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THE PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

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

Blade's response to SED-DR-078

San Francisco, California
March 24, 2021

Response to Data Request

Response to SED Data Request-78

Prepared for:

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CPUC Legal Division

Purpose:

Blade response to the CPUC Data Request SED 78 related to real time pressure monitoring, ground water, surface casing, cathodic protection, and risk assessment from the Reply Testimony of Mr. Tim Hower and Mr. Charlie Stinson on behalf of SoCalGas.

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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 April 15, 2020. Data Request No: SED 78 is related the Preliminary Investigation of Southern California Gas Company's Aliso Canyon Storage Facility.

The CPUC questions (from file: "I1906016 SED DR 78 Final.pdf") are included verbatim followed by the Blade responses to the questions.

The questions are related to the document titled: *Chapter I, Prepared Reply Testimony of Tim Hower and Charlie Stinson of MHA Petroleum Consultants on behalf of Southern California Gas Company (U 904 G)* (file name: "1_Ch. I - MHA - Hower and Stinson (A Final).pdf").

2 Questions and Responses

2.1 Question 1

1. Please refer to the following passage on pages 35 and 36.

   "SED's testimony regarding real time pressure monitoring ("RTPM") is unclear. At deposition, SED's witness clarified that the reason RTPM was important was that it could have enabled SoCalGas to identify and remediate the leak at SS-25, which she believes had been present for years at an earlier point in time. [Footnote omitted.] The facts, however, are otherwise: the leak and failure at SS-25 was a sudden event and there was no pre-existing leak. Ms. Felts testimony on this issue is also inconsistent with Blade's report. As such SED's contention here is simply without any factual basis or support." With this passage in mind, please answer the following:

2.1.1 Blade Responses

a. Does Blade agree that this passage can conclude that, "the leak and failure at SS-25 was a sudden event and there was no pre-existing leak."?

   Yes.

   Examination of the failed casing joint extracted from SS-25 during the Root Cause Analysis (RCA) indicated that the 7 in. casing failure was caused by external corrosion resulting in reduced casing wall thickness that bulged outward and ruptured in the axial (longitudinal) direction. The rupture was a sudden event caused by internal well pressure that exceeded the burst capacity of the reduced wall casing in a localized area of external corrosion. Following the axial rupture, gas expansion through the rupture caused localized cooling. The cooling caused the casing to become brittle and the 7 in. casing parted circumferentially leaving a gap between the upper and lower sections of casing. Both the axial rupture and the circumferential failure were sudden events that happened within a few hours of each other. Additional details regarding the two failure events are discussed in the Blade Main Report *Root Cause Analysis of the Uncontrolled Hydrocarbon Release from Aliso Canyon SS-25* [1, p. 3] and the Blade supplemental report *SS-25 Casing Failure Analysis* [2, pp. 73-77].

   Blade requested information related to when SoCalGas personnel last visited the SS-25 site before the leak on October 23, 2015. SoCalGas responded and provided details on the condition of the well and site prior to October 23, 2015 [3, p. 3]. The SoCalGas response stated the following:

   > The last visit to the SS25 pad before October 23, 2015 was on October 22, 2015 during the daily well inspection. The daily well inspection revealed no issues, no smell complaints were received, and the most recent weekly pressure readings indicated no anomalies. In addition, no wells in the immediate vicinity of the SS25 wellsite or the other two wells at the SS25 wellsite (SS25A and SS25B) showed elevated surface casing pressures or any unusual pressures from the previous days.

   As part of the RCA, Blade analyzed the historical temperature, pressure, and noise logs for SS-25. The details are included in the Blade supplemental report *SS-25 Temperature, Pressure, and Noise Logs Analysis* [4]. 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.

b. If not, why not?

Not applicable. Blade agrees that no pre-existing 7 in. casing leak existed.

c. In Blade's assessment, was there a pre-existing leak in well SS-25 prior to October 23, 2015?

No.

There were no data or evidence that indicated a pre-existing 7 in. casing leak in SS-25 prior to October 23, 2015.

d. If so, why?

Not applicable. Blade agrees that there was no pre-existing leak.

e. In Blade's assessment, can the possibility that there was a pre-existing 7 in. casing leak in well SS-25 prior to October 23, 2015 be ruled out?

Yes.

f. If so, why?

There were no data or evidence that indicated a pre-existing 7 in. casing leak in SS-25 prior to October 23, 2015.

g. If not, why not?

Not applicable. The data and evidence indicate there was no pre-existing 7 in. casing leak.

h. Provide additional context and documents as necessary to support these answers.

Included in the responses to Question 1 a, 1 c, and 1 f.

Additional context is provided in the document "*Blade Response to SED Data Request-58 Rev 1 05-15-2020.pdf*" in responses 17–25, which address logs, surveys, and the non-existence of historical casing leaks.

2.2 Question 2

2. Please refer to the following passage on page 36: "Ms. Felts also appears to be arguing separately that RTPM would have provided flow rate data that could have been utilized in the well kill. [Footnote 143] As a general matter, SED's allegations regarding real time pressure monitoring, and the Blade analysis on which it appears to be based, are highly speculative." Footnote 143 then references pages 270 through the beginning of 272 of Ms. Felts's deposition transcripts, which provide in part the following on pages 271 to 272:

"Q So what would a continuous real-time pressure monitoring system have provided that they couldn't have collected prior to the blowout?

A The way I connect this is that the real-time monitoring system would have probably prevented the blowout because they would have detected the leak at a lesser amount and shut in the well; so they would have had their readings at that point in time. But if they shut in the well, they wouldn't have to use the readings."

2.2.1 Blade Responses

a. In Blade's expert opinion, if a real-time monitoring system had been operational prior to October 23, 2015, could it have detected a leak in well SS-25 on October 23, 2015?

Yes, assuming that the word "leak" refers to the sudden rupture of the 7 in. casing on October 23, 2015.

Prior to the October 2015 incident, the monitoring program at Aliso Canyon was weekly manual surveillance of wellhead pressures. A real-time pressure monitoring system that included the tubing, tubing × production casing annulus, and production casing × surface casing annulus pressures could have been used to detect the changes in pressure in the tubing and annuli caused by a 7 in. casing rupture. The changes in pressure could have been evaluated and it could have been determined that a rupture had occurred. The changes in pressure would have been significant, indicating that the gas flow path had deviated from normal operations. In summary, the pressure data from the monitoring points could have been used to detect the rupture, to help diagnose the problem and to quantify the leak rate.

b. Would such a system likely have detected such a leak in well SS-25 prior to October 23, 2015?

Assuming the phrase "such a leak" means a 7 in. casing rupture with similar parameters as the one on October 23, 2015, data from a real-time pressure monitoring system could have been used to detect a 7 in. casing leak in well SS-25 occurring prior to October 23, 2015.

c. If Blade has experience with real-time monitoring systems, how would Blade describe their effectiveness with respect to detecting leaks?

Blades experience has been that these real-time monitoring systems are effective in detecting pressure excursions.

d. Please provide context to explain and documentation to support each answer as necessary.

See the responses to Question 2 a, 2 b, and 2 c.

2.3 Question 3

3. Please refer to the following passage on page 39.

"SED further alleges that if a SCADA system were installed, it would have provided insight into the size of the leak. Presumably, by the "size of the leak", SED (and Blade) mean the gas flow rate of the leak. But this is impossible. A SCADA system would have provided no information at all as to the magnitude of the gas leak. A SCADA system measures surface tubing and casing pressures and, if equipped with a well flow meter, the injection or production rate at the wellhead. At the time of the leak, the SS-25 well was injecting gas at a rate of approximately 70 MMscf per day. That is the rate that the SCADA system would have measured, and that rate has absolutely nothing to do with the magnitude of the downhole gas leak. Once the well was shut-in, the gas injection rate would now be zero, but the SCADA system would still not be measuring any flow rate associated with the gas leak because the SCADA system measures data at the wellhead. As the Blade report states, most of the gas from the leak would have "flowed through the heavily weathered and vertically fractured top 200-300 ft. of formation, however, some would have flowed horizontally through permeable or fractured layers away from the SS-25 well site, and some would have remained in the subsurface." It is not possible for a real-time measurement system at the wellhead to detect and measure the gas flow rate outside the wellhead flowing through the geologic strata.

The SED allegations in respect of SCADA are unfounded. SCADA on individual wells was not an industry standard in 2015 in gas storage fields developed in depleted oil and gas fields (80% of the U.S. gas storage fields). SCADA would not have yielded any useful information as to the location or extent of the gas leak in the SS-25 well. And, most importantly, a SCADA system would have made absolutely no difference in the events that transpired at the SS-25 well on October 23, 2015 and thereafter."

2.3.1 Blade Responses

a. In Blade's view, would a SCADA system have enabled the measurement of casing and tubing pressures below the SS-25 wellhead if it had been installed prior to October 23, 2015?

Yes.

b. If so, would the sorts of casing and tubing pressures that this SCADA system would have measured on well SS-25 enabled the operator to detect leaks on the well?

Yes.

A typical SCADA system collects well data, such as tubing and annulus pressures. A change in the tubing and casing pressures could be used by an operator as notification that something has changed at the well. Additional diagnoses of the well condition and pressures could be used to determine what caused the changes in pressure. Causes could include a leak in the surface equipment at the well or a downhole leak in the tubing or casing that changed the gas flow path.

c. Could real-time flow readings have been helpful in determining the flow rate of the leak at any time during the SS-25 111 days after the well failed?

No.

Blade interprets "*real-time flow readings*" as the gas flow rate from a device on the flow line to or from the well to measure the gas flow rate to the well while injecting or gas flow rate from the well while withdrawing gas. In a downhole leak scenario, the flowline would be shut-in and no flow would be measured to or from the well. The gas flow from the reservoir to the casing leak in SS-25 was escaping to shallow formations and to the atmosphere and therefore would not have been measured by a real-time gas flow measuring device on the flow line.

After the well failed, injection gas to the well was shut-in as stated in the response to a data request from Blade to SoCalGas [3, p. 1]. Therefore, if equipment to provide real-time flow reading had been available, it would have been disabled and isolated after the well failed and not helpful to determine the flow rate of the leak.

d. If so, please explain how the data could be used.

Not applicable. The gas leak flow rate would not have been measured with a flow rate measuring device on the flow line.

As discussed in the Blade Main Report [1, p. 230] a real-time pressure monitoring system could have provided immediate identification of the time of the SS-25 leak. At this point, the injection gas to the well could have been stopped and this could have prevented the brittle circumferential parting of the casing from occurring. The tubing and casing pressures could have been used to estimate the gas leak rate from the reservoir to the 7 in. casing leak as described in the Main Report [1, p. 132].

e. Are SCADA on individual wells an industry standard in gas storage fields developed in depleted oil and gas fields anytime post 2015?

Blade is not aware of an industry standard that requires SCADA for individual wells. Blade is aware of the requirement for a real-time data gathering system, such as Supervisory Control and Data

Acquisition (SCADA) for Underground Gas Storage wells in California that was a requirement to be employed by January 1, 2020 [5, p. 257].

2.4 Question 4

4. Please refer to page 21, and the passage that states: "Given that the purpose of the surface casing is to protect groundwater zones during the initial drilling and completion of the well, which was done in 1953 and 1954, and that the oversight of the surface casing operation was reviewed and approved by the DOGGR, there really is no reason for SoCalGas to have a "reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25" as is alleged by in the SED testimony".

   With this passage in mind, please answer the following:

2.4.1 Blade Responses

a. In Blade's assessment, should SoCalGas have had a reasonable understanding of groundwater depths relative to the surface casing shoe and production casing of well SS-25 prior to October 23, 2015?

   Yes.

   The SS-25 well architecture relied on a single barrier, namely the production casing, to maintain the well integrity. All threats to the integrity of the production casing should have been identified, evaluated, and mitigated. External corrosion resulting from groundwater exposure is such a threat. One way of identifying and evaluating this threat is a knowledge of the groundwater regime, including groundwater depths. Another way is to routinely inspect the production casing, which could have detected the external corrosion before it compromised the production casing. It is likely that the knowledge of the groundwater regime would have led to routine inspections of the production casing as a mitigation strategy, with the wall thickness reduction results serving as a factor to determine the inspection frequency. Groundwater locations identified from the SS-9 pad boreholes and logs are discussed in the Blade Main Report, Section 2.7 and Blade Supplementary Report, Volume 2, Aliso Canyon Field Hydrology.

b. If the answer is yes, in Blade's assessment, what sorts of safety consequences could have resulted from SoCalGas not having a reasonable understanding of the groundwater depths relative to the surface casing shoe and production casing of well SS-25?

   SoCalGas did not know the groundwater regime and, therefore, did not realize that groundwater exposure posed a threat to wellbore integrity.

c. Provide explanation and documentation as necessary to support your answers.

   Explanations are provided in responses to Question 4 a and 4 b above.

2.5 Question 5

5. Please refer to pages 21 and 22, and the passage that states, "Based on the historical data in the Aliso Canyon field, there was no reason for SoCalGas to anticipate there might be a potential problem with corrosion of the production casing at a depth above the surface casing shoe inside the annulus between the production casing and the surface casing, as occurred in the SS-25 well. Blade investigated the occurrences of shallow corrosion throughout the field. Regarding the 27 wells they identified that demonstrated shallow corrosion, Blade determined that almost all of the wells had

production casing external corrosion present below the surface casing shoe. Excluding the SS-25, only one well, P-50A, had production casing external corrosion above the surface casing shoe. [Footnote omitted.] Thus, corrosion on the production casing above the surface casing shoe was very rare. . . Knowledge of the hydrogeology and groundwater is only relevant for the design and implementation of the surface casing. [Footnote omitted]. With this in mind, please answer:

2.5.1 Blade Responses

a. Does Blade agree that, "Based on the historical data in the Aliso Canyon field, there was no reason for SoCalGas to anticipate there might be a potential problem with corrosion of the production casing at a depth above the surface casing shoe inside the annulus between the production casing and the surface casing, as occurred in the SS-25 well?

   Yes.

b. Why or why not?

   Although external casing corrosion was historically observed in Aliso Canyon wells, corrosion above casing shoe was observed only in P50A and SS-25 wells.

c. Is knowledge of hydrology and groundwater only relevant for the design and implementation of the surface casing?

   No, it is also relevant for the management of wellbore integrity.

d. Why or why not?

   Corrosion resulting from groundwater is a threat to wellbore integrity; therefore, knowledge and understanding of the groundwater behavior is necessary. The management of wellbore integrity needs to consider hydrology and groundwater.

   The SS-25 well used a single-barrier architecture, relying solely on the integrity of the production casing. In such single-barrier wells, the failure of the production casing will result in the loss of integrity of the well, as happened during the 2015 SS-25 incident. The evidence of shallow corrosion in the 27 wells (as referenced in the statement above) should have indicated that corrosion from groundwater was a factor threatening the wellbore integrity.

2.6 Question 6

6. Please refer to the following passage on pages 23 and 24, which states: "The Blade report also correctly points out that "[t]he function of the surface casing is to isolate fresh water sources and also provide a string for drilling the deeper hole for gas storage or oil production. The surface casing is not intended to provide any further barriers to gas or oil.[Footnote omitted.] "Thus, SoCalGas cannot be faulted for the condition of corrosion on the surface casing and any escaping gas through holes in the surface casing, which were caused post-leak, [Footnote omitted.] because the purpose and objective of surface casing is not to provide a barrier to gas or oil leaving the wellbore."

   With this passage in mind, please answer:

2.6.1 Blade Responses

a. Does Blade agree with the statement that the purpose and objective of surface casing is not to provide a barrier to gas or oil leaving the wellbore?

Yes.

b. If so, is this the only purpose and objective of surface casing with regards to safety?

As stated in Question 6, the purpose of surface casing is to isolate fresh water sources and to provide well control to safely drill the hole section below the surface casing. While drilling the hole section below the surface casing, the surface casing is used for well control with blowout preventer (BOP) equipment installed on the surface casing. The BOP and surface casing protect the rig personnel and surface equipment in the event of a well control situation by providing a method to shut the well in and safely remove the hydrocarbons from the wellbore. Once the gas and/or oil is safely removed from the wellbore, the drilling fluid hydrostatic pressure provides the primary well control barrier. The BOP and surface casing provide a secondary well control barrier for safety while drilling below the surface casing.

Once the production casing is set, the purpose of the surface casing is to isolate fresh water. The barrier to oil and gas is then provided by the production casing, cement, and wellhead equipment.

c. Provide context and explanation as well as documentation as necessary to support your answers.

See the Question 6 b response.

d. Would knowledge of corrosion on the surface casing provide the operator with any useful information related to the safety of the well?

Yes, assuming corrosion information on the surface casing can be obtained.

e. Why or why not?

Monitoring corrosion of the surface casing with the production casing in place is difficult with today's technology. There are no known quantitative corrosion evaluation tools available to reliably detect, monitor, and measure remaining wall thickness caused by corrosion of the surface casing. The production casing is inside the surface casing, isolating it, and preventing running casing inspection surveys directly in the surface casing.

Corrosion of surface casing is usually identified after the production casing is removed from the well. When the production casing is recovered, it exposes the surface casing and an inspection survey can be run in the surface casing to evaluate wall thickness and determine its condition.

When surface casing corrosion information is available, it can be used to determine if the corrosion is external or internal. External corrosion may indicate that corrosive conditions exist in the shallow zones and mitigation can be evaluated to protect future surface casing from metal loss in new wells that may be drilled in the area. Internal corrosion of the surface casing may indicate that corrosive conditions exist in the surface casing × production casing annulus and corrosion on the outside of the production casing is possible as was the case for the SS-25 production casing.

f. If so, what information would such knowledge have provided?

If the casing inspection survey showed reduced wall thickness of the surface casing because of corrosion, it should have resulted in the evaluation of nearby wells to determine if this had been a unique problem in one well or if there was reason to suspect the problem was more widespread in the field or an area in the field.

2.7 Question 7

7. Please refer to the Section entitled, “Cathodic Protection is not Industry Standard and Was Not Necessary for SS-25.” On pages 25 through 27.

2.7.1 Blade Responses

a. Note the passage in this section that states, “Cathodic protection can be an effective tool to prevent corrosion in shallow surface casing strings. While not an industry standard, the technology is used in some gas storage fields with known areas of high corrosion. Recall that, Aliso is not one of those areas: the Blade report documented finding no pattern of corrosion associated with well age, well location, or depth. Thus, given that the SS-25 well is not in a corrosion “hot spot,” the operator must balance the limited benefits of using cathodic protection to shield the surface casing versus the potential limitations and downsides.” With this in mind, please answer:

i. If Blade disagrees with how it has been characterized in this passage, please explain how and correct the characterizations.

Blade is not certain on what the pronoun “it” in question 7. a. i. refers to. We assume “it” refers to cathodic protection of the surface casing in the Blade responses.

Aliso Canyon wells did exhibit production casing corrosion according to casing inspection logs and the SoCalGas Rate Case testimonies. There were no data on the condition of the surface casing in the Rate Case testimonies.

ii. Even if there is no documented pattern of corrosion associated with corrosion, in Blade’s expert opinion, is this a valid justification for SoCalGas to not cathodically protect wells at Aliso Canyon natural gas storage facility?

If there is no pattern of corrosion then cathodic protection of the surface casing is not necessary.

iii. Why or why not?

In the absence of corrosion, the need for cathodic protection is not justified.

iv. In Blade’s assessment, was it possible for SoCalGas to forecast whether any of its wells at Aliso could be experiencing corrosion?

The issue of shallow corrosion on production casing and surface casing was summarized in the Blade Supplementary Reports titled “Aliso Canyon Shallow Corrosion Analysis” and “Aliso Canyon Surface Casing Evaluation”. Forecasting will require a corrosion study and that was discussed in the Blade Main Report.

v. If SoCalGas could have predicted corrosion on some or all wells, could SoCalGas have forecasted the severity of the corrosion for purposes of planning integrity assessments?

Surface casing cannot be easily logged as discussed previously in Question 6. e. Aliso Canyon had only four wells, in addition to SS-25, with surface casing logs. This discussion is summarized in the supplementary report titled “Aliso Canyon Surface Casing Evaluation”. Forecasting will require a corrosion study and that was discussed in the Blade Main Report.

vi. In Blade’s assessment, should the answers to questions 7.a.iv and 7.a.v factored into deciding whether to cathodically protect wells at Aliso in order to protect against corrosion that could evolve into leaks?

Yes, if surface casing corrosion was anticipated then cathodic protection system should have been considered.

vii. Provide context, explanation, and documentation as necessary to support your answers.

Refer to the responses provided in Question 7 a.

b. Note the passage in this section that states, “Similarly, within the areal ‘footprint’ of a cathodic protection system, all wells must be protected. The Aliso Canyon field is not only a gas storage field, but there are non-storage operations within the field boundaries accessing shallower hydrocarbon production. These shallow wells are not operated by SoCalGas. If SoCalGas were to install cathodic protection only on its gas storage wells, any shallow hydrocarbon wells operated by others at the field would suffer increased corrosion and loss of well integrity because of the cathodic protection currents.”

With this passage in mind, please answer the following:

i. Does Blade agree with the assertions in this passage?

Yes, Blade agrees. The interference of cathodic protection systems is well known in the industry, and unintended corrosion due to CP systems is not uncommon.

ii. In Blade’s view, is there any reason that Blade is aware of as to why all wells at Aliso Canyon natural gas storage facility could not have been successfully cathodically protected prior to October 23, 2015?

SoCalGas did employ cathodic protection systems for some wells in Aliso Canyon. The design intricacies of a cathodic protection system for all Aliso Canyon wells was beyond the scope of the RCA.

c. Note the passage in the section that states, “Cathodic protection typically works very well on protecting surface pipelines or shallow gas gathering lines, where the resistivity of the environment around the steel is known and relatively uniform. However, in the case of vertical surface casing which extends to a depth of approximately 1,000 feet, such as the SS-25 well, the resistivity of the soils can change suddenly and dramatically with variations in depth. This results in an extremely difficult engineering solution to design a cathodic protection scheme that accounts for the rapid changes in soil resistivity and balances the current applied in the cathodic protection system. When multiple wells are added to the equation, such as would be the case around the SS-25 well pad, the problem becomes increasingly more difficult and complex. Any imbalance in the applied current will have the undesired effect of increasing corrosion.”

i. Does Blade agree with the assertions in this passage?

Yes, designing a cathodic protection system for all wells is a complex process and requires detailed engineering.

ii. In Blade’s view, would it be possible and cost effective to design a cathodic protection scheme that accounts for the factors described in this passage in instances with multiple wells within close proximity of one another?

Designing a cathodic protection system for all wells is a complex process and requires detailed engineering to determine the feasibility and cost benefit.

iii. Provide context, explanation and documentation as necessary to support your answers.

See the responses to Question 7 c.

d. Note the passage in the section that states, Finally, the axial rupture of the production casing occurred at a depth of 892 feet, which was inside the surface casing of the well. The Blade report clearly states, "While a cathodic protection system would have provided corrosion protection to the 11 ¾ in. casing, it would not have protected the 7 in. casing inside the 11 ¾ in. casing." [Footnote omitted.] Thus, an independent corrosion protection mechanism like cathodic protection would not have been useful in this case, contrary to the suggestions made in the SED testimony. With this passage in mind, please answer:

i. Does Blade agree with the statements in this passage, including that cathodic protection would not have been useful in the case of protecting the 7 inch or 11 ¾ inch casing of well SS-25?

Yes, Blade agrees. A cathodic protection system could have prevented the external corrosion on the 11 ¾ in. casing. A cathodic protection system could not have prevented the 7 in. casing corrosion. This is discussed on Page 215 of the Blade Main Report.

ii. Please explain why or why not.

The production casing inside the surface casing from surface to 990 feet in SS-25 could not be protected with cathodic protection. The production casing was inside the surface casing, consequently any cathodic currents would have been shielded by the surface casing and would not have reached the production casing.

2.8 Question 8

8. On page 28, a passage states,

"Prior to 2007, SoCalGas did assess risk as part of ongoing operations, even if it was not documented as a formal risk assessment program; this was consistent with the standard practices of other operators." Footnote 115 at the end of this passage states, "See eg., Ex. I-62 (Testimony of Phillip E. Baker, Southern California Gas Company, 2016 General Rate Case, A.-14-11-004 at PEB-5 – PEB-8). Based upon this reference, please see the following passages from Ex.I-62.

In Ex. I-62, at PEB-5, a passage states, "While we have historically managed risk at our storage facilitated by relying on more traditional monitoring activities and identification of potential component failures, we believe that it is critical that we adopt a more proactive and in-depth approach. Historically, safety and risk considerations for wells and their associated valves and piping components have not been addressed in past rate cases to the same extent that distribution and transmission facilities have been under the Distribution and Transmission integrity management programs."

In Ex. I-62 at PEB-6, a passage states, "Currently, risk assessment of our storage system is of a qualitative nature and is based on our long experience in operating and managing SoCalGas ' storage facilities. During routine system assessments, we monitor the condition of our assets and consider the risks they may pose on safety, reliability, and the environment."

Please also refer to the passage on page 173 of the Blade Root Cause Analysis, indicating that SoCalGas made a recommendation in August 1988 to run casing inspection surveys and pressure test the casing in 20 Aliso Canyon wells used as casing flow wells [57] [58].[1] SS-25 was on the list of wells

[1] This question is not the same as question 2 because it asks about SoCalGas's self-described "long experience in operating SoCalGas' storage facilities", whereas question 2 asks about SoCalGas's self described "formal risk assessment program that began in 2007, or its implemented "Replace and Inspect" initiative". The bolding and underlining in this question are meant to highlight the different language.

and was considered a low priority well. Inspection surveys were run in seven of the 20 wells and included in all five high priority wells; five of the seven wells showed penetration of up to 60% in. Logs on two of the seven wells have not been located for review. Four of the five wells that [sic] showed numerous indications of wall loss above the surface casing shoe. Based on the high percentage of wells with significant penetration, the question remains as to why the remaining 13 wells were not inspected in the 2-year period as recommended. The Interoffice correspondence documents and additional details regarding the 20 wells are included in a separate report: *Review of the 1988 Candidate Wells for Casing Inspection* [59].

On pages 28 and 29, it states, "Second, starting in 2007 SoCalGas had a formal risk assessment program, which focused on wellbore integrity management. SoCalGas implemented a "Replace and Inspect" initiative, which included conducting wellbore integrity evaluations at Aliso Canyon and performing remedial work, if necessary, based on the results. SoCalGas implemented the initiative two years prior to Mr. Mansdorfer's 2009 recommendation for a similar initiative. The initiative included the inspection of the integrity of the production casing in the storage wells. Moreover, the "Replace and Inspect" initiative included detailed evaluations of the wellbore integrity and replacement of well hardware equipment, such as wellhead valves and the well tubing and packer. As a result of this initiative, SoCalGas permanently removed six wells, of approximately 30 wells inspected, from service based on their downhole condition."

With these passages in mind, please answer the following:

2.8.1 Blade Responses

a. In Blade's expert opinion, should SoCalGas's professed risk assessment pre-dating 2007 as part of ongoing operations and formal risk assessment program starting in 2007 have included those wells in the Interoffice correspondence documents and additional details regarding the 20 wells included in the report entitled "Review of the 1988 Candidate Wells for Casing Inspection"?

   Yes.

   A field wide risk assessment related to casing integrity should have included all Aliso Canyon field wells including the 1988 Candidate Wells for Casing Inspection [6, pp. 41-44] (AC_CPUC_0000063 – AC_CPUC_0000066). A risk assessment should have identified that the "casing flow wells of 1940s and 1950s vintage" were approximately 20 years older in 2007 with higher risks than in 1988. Blade interprets casing flow wells as wells that inject and/or withdraw via the production casing × tubing annulus. Wells completed as "casing flow wells" had no secondary barrier to contain the gas pressure if the primary production casing barrier failed. Wells with this type of completion design would be considered higher risk compared to wells completed with a primary and secondary barrier.

b. In Blade's expert opinion, should SoCalGas's professed risk assessment pre-dating 2007 as part of ongoing operations and formal risk assessment program starting in 2007 have prompted SoCalGas to inspect all of those wells in the "Review of the 1988 Candidate Wells for Casing Inspection" report?

   Yes.

   A risk assessment should have identified the casing flow wells of 1940s and 1950s candidate wells as wells needing to be inspected and pressure tested to determine the mechanical condition of the production casing as stated in the Interoffice Correspondence dated August 30, 1988 [6, pp. 41-44].

c. In Blade's expert opinion, should SoCalGas's professed risk assessment pre-dating 2007 as part of ongoing operations and formal risk assessment program starting in 2007 have prompted SoCalGas to take steps to address the metal loss identified on Aliso wells at the "Review of the 1988 Candidate Wells for Casing Inspection" report?

Yes.

The casing inspection technology post 2000 had evolved compared to 1988 technology. Improved inspection log technology could have been used to confirm the inspection log anomalies identified in the 1988 and 1989 logging program and to inspect additional wells.

d. If so, what steps should SoCalGas have taken?

The log and/or risk assessment results should have dictated the next steps.

e. Provide explanation, context and documentation as necessary to support your answers.

See the responses to Question 8 a, 8 b, 8 c, and 8 d.

Blade is not sure of the meaning of footnote 1 in Question 8, paragraph 4 and assumed the footnote was not relevant to the questions to Blade in this data request. The footnote refers to a Question 2, but Question 2 in this document appears to be related to a different subject than Question 8.

2.9 Question 9

9. Please note the following as context for the following question. Safety and Enforcement Division contends that Southern California Gas Company, as a natural gas operator regulated in the state of California, is required to follow the requirements provided under California Public Utilities Code Section 451. In particular, SED contends that Southern California Gas Company is required to follow the provision quoted here:

"Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities. . .as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

Accepting this as true for purposes of this question, please answer the following:

With regards to the reply testimony of Southern California Gas Company that was served on March 23, 2020, what additional concerns does Blade have with:

2.9.1 Blade Responses

a. SoCalGas's's[2] safe operation of its Aliso Canyon Natural gas storage facility prior to October 23, 2015?

Blade has no additional concerns.

b. SoCalGas's efforts to kill well SS-25 beginning on October 23, 2015?

Blade has no additional concerns.

[2] For purposes of this and all questions in discovery to Blade, reference to SoCalGas includes reference to Halliburton and Boots & Coots, as well as all other contractors SoCalGas hired to operate Aliso Canyon natural gas storage facility, and to kill well SS-25.

3 References

[1] Blade Energy Partners, "Root Cause Analysis of the Uncontrolled Hydrocarbon Release from Aliso Canyon SS-25," 2019.

[2] Blade Energy Partners, "SS-25 Casing Failure Analysis," 2019.

[3] SoCalGas, "Blade-Follow Up Request_82918_1.pdf," 2018.

[4] Blade Energy Partners, "SS-25 Temperature, Pressure, and Noise Logs Analysis," 2019.

[5] California Department of Conservation, "Statutes and Regulations, Geologic Energy Management Division," 2020.

[6] SoCalGas, "SS-25 Well Documentation (from SoCalGas)_N.pdf".