

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

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

**CHAPTER I**

**PREPARED SUR-REPLY TESTIMONY OF DANIEL NEVILLE ON BEHALF OF  
SOUTHERN CALIFORNIA GAS COMPANY  
(U 904 G)**

June 30, 2020

**TABLE OF CONTENTS**

I. INTRODUCTION.....1

II. MS. FELTS’ REASONS ARE UNSUPPORTED.....1

A. “Reason 1: SoCalGas’ Identified ‘Tubing Packer’ Completion Was of No Use when Boots & Coots Attempted to Kill Well SS-25.” .....1

B. “Reason 2: SoCalGas Falsely Claims that It Isolated Well SS-25 from Exposure to Groundwater.” .....2

C. “Reason 4: SoCalGas’s Did Not Show That Its Integrity Management Program Was Adequate Prior to the October 23, 2015 Well SS-25 Incident.”.....6

D. “Reason 5: SoCalGas Stated It Installed a Remote Well Kill System in Testimony But Did Not Explain in Response to SED’s Discovery Why It Did Not Use That Remote Well Kill System to Kill Well SS-25.” .....6

E. “Reason 6: SoCalGas Stated It Could Remotely Shut-In Wells to Prevent or Mitigate Leaks in the Wellhead or Surface Piping But Did Not Answer SED Discovery Asking Whether It Used Such Practices on Well SS-25.” .....7

F. “Reason 7: SoCalGas’s Statement that It Used Effective Leak Remediation Practices is Contradicted by Extensive Evidence.” .....8

G. Recordkeeping Related Reasons 8-14. ....9

H. “Reason 8: As A General Practice, SoCalGas Did Not Maintain Records of Daily Site Inspections.” .....10

I. “Reason 9: SoCalGas Used Lack of Anomalous Weekly Surface Pressure Readings as a Justification To Conduct No Further Related Investigations on SS-25.” .....10

J. “Reason 10: SoCalGas Provided Incomplete Monthly Well Site Inspection Records from 2006 to October 23, 2015, and No Monthly Well Inspections from 1973 to 2006” .....11

K. “Reason 11: SoCalGas Provided Incomplete Annual Leakage Survey Work Orders from 2006 to October 23, 2015, and No Annual Leakage Survey Records from 1973 to 2006.” .....12

L.	“Reason 12: SoCalGas Incorrectly Claimed that Annual Temperature Surveys, and Noise Surveys Were Sufficient to Monitor and Detect Leaks.” .....	13
M.	“Reason 13: SoCalGas Provided No Records of Pressure Gauge Readings from Before the Incident at Aliso Canyon.” .....	17
N.	“Reason 14: SoCalGas Provided No Records Showing Casing Integrity Inspections from 1973 to October 23, 2015.” .....	17
III.	CONCLUSION.....	18

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24

**CHAPTER I**

**PREPARED SUR-REPLY TESTIMONY OF DANIEL NEVILLE ON BEHALF OF  
SOUTHERN CALIFORNIA GAS COMPANY (U 904 G)**

**I. INTRODUCTION.**

The purpose of my prepared sur-reply testimony on behalf of Southern California Gas Company (SoCalGas) is to address the Reply Testimony submitted on behalf of the California Public Utilities Commission’s (Commission) Safety and Enforcement Division (SED) by its witness, Margaret Felts on March 20, 2020 (SED Reply Testimony). Specifically, I address the statements made by Ms. Felts in Reasons 1-14 cited by SED as supporting its argument that SoCalGas has not met its burden to show cause as to why the Commission should not find that SoCalGas violated Public Utilities Code § 451.<sup>1</sup> Each reason is refuted herein below for lack of factual support.

**II. MS. FELTS’ REASONS ARE UNSUPPORTED.**

A. “Reason 1: SoCalGas’ Identified ‘Tubing Packer’ Completion Was of No Use when Boots & Coots Attempted to Kill Well SS-25.”

Ms. Felts’ claim that the tubing packer completion was “of no use when Boots and Coots attempted to kill well SS-25”<sup>2</sup> is incorrect. Boots and Coots did in fact utilize the tubing string as a conduit to pump kill fluid in all kill attempts.<sup>3</sup> Although the kill attempts were not successful, the tubing packer completion served its intended purpose: providing a conduit for kill fluid. As I state in my opening testimony:

The tubing/packer completion provides two primary benefits: 1) a means to mechanically isolate the well from the storage zone through the use of a wireline-

---

<sup>1</sup> SED Reply Testimony (Felts) at 2-16, 19.

<sup>2</sup> Id. at 2-3.

<sup>3</sup> Blade Report (Main) at 144-153.

1 set downhole plug, and 2) a means to hydraulically isolate the well from the storage  
2 zone by providing a conduit for kill fluid.<sup>4</sup>

3 Ms. Felts' testimony ignores this purpose of the tubing packer completion.

4 To support her contention that the tubing packer completion was "of no use," Ms. Felts  
5 states that mechanical isolation was not appropriate, nor did SS-25 have plugs to allow  
6 mechanical isolation at the relevant times.<sup>5</sup> The relevance of these facts to the purpose of the  
7 tubing packer completion is unclear. Mechanical isolation using a wireline set downhole plug  
8 was not employed for any of the kill attempts by Boots and Coots; as Ms. Felts also  
9 acknowledges,<sup>6</sup> this method was not appropriate to isolate the well from the storage zone due to  
10 the nature of the leak. Boots & Coots employed hydraulic isolation for all kill attempts and,  
11 although isolation was not successful, the tubing packer completion did in fact provide a conduit  
12 to pump kill fluid from the surface to the storage zone within the inner tubing; i.e., the tubing  
13 packer completion served its purpose.

14  
15 B. "Reason 2: SoCalGas Falsely Claims that It Isolated Well SS-25 from  
16 Exposure to Groundwater."

17 Ms. Felts states, "Specifically, Mr. Neville misleadingly says that 'Well SS25 had 11-  
18 3/4" surface casing cemented to a depth of 990 feet, which provided the barrier between the fresh  
19 water sources and potential oil/gas zones at lower depths.'"<sup>7</sup> The alleged falsity perceived by  
20 Ms. Felts appears to be based on a misinterpretation of my opening testimony regarding the  
21 cementing the 11-3/4" surface casing to a depth of 990 feet. The purpose of the above statement  
22 was to describe the cemented surface casing as it provides a barrier between fresh water and  
23 potential oil/gas zones at lower depths.

---

<sup>4</sup> SoCalGas Opening Testimony Ch. I (Neville) at 1.

<sup>5</sup> SED Reply Testimony (Felts) at 2-3.

<sup>6</sup> Id.

<sup>7</sup> Id. at 3.

1 By virtue of having been drilled through groundwater, SS-25 could be expected to have  
2 exposure to groundwater, the exposure of which is the cemented 11-3/4” surface casing. The  
3 purpose of surface casing in SS-25 was for the protection of the groundwater by providing a  
4 barrier between fresh water sources and potential oil/gas zones at lower depths. In SS-25, this  
5 barrier consisted of the cemented 11-3/4” casing set to a depth of 990 feet, which encompassed  
6 the base of fresh water. “Reason 3: SoCalGas Did Not Sufficiently Pressure Test Well SS-25 to  
7 Operate it Safely.”

8  
9 Ms. Felts’ claim that SS-25 was not sufficiently pressure tested in 1973 is based on a  
10 misunderstanding of reservoir pressure as well as the process of pressure testing the casing  
11 utilizing workover fluids to replicate operational pressure in a gas environment. Ms. Felts states,  
12 “The 1973 test pressure was slightly above the 3150 psi operating pressure of the underground  
13 storage field at the time. However, the 1973 test pressure was also below the reservoir pressure  
14 of 3600, a pressure to which the well could be exposed.”<sup>8</sup>

15 Ms. Felts correctly notes the Aliso Canyon maximum reservoir pressure of 3600 psi,  
16 which is specified in the Project Approval Letter (PAL) issued by DOGGR. In her testimony,  
17 Ms. Felts notes the test pressure in the 1973 workover was 3400 psi, which she describes as  
18 “slightly above the 3150 psi operating pressure,”<sup>9</sup> and concludes the test pressure was  
19 insufficient because it was less than the reservoir pressure of 3600 psi.<sup>10</sup> When SS-25 is in  
20 operation however, its casing is in a gas environment and its maximum surface pressure is 3150  
21 psi while its bottom hole pressure is 3600 psi. The test pressure of 3400 psi is in fact sufficient  
22 for a surface pressure of 3150 psi.

---

<sup>8</sup> SED Reply Testimony (Felts) at 4.

<sup>9</sup> Id.

<sup>10</sup> Id. at 4-5.

1 The pressure tests conducted in 1973 at the time of conversion were conducted at test  
 2 pressures above the maximum pressures expected in the entire casing string during operations.  
 3 This was so because the 1973 pressure tests were conducted using workover fluid having a liquid  
 4 pressure gradient to replicate the operation of SS-25 having a gas pressure gradient. The  
 5 pressure testing conducted during the workover utilized a testing method referred to as “block  
 6 pressure testing,” a method by which packers and/or bridge plugs are used to divide the wellbore  
 7 into different depth segments. The depth segments account for the fact that a column of liquid  
 8 exerts more pressure at a given depth than a column of gas. A summary of the block pressure  
 9 tests from the 1973 workover is shown in Table 1 below.<sup>11</sup>

10 **Table 1**

8525' -surface	1500 psi for 23 minutes
6000' -surface	2000 psi for 25 minutes
4500' -surface	2400 psi for 25 minutes
3000' -surface	2800 psi for 27 minutes
2000' -surface	3100 psi for 25 minutes
1000' -surface	3400 psi for 33 minutes

11 The test pressure exerted at a particular depth is determined through a calculation  
 12 utilizing the liquid gradient. For example, the test pressure at surface is equal to the applied  
 13 pressure of 3400 psi. Accordingly, the test pressure at 1000 feet is equal to the applied pressure  
 14 of 3400 psi plus the hydrostatic pressure of 450 psi, or 3850 psi. Accordingly, the test pressure  
 15 at 8525 feet is equal to the applied pressure of 1500 psi plus the hydrostatic pressure of 3836 psi,  
 16 or 5336 psi.<sup>12</sup>

17 Ms. Felts further states the 1973 pressure test was insufficient based on a pump pressure  
 18 achieved by Boots & Coots during one of the kill attempts. She states, “The highest well kill  
 19 fluid injection pump pressure reached was 6500 psi during the Nov 6, 2015 kill attempt.”<sup>13</sup> She  
 20

<sup>11</sup> See SoCalGas Reply Testimony Ex. VII-2.

<sup>12</sup> Assumes typical salt water gradient of 0.45 psi/ft for workover fluid.

<sup>13</sup> SED Reply Testimony (Felts) at 5.

1 fails to account, however, that the pump pressure of 6500 psi achieved by Boot & Coots is  
2 irrelevant in that the pump pressure was applied to the inlet of the coiled tubing used to remove  
3 the hydrate plug prior to the kill attempt. The Boots & Coots November 6, 2015 activity report  
4 indicates the riser pressure was held between 2700 psi and 3000 psi.<sup>14</sup> The riser is attached to  
5 the top of the wellhead above the master valve, and thus the 2700 psi to 3000 psi represents the  
6 pressure inside of the tubing, not the casing, during the process of running the coiled tubing to  
7 clear the hydrate plug.

8 Finally, Ms. Felts argues:

9 In addition, prior to the failure of Well SS-25, SoCalGas had ordered new  
10 compressors that would boost the compression for injection gas to 3400 psi,  
11 essentially boosting the maximum operating pressure to 3400 psi and rendering the  
12 original 1973 pressure test for the casing inadequate.<sup>15</sup>  
13

14 SoCalGas was not planning to boost the maximum operating pressure at the wells to 3400  
15 psi. The referenced EIR document discusses the *capability* of the proposed new compressors and  
16 states the “maximum *discharge* pressure of the gas injected into the reservoir is approximately  
17 3400 pounds per square inch gauge.”<sup>16</sup> It is important to note that the discussion is in regard to  
18 maximum discharge pressure capability, where discharge pressure is measured at the  
19 compressors and some distance from the wells. Additionally, SoCalGas had no plans to inject  
20 above the CalGEM-approved reservoir pressure of 3600 psi, which equates to a surface operating  
21 pressure at the wells of approximately 3150 psi. Moreover, the new compressors were not in  
22 service at the time of the incident.  
23

---

<sup>14</sup> SED Reply Testimony (Felts), Bates No. SED\_RT\_0063.

<sup>15</sup> Id.

<sup>16</sup> SED Reply Testimony (Felts), Bates No. SED\_RT\_0064.

1 C. “Reason 4: SoCalGas’s Did Not Show That Its Integrity Management  
2 Program Was Adequate Prior to the October 23, 2015 Well SS-25  
3 Incident.”

4 Ms. Kitson responds to Ms. Felts’ Reason 4 in her sur-reply testimony (Chapter III). It  
5 seems necessary to clarify that the reference in my opening testimony to “[a]s of October 22,  
6 2015” means the practice was in place at that time, not that it commenced on that date. That is  
7 the date chosen for frame of reference because it is the day prior to the occurrence of the  
8 incident.

9 D. “Reason 5: SoCalGas Stated It Installed a Remote Well Kill System in  
10 Testimony But Did Not Explain in Response to SED’s Discovery Why It  
11 Did Not Use That Remote Well Kill System to Kill Well SS-25.”

12 The reason SoCalGas did not use the remote well kill system to kill SS-25 is because the  
13 wellhead was accessible for the connection of temporary piping, and thus the remote well kill  
14 system was not needed. Per my opening testimony:

15 As an additional safety measure, SoCalGas had in place a remote well kill system  
16 so that SoCalGas could kill the well *in the event the well site was inaccessible*. The  
17 system consisted of valves and piping connected to the wellhead, separate from the  
18 flow side of the wellhead, specifically to allow remote well kill. The piping ran to  
19 a remote area from the wellhead so that pumping equipment could be staged away  
20 from the immediate wellhead area, if necessary.<sup>17</sup>

21  
22 The remote kill system consists of permanently connected piping to the wellhead and, in  
23 the event unsafe conditions prevent access to the wellhead, provides a connection that is already  
24 in place. In the case of the SS-25 incident, the wellhead was accessible for the purpose of  
25 connecting temporary piping and thus the remote kill system was not needed.

26 Ms. Felts states that “SED also does not fully understand why Boots & Coots did not  
27 have access to the remote kill system, which would seem to be a good option to use when a rig

---

<sup>17</sup> SoCalGas Opening Testimony Ch. 1 (Neville) at 7 (emphasis added).

1 could not be safely moved over the well due to the desire not to ignite the gas streaming from the  
2 well.”<sup>18</sup> Boots & Coots did in fact have access to the remote well kill system, however, chose  
3 not to use the remote well kill system. The Boots & Coots October 30, 2015 activity report  
4 shows the tubing and casing kill laterals being removed and the wellhead being accessed.<sup>19</sup> In  
5 addition, well kills are conducted utilizing a pump truck located next to the well rather than a rig  
6 moved over the well.

7 Ms. Felts’ comparison to the P-44 incident, when the remote kill system was used, is  
8 inapposite.<sup>20</sup> That event involved a seal failure on a coiled tubing unit (specialized equipment  
9 for certain well work) and the wellhead was not accessible due to safety concerns.<sup>21</sup>

10 E. “Reason 6: SoCalGas Stated It Could Remotely Shut-In Wells to Prevent  
11 or Mitigate Leaks in the Wellhead or Surface Piping But Did Not Answer  
12 SED Discovery Asking Whether It Used Such Practices on Well SS-25.”

13 Ms. Felts states that “SoCalGas avoided answering the request for records of when these  
14 safety systems had been used to shut-in Well SS-25 by simply saying that it did not keep  
15 records.”<sup>22</sup> SoCalGas did not avoid answering the request, or even fail to answer the request;  
16 SoCalGas’ response was that such records are not kept. SoCalGas stated in the response to  
17 SED’s DR 47, “as a general practice, SoCalGas did not keep a record of instances when surface  
18 safety systems shut-in a well.”<sup>23</sup> Ms. Felts states this practice is “a failure in itself since such  
19 events have been indicative of leak events requiring some sort of operating response by  
20 SoCalGas and documentation.”<sup>24</sup> Per my opening testimony, safety systems were designed to

---

<sup>18</sup> SED Reply Testimony (Felts) at 7.

<sup>19</sup> SoCalGas Reply Testimony Ex. III-3, AC\_CPUC\_SED\_DR\_16\_0025636.

<sup>20</sup> The similarities cited by SED in response to SoCalGas Data Request 10 Question 2 are not factors that would warrant the use of the remote kill system. *See* Exhibit I-1.

<sup>21</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0112.

<sup>22</sup> SED Reply Testimony (Felts) at 8.

<sup>23</sup> *Id.* at 8, Bates SED\_RT\_0019.

<sup>24</sup> SED Reply Testimony (Felts) at 8.

1 shut-in the well to prevent or mitigate leaks in the wellhead or surface piping.<sup>25</sup> These safety  
2 systems could close for other reasons as well, either through loss of instrumentation pressure  
3 during normal operations or simply manually triggered prior to maintenance work on the surface  
4 piping. Consistent with this, leaks identified during daily or monthly inspections were input into  
5 Maximo as corrective workorders; the method of isolation, however, was not typically recorded.

6 F. “Reason 7: SoCalGas’s Statement that It Used Effective Leak  
7 Remediation Practices is Contradicted by Extensive Evidence.”

8 The term “leak remediation” in the context of my opening testimony is used to explain  
9 SoCalGas’ practices to identify leaks, mitigate leaks through isolation of the leak, and repair of  
10 the leak.<sup>26</sup>

11 Ms. Felts states the 2014 Storage Integrity Management Program (SIMP) Report on well  
12 FREW 2 was “*probably the most telling evidence proving the abject failure of SoCalGas’s leak*  
13 *detection and repair program.*”<sup>27</sup> Ms. Felts states that Frew 2 was not listed in the summary of  
14 casing leaks provided by SoCalGas to SED,<sup>28</sup> but that is so because Frew 2 did not have a casing  
15 leak. Indeed, Frew 2 had been converted to a tubing flow well in 1994, and thus was not at risk  
16 for a *casing* leak. The purpose of the SIMP program was precisely to identify wells that had wall  
17 loss as was found in Frew 2, the first well examined under the SIMP pilot. It is correct that  
18 temperature and noise surveys do not reveal casing wall loss. Temperature and noise surveys are  
19 not intended to reveal wall loss; these surveys are part of a monitoring program intended to  
20 *detect* leaks. Casing inspection logs such as USITs and HRVRT’s are intended to *monitor* for

---

<sup>25</sup> SoCalGas Opening Testimony Ch. I (Neville) at 8.

<sup>26</sup> SoCalGas Opening Testimony Ch. 1 (Neville) at 6-8.

<sup>27</sup> SED Reply Testimony (Felts) at 8.

<sup>28</sup> In DR 11 SoCalGas identified instances of casing, casing component, and casing shoe leaks, including method of mitigation and method of repair. SED Reply Testimony (Felts), Bates No. SED\_RT\_0167 (DR11.01 SoCalGas Leak Well List Master).

1 wall loss. SoCalGas conducted casing inspection logs on wells during workovers starting in  
2 2007, and SIMP was designed to conduct these logs on all wells as part of the program.

3 It is unclear why Ms. Felts takes issue with leak remediation utilizing casing patches,<sup>29</sup>  
4 which is an acceptable method of repair for certain leaks (see additional discussion in Chapter IV  
5 (Hower / Stinson), or why she suggests this was the only means of leak remediation employed by  
6 SoCalGas.<sup>30</sup> This is not true. Other leak remediation practices included remedial cementing,  
7 installation of inner casing strings, and plugging-and-abandonment of the well.

8 G. Recordkeeping Related Reasons 8-14.

9 In her testimony preceding Reasons 8-14, Ms. Felts refers to various “supporting”  
10 recordkeeping reasons. Her first supporting reason is related to her misunderstanding of when  
11 SoCalGas implemented the monitoring practices outlined in opening testimony. Ms. Felts uses  
12 the term “future practices noted by Neville,”<sup>31</sup> misunderstanding the fact that SoCalGas practices  
13 mentioned in opening testimony had been in place prior to the incident that occurred on October  
14 23, 2015, and not implemented the day before on October 22, 2015. Ms. Felts claims  
15 “recordkeeping for well SS-25 is surprisingly thin containing only 737 pages (through 2015)”  
16 and claims that “of these records 50% are receipts for work performed.”<sup>32</sup> I explain why this is  
17 irrelevant in my reply testimony, wherein I provide detail on the hard copy well file and its  
18 components, including Wellview, PI Historian, and Maximo.<sup>33</sup> I further explain well file size by  
19 noting “a comparison is improper given that well files can have different contents based on the  
20 number and type of reworks conducted on a particular well. Records do not exist for work that

---

<sup>29</sup> SED Reply Testimony (Felts) at 9-10.

<sup>30</sup> SED Reply Testimony (Felts) at 9-11.

<sup>31</sup> SED Reply Testimony (Felts) at 10.

<sup>32</sup> Id.

<sup>33</sup> SoCalGas Reply Testimony Ch. VII (Neville) at 2-10.

1 has not been done.”<sup>34</sup> As for the inclusion of invoices in the well file, they typically include  
2 information that is pertinent to know about the wireline work in the well, including details  
3 regarding the specific work performed on the well, such as the date of service, the type of  
4 service, and relevant findings.

5 H. “Reason 8: As A General Practice, SoCalGas Did Not Maintain Records  
6 of Daily Site Inspections.”

7 SoCalGas conducted daily site inspections to identify signs of abnormal operating  
8 conditions, such as odors or sounds. These daily inspections, or “rounds,” were not recorded;  
9 however, if follow-up was required, associated corrective workorders were created and  
10 maintained in the Maximo database. There are no regulatory requirements for daily site  
11 inspections.

12 I. “Reason 9: SoCalGas Used Lack of Anomalous Weekly Surface Pressure  
13 Readings as a Justification To Conduct No Further Related Investigations  
14 on SS-25.”

15 Ms. Felts states the weekly pressure readings “were not kept in any particular order or in  
16 one location.”<sup>35</sup> This is incorrect. SoCalGas maintained weekly pressure readings in an  
17 electronic database called PI Historian. As I explain in my reply testimony, “SoCalGas utilized  
18 PI Historian (PI) for collecting and maintaining operational data for the entire Aliso Canyon  
19 facility, including for the individual storage well.”<sup>36</sup> Weekly pressure readings were date  
20 stamped and maintained in the PI Historian database, and thus were both in order and in one  
21 location.

22 Ms. Felts states SoCalGas “could not conduct analysis or identify trends that could have  
23 helped SoCalGas evaluate the condition of Well SS-25.”<sup>37</sup> This also is incorrect. PI Historian

---

<sup>34</sup> Id. at 11.

<sup>35</sup> SED Reply Testimony (Felts) at 12.

<sup>36</sup> SoCalGas Reply Testimony Ch. VII (Neville) at 4.

<sup>37</sup> SED Reply Testimony (Felts) at 12.

1 provided a means to track or trend weekly well pressures. As I explain in my reply testimony,  
2 “PI provided users the opportunity to track or trend operating data over time. For example,  
3 weekly pressure of wells could be compared and plotted over time with PI.”<sup>38</sup> Thus, anomalous  
4 pressure readings could be investigated by trending the data. With respect to SS-25 particularly,  
5 as Ms. Felts notes, SoCalGas stated in a data request response that “[t]he weekly pressure  
6 records indicate that the surface pressure readings of [Well] SS-25 were not anomalous and  
7 consequently there was no reason for SoCalGas to conduct further investigations.”<sup>39</sup> Ms. Felts  
8 implies in her testimony that SoCalGas should have investigated non-anomalous well  
9 pressures.<sup>40</sup> She does not elaborate what types of investigations SoCalGas would conduct on  
10 non-anomalous surface pressure readings. An investigation necessarily requires a predicate  
11 incident.

12 J. “Reason 10: SoCalGas Provided Incomplete Monthly Well Site  
13 Inspection Records from 2006 to October 23, 2015, and No Monthly Well  
14 Inspections from 1973 to 2006”

15 SoCalGas’ practice at the time of the SS-25 incident was to utilize the Remarks section of  
16 the Maximo wellsite inspection workorder to record inspection results and to issue corrective  
17 workorders in the event an inspection required further maintenance. For example, the October  
18 2015 monthly wellhead inspection workorder, the Remarks state, “Inspection Complete, No  
19 Substandard Conditions.”<sup>41</sup> Also for example, as noted on the July 2015 monthly wellhead  
20 inspection workorder, the Remarks state, “MAXIMOS ISSUED: #5907370, #5907371,  
21 #5907372.”<sup>42</sup> The comments section of the Maximo workorder was not typically used and thus  
22 they were largely left blank. A blank comment section, therefore, does not necessarily indicate

---

<sup>38</sup> SoCalGas Reply Testimony Ch. VII (Neville) at 4.

<sup>39</sup> SED Reply Testimony (Felts) at 12.

<sup>40</sup> SED Reply Testimony (Felts) at 12.

<sup>41</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0485.

<sup>42</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0473.

1 that a workorder is incomplete Also, as the Job Plan in the work order indicates below in line 30,  
2 a follow-up workorder is required should substandard conditions be found:

3  
4 JOB PLAN NUMBER: AB1960-M-WELLS  
5 JOB PLAN DESCRIPTION: AB1960 MONTHLY PRODUCTION FACILITY/WELL INSPECTIONS  
6 JOB OPERATIONS:  
7 10 Inspect wells as follows:  
8 a. Verify that appropriate signage is in place and legible. b. For well cellars with existing floor or  
9 grating, verify that floor or grating is in good condition so as to exclude people and animals, as  
10 applicable. c. Verify that well cellars are free of standing liquids. If liquid is present in any cellar,  
11 remove it using a vacuum truck or pump it to an appropriate location. d. Verify that roads leading  
12 to the wells are safe and passable. e. Check for signs of leakage or spills, corrosion and weeds/  
13 debris.  
14 20 Notify your supervisor immediately if any substandard conditions are found.  
15 30 Create a follow-up work order for substandard conditions.  
16 40 Reference California Code of Regulations, Title 14, Division 2, Section 1777(c)(1).<sup>43</sup>  
17  
18

19 Regarding records that pre-date 2006, at the time of the incident, SoCalGas' records  
20 retention policy for monthly wellhead inspections was six years.

21 K. “Reason 11: SoCalGas Provided Incomplete Annual Leakage Survey  
22 Work Orders from 2006 to October 23, 2015, and No Annual Leakage  
23 Survey Records from 1973 to 2006.”

24 SoCalGas' practice at the time of the SS-25 incident was to utilize the Remarks section of  
25 the Maximo annual leakage survey workorder to record inspection results and to issue corrective  
26 workorders in the event an inspection required further maintenance. For example, the Remarks  
27 noted on the June 2006 annual leakage survey workorder state, “6/23/06 Completed. No sign of  
28 sub-surface lks.”<sup>44</sup> The comments section of the Maximo workorder was not typically used and  
29 thus they were largely left blank. A blank comment section, therefore, does not necessarily  
30 indicate that a workorder is incomplete.

31 Regarding records that pre-date 2006, at the time of the incident, SoCalGas' records  
32 retention policy for annual leakage surveys was six years.

33  
<sup>43</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0485.

<sup>44</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0489.

1 L. “Reason 12: SoCalGas Incorrectly Claimed that Annual Temperature  
2 Surveys, and Noise Surveys Were Sufficient to Monitor and Detect  
3 Leaks.”

4 As stated in my opening testimony, SoCalGas had in place a variety of practices for the  
5 monitoring of leaks, including daily well site inspections, weekly well pressure readings,  
6 monthly wellhead inspections, and annual temperature surveys. Noise logs and tracer surveys  
7 were conducted as additional investigative techniques for anomalies identified in temperature  
8 surveys. Temperature surveys were just one of the various practices employed to monitor for  
9 downhole leaks. The tubing/packer well design provided a means of isolating the storage  
10 reservoir from the wellbore either mechanically or hydrostatically in the event a leak was  
11 confirmed through one of the monitoring methods.

12 Ms. Felts appears to construe anomalies on temperature surveys as leaks. This is not  
13 always the case. An anomaly on a temperature survey *might* indicate a leak, and thus it was  
14 SoCalGas’ practice to investigate anomalies on temperature surveys. However, they were not  
15 always found to be leaks. Ms. Felts states the “1984 temperature/noise survey clearly shows a  
16 leak” and that “SoCalGas apparently did not investigate the leak any further. Instead it  
17 continued to run annual temperature surveys, and most of them continued to show the same  
18 leak.”<sup>45</sup> As mentioned in my opening testimony,<sup>46</sup> it was SoCalGas’ practice to investigate a  
19 temperature anomaly by conducting a noise log.<sup>47</sup> Thus, the temperature/noise survey on April  
20 11, 1984 was likely an investigation of a previous temperature anomaly. Remarks on the 1984  
21 temperature/noise survey did indicate the *possibility* of a small leak: “possible slight shoe

---

<sup>45</sup> SED Reply Testimony (Felts) at 13-14.

<sup>46</sup> SoCalGas Opening Testimony Ch. I (Neville) at 12-13.

<sup>47</sup> SoCalGas Opening Testimony Ch. I (Neville) at 6. Note that investigative noise logs include a temperature gradient.

1 leakage migrating higher than 8440' (Note temperature break around 6800 ft)."<sup>48</sup> SoCalGas  
2 continued to investigate by conducting an RA tracer survey on July 29, 1984. Remarks made on  
3 the RA tracer survey include: "possible slight leakage behind pipe from top perf at 8510' up to  
4 around 8430' and 8190'."<sup>49</sup> Remarks made on the July 1985 temperature survey conclude that  
5 there was no leak. "Temp anomaly similar to, but breaks slightly higher than surveys of past  
6 several years. Noise logs 7-84, 4-84, 2-83 and RA. 7-84 indicated no leak above S1."<sup>50</sup> Thus,  
7 SoCalGas did in fact investigate the temperature anomaly through the running of the 1983 and  
8 1984 noise logs, as well as the 1984 RA tracer survey. The type of leak being investigated at the  
9 time is known as a "shoe leak," which is a leak of storage gas around the bottom of the casing  
10 through the cement column, that manifests as a cooling anomaly within and above the top of the  
11 caprock area of the gas storage zone. The 1984 RA tracer survey, which looks for evidence of  
12 gas movement through introduction of a tracer element into the casing shoe area, confirmed that  
13 gas was not moving above the S1 sand which is within the caprock but considered to be open to  
14 the storage zone. Additionally, the noise logs run in 1991, 2006, and 2012 over the casing shoe  
15 confirmed again that gas was not moving around the casing shoe. In other words, the suspicion  
16 of the shoe leak was investigated and disproved.

17 Ms. Felts states there was a leak identified in the 1991 temperature and noise surveys. A  
18 review of the August 12, 1991 temperature survey includes the comments: "Cooling (straight  
19 line) from MP down to S1 depths (see attached detail). Plan NL."<sup>51</sup> These comments indicate a  
20 *possible* shoe leak and a plan to conduct further investigation of the temperature anomaly  
21 utilizing a noise log (i.e., NL). Indeed, a noise log was conducted on November 7, 1991, and

---

<sup>48</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0499.

<sup>49</sup> Ex. I-2.

<sup>50</sup> SED Opening Testimony, Bates SED 01639 – SED 01642.

<sup>51</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0500.

1 comments on the noise log were made on the 8/12/91 temperature survey as follows: “N/L of  
2 11/7/91 showed some noise activity to base of MP w/ temp break at top of MP. Probable small  
3 gas leak.”<sup>52</sup> The 11/7/91 noise log does not make conclusions concerning a shoe leak and states:  
4 “Heard distant noise above 1200’. At 500’ bled casing kill line on well 25A and heard even  
5 higher activity.”<sup>53</sup> These comments indicate that the noise at 1200’ was due to surface noise and  
6 not a well integrity issue. SoCalGas continued to monitor the shoe area by conducting the  
7 annual temperature surveys and additional noise logs in 2006 and 2012. Although a shoe leak  
8 may have been suspected, it was investigated and ultimately was not confirmed.

9 Ms. Felts states that “A temperature survey from 2000 shows the same shoe leak and also  
10 seems to indicate leakage in a range above 1000 ft.”<sup>54</sup> The temperature anomaly in the shoe area  
11 was similar to previous temperature surveys that had been subsequently investigated with noise  
12 logs and confirmed not to be shoe leaks. The temperature anomaly at 1000 feet is not typical of  
13 a casing leak. Leakage in the shallower section of the well, especially near the surface casing  
14 shoe, would be expected to manifest as pressure in the surface casing annulus. The surface  
15 casing annulus was monitored weekly by SoCalGas and did not show evidence of increasing  
16 pressure prior to October 23, 2015.

17 Ms. Felts states that the “2006 noise survey appears to show no leak, however, the quality  
18 of that one survey is suspect because the lines show no noise in the entire well, and appear to  
19 overlap each other at several points.”<sup>55</sup> A comparison of the 2006 noise log to the 1991 noise log  
20 does in fact indicate a quiet well in 2006. The 1991 noise log appears to pick up noise near the

---

<sup>52</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0501.

<sup>53</sup> Id.

<sup>54</sup> SED Reply Testimony (Felts) at 14.

<sup>55</sup> SED Reply Testimony (Felts) at 14.

1 surface as evidenced by the gradual increase in the low frequency (200 HZ) reading as the tool  
2 approaches the surface.<sup>56</sup> This increased reading or noise can be caused by factors such as  
3 wireline truck noise or gas flow in nearby surface piping. Comments on the 1991 noise log  
4 (“Heard distant noise above 1200’. At 500’ bled casing kill line on well 25A and heard even  
5 higher activity”<sup>57</sup>) does point to surface noise influencing the noise log. There are no comments  
6 on the 2006 noise log concerning surface noise.<sup>58</sup> It is possible that surface noise did not  
7 propagate down the well to be picked up by the noise tool in the 2006 noise log. The 1991 noise  
8 log indicates noise at the casing shoe, whereas the 2006 noise log is quiet at the casing shoe.  
9 Noise at the casing shoe can be attributed to gas flow within the storage zone or cross flow  
10 between different sands of the storage zone. Results from the 2006 noise log indicate there was  
11 not gas movement in the storage zone or cross flow between sands of the storage zone.

12 Although the lines of the 2006 noise log are very close and appear to overlap, the digital  
13 data in the log header shows there is separation in the readings with no overlap.

14 Ms. Felts states that “another temperature survey from 2007 shows the shoe leak and a  
15 clear indication of a shallow leak above 900 ft.”<sup>59</sup> Similar to the 2000 temperature survey, the  
16 temperature anomaly in the shoe area was similar to previous temperature surveys that had been  
17 subsequently investigated with noise logs and confirmed not to be shoe leaks. The temperature  
18 anomaly at 900 feet is not typical of a casing leak. Leakage in the shallower section of the well,  
19 especially near the surface casing shoe would be expected to manifest as pressure in the surface  
20 casing annulus. The surface casing annulus was monitored weekly by SoCalGas and did not  
21 show evidence of increasing pressure prior to October 23, 2015.

---

<sup>56</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0501.

<sup>57</sup> Id.

<sup>58</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0504.

<sup>59</sup> SED Reply Testimony (Felts) at 14.

1 Ms. Felts states, “The most recent temperature survey in the file is dated 2013, and it  
2 shows no evidence of leaks, which is remarkable since SoCalGas apparently did nothing to the  
3 well to repair leaks.”<sup>60</sup> Another explanation is that although there were temperature anomalies  
4 noted in the annual surveys, these anomalies were investigated, and not confirmed to be leaks.<sup>61</sup>

5 M. “Reason 13: SoCalGas Provided No Records of Pressure Gauge Readings  
6 from Before the Incident at Aliso Canyon.”

7 Ms. Felts has explained that she had trouble accessing some of the data provided by  
8 SoCalGas to SED.<sup>62</sup> This may explain why she includes this reason in her reply testimony.  
9 SoCalGas did in fact identify<sup>63</sup> pressure readings on SS-25 prior to October 23, 2015 in response  
10 to Question 2b of SED Data Request 47 dated November 27, 2019.<sup>64</sup> This claim is thus  
11 unsupported.

12 N. “Reason 14: SoCalGas Provided No Records Showing Casing Integrity  
13 Inspections from 1973 to October 23, 2015.”

14 My opening testimony regarding casing inspection discusses SoCalGas practices in place  
15 on October 23, 2015, when the SS-25 incident occurred. Casing inspections were conducted on  
16 wells undergoing workovers as part of a well integrity program that began in 2007, as described  
17 in further detail in SoCalGas’ Reply Testimony Chapter VI (Kitson):

18 In 2007, SoCalGas began a well integrity program to inspect, evaluate, and mitigate  
19 downhole well integrity issues. When working on a well (i.e., during a “re-work”),  
20 SoCalGas would replace the tubing, sealing element and wellhead valve, and would  
21 additionally inspect the casing. The inspection work included running ultrasonic  
22 inspection tools and pressure testing the well’s casing for integrity as warranted.

---

<sup>60</sup> SED Reply Testimony (Felts) at 14.

<sup>61</sup> Indeed, in response to SED’s data request, Blade stated, "As part of the RCA, Blade analyzed the historical temperature, pressure, and noise logs for SS-25. ... The conclusion was that there was no pre-existing 7 in. casing leak. Additionally, there were no physical observations from well inspections and weekly pressure measurements that indicated a pre-existing problem." Ex. IV-5 at 5-6.

<sup>62</sup> SoCalGas Reply Testimony Ex. I-10 (Tr. 97:12-13, 304:10-307:9 (Felts)).

<sup>63</sup> The documents were identified by Bates number because they had previously been provided to SED.

<sup>64</sup> SED Reply Testimony (Felts), Bates SED\_RT\_0004 – SED\_RT\_0008.

1 This well inspection and re-work initiative was the precursor to the formalized  
2 Storage Integrity Management Program (“SIMP”).<sup>65</sup>  
3

4 Casing inspection logs were not run during the 1976 and 1979 workovers of SS-25.

5 There were no workovers on SS-25 after those so there were no casing inspection logs and thus  
6 no records of casing inspection logs.

7 **III. CONCLUSION.**

8 For the reasons stated above, Ms. Felts’ Reasons 1-14 are unsupported.

9 This concludes my prepared sur-reply testimony.  
10

---

<sup>65</sup> SoCalGas Reply Testimony Ch. VI (Kitson) at 1-2.