.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.21 Statement 21

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.

### 2.21.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change. There were no indications of a preexisting casing integrity issue.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.22 Statement 22

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).

### 2.22.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change in the conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.23 Statement 23

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

### 2.23.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Agree.

2. If Blade disagrees with any portion of the statement, why?

   Not applicable. Blade agrees with the statement.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change in the conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.24 Statement 24

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.

### 2.24.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   In general, Blade agrees with this statement. Noise originating from surface was detected in some logs and this source of the noise was documented in the Results and Remarks section of the log.

2. If Blade disagrees with any portion of the statement, why?

   Blade disagrees with, "All logs measured generally shallow low frequency noise (200 to 600 Hz)." Some, but not all, logs have measured shallow noise.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change in the conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

## 2.25 Statement 25

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.

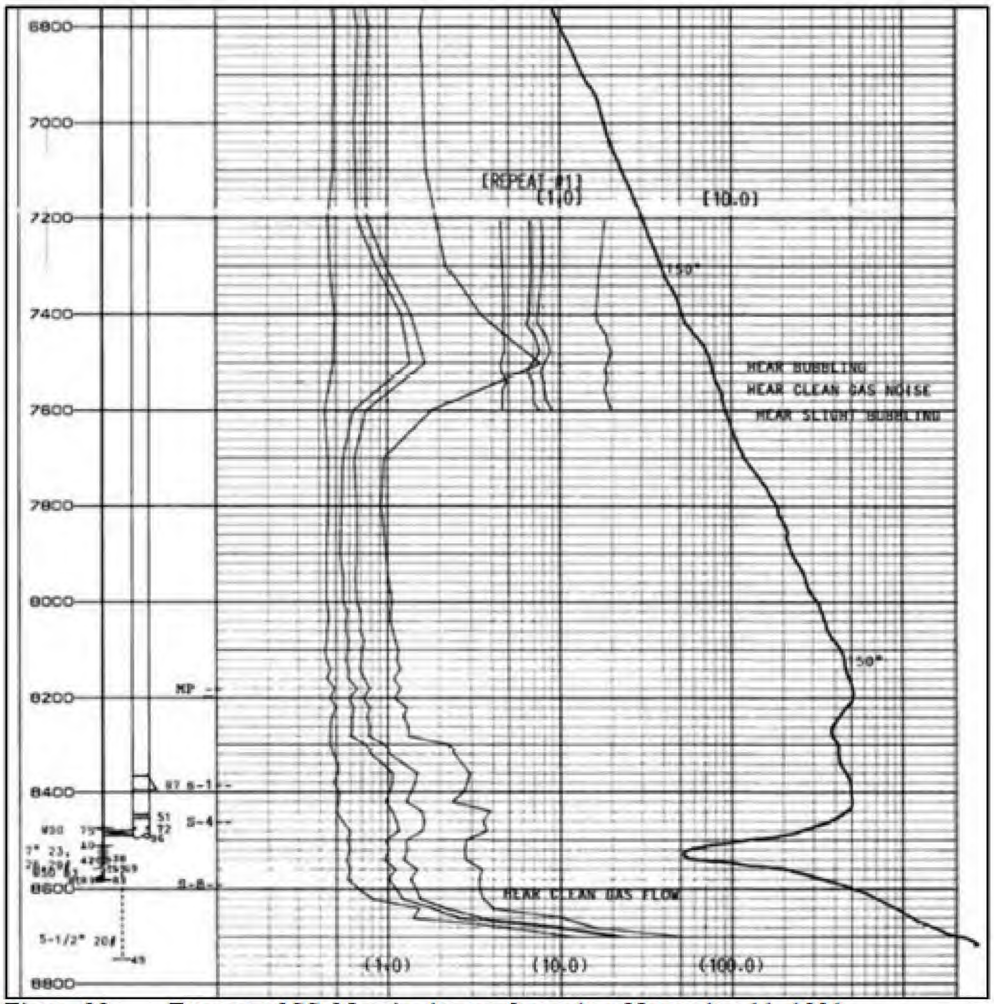


Figure 22. Excerpt of SS-25 noise log performed on November 11, 1991.

### 2.25.1 Blade Response

1. Does Blade Energy Partners agree or disagree with the statement?

   Disagree.

2. If Blade disagrees with any portion of the statement, why?

   Blade disagrees with "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." Not all the logs were run across the packer, completion equipment and storage formation. For example, in the December 8, 1978 log, the deepest observation point was approximately 7,900 ft, which is above the packer and storage formation.

   Blade agrees that in the repeat section from 7,200–7,800 ft bubbling noise was not detected.

3. Is there any context either in or outside of Mr. Carnahan's testimony that Blade wishes to add in order to explain its answers? If so, please provide it and explain.

   No.

4. If Blade accepts any part of the statement as true, does it change any of the conclusions Blade reached in its Root Cause Analysis?

   No change in the conclusions.

5. If the answer to question 3 is yes, which conclusions change and what must they say now?

   Not applicable. No conclusion changes are needed.

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