SED-281

Dynamic Solutions Report,

Aliso Canyon, SS25 (2-16-16)

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Report

SoCalGas

Dynamic Simulations

Aliso Canyon, SS25

SoCalGas

16 February, 2016

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Well Control & Blowout Support

Dynamic Simulations
Aliso Canyon, SS25

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ABSTRACT:

This report documents the transient simulations being performed in the response to the blowout occurring at the Aliso Canyon well SS25 on the 23rd of October 2015. Simulations and evaluations have been performed to history match the top kill attempts, diagnose the current conditions and plan for the upcoming relief well kill operation.

Simulations were performed using OLGA-WELL-KILL (powered by OLGA from Schlumberger). The simulator is tailor-made for well kill simulations and has been used in a number of on-site applications for blowout and well control since 1989.

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KEY WORDS:

Blowout simulations, Kill simulations, Relief well, Well control

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Summary

This report documents the simulations and evaluations performed in preparation to the relief well kill operation on the well Standard Sesnon 25 (SS25) on the Aliso Canyon gas storage field that was detected leaking on October 23rd, 2015.

A detailed dynamic Olga-Well-Kill network model was built, used and found to be a valuable tool for analyzing and understanding the transients occurring in the wellbore following the blowout. The model includes the 2 ⅞" tubing, the 7" casing, the 11 ¾" casing, packers and chokes. The fluids include the storage gas, water and various kill muds being used for the various kill attempts. All with thermodynamic properties varying with pressure and temperature. Prior to the relief well kill operation, a detailed model of the relief well was developed and included in the network with the SS25 well.

On October 23rd 2015, a leak was detected on the well SS25 that was shut-in at the time. Low pressure was monitored at surface on the 7" x 2 ⅞" annulus which is in communication with the reservoir through slots in the tubing down hole. If there was no leak, the surface pressure should have been 2450 psi, similar to the pressure readings on the two neighbor wells SS25A and SS25B. Simulations show that a surface pressure of 2450 psi equals a reservoir pressure of 3000 psi on October 23rd 2015.

Prior to the first kill attempt on October 24th 2015, the surface pressures read 1700 psi on the 2 ⅞" tubing, 290 psi on the 7" x 2 ⅞" annulus and 140 psi on the 11 ¾" x 7" annulus. The shut-in tubing pressure of 1700 psi equals a pressure of 2080 psi on the bottom of the tubing. Including the pressure drop through the piece of tubing down hole, the resulting drawdown of 740 psi from the reservoir at 3000 psi would result in a flow rate of 80 mmscf/d based on the provided reservoir productivity. (This estimated flow rate is not dependent of the flow path from the bottom of the tubing to surface, but only calculated based on pressures and the inflow performance relation (IPR) estimated from well tests).

Prior to the first kill attempt using a polymer pill on October 24th it is believed that there was a leak in the 7" casing allowing gas in the annulus between the 7" casing and the 2 ⅞" tubing to vent to the 11 ¾" x 7" annulus and further to surface. The flow path to surface could be through a leak at the wellhead but also outside the 11 ¾" casing set at 990 ft. The fracture pressure at the 11 ¾" shoe is less than 800 psi (15.6 ppg EMW) and the formation is not capable of holding the high pressure initially inside of the 7" casing. Pressure readings on the 11 ¾" x 7" annulus also confirm that the pressure reached 800 psi. The original drilling program from 1953 confirms a weak formation around the 11 ¾" shoe and it was documented that the cement job was done with severe losses. Based on this, it is suggested that the shoe fractured once being exposed to the initial high pressure from the 7" x 2 ⅞" annulus and that the flow path was outside of the 11 ¾" casing to the surface.

Prior to the kill attempts on October 24th 2015, it is believed that a restriction in the flow path was present causing gas expansion and Joule-Thomson cooling of the gas. Cold temperatures is also shown on the log from November 8th 2015.

Simulations show that unrestricted flow through the 7" x 2 ⅞" annulus would not cause as low temperatures as logged inside of the tubing. A restriction in the flow path would be required to reproduce the cold temperatures as observed. For example, simulations show that if the gas is bled down from 400 psi and 50 °F to 20 psi, it would get a temperature of 18 °F. A restriction in the flow path is supported by the temperature log run on November 8th, observations of cold wellhead, the large amounts of ice/hydrates on surface (on October 29th 2015) and the tubing got plugged once exposed to water in the polymer pill from the first kill attempt.

On October 24th 2015, 11 bbls of 10 ppg polymer pill was pumped down the tubing and the pressure increased to 3500 psig. 11 bbls pumped inside of the tubing yields a depth of 1948 ft. The conditions inside the tubing at this point were inside of the hydrate envelope, and a hydrate plug was formed and blocked off the tubing.

On October 24th 2015, following the pumping operation where the tubing got plugged, 89 bbl of 8.6 ppg brine was pumped down the annulus with no observed returns at surface. This is not consistent with high rate gas flow up the same annulus. In such a situation, the liquid would have been washed to surface in short time due to the high velocities of the gas. However, if the liquid flowed with the gas out to the annulus between the 11 ¾" casing and the 7" casing, the larger annular space could hold back the fluid in addition to fluid being trapped in fissures and crater outside of the 11 ¾" casing.

On October 28th 2015, liquid levels were monitored in the two annuli. In the annulus between the 11 ¾" casing and the 7" casing, the level was reported to be 43 ft. This information confirms a leak in the 7" tubing allowing brine to flow from the inner to the outer annulus. In the 7" x 2 ⅞" annulus, the level was 164 ft. Since liquid cannot sit on top of a gas filled void for a long period of time without falling through, it is believed that the levels measured on this date was due to ice or hydrates formed by the water being injected in the 7" x 2 ⅞" annulus and then flowed with the gas through the leak and to the outer annulus.

On October 29th 2015, significant amounts of ice or hydrates were observed on the fissures around the cellar of SS25. (This was prior to washing out the hydrate plug in the tubing on November 6th 2015). Cold temperatures in the wellbore was confirmed by the temperature log run on November 8th 2015 showing temperatures down to 19 °F. Based on the log, the temperature was below freezing at depths between 220 and 990 ft. In the annulus with low reported surface pressure, the temperature was below hydrate temperature down to 1150 ft. Inside of the tubing at higher pressure (1660 psi on November 8th), the temperature condition for stable hydrates would have been up to 66 °F. This temperature is estimated to be at 2200 ft from the November 8th log.

Blowout potentials have been calculated for various reservoir pressures and for the conditions in the wellbore prior to the kill operation. The unrestricted flow potential between the 7" casing and the 2 ⅞" tubing is 82 mmscf/d for a reservoir pressure of 3000 psi and 64 mmscf/d for a reservoir pressure of 2400 psi. For a reservoir pressure of 1000 psi, the blowout potential is 20 mmscf/d.

Analysis of the kill attempts that occurred between November 13th and November 25th 2015 with pumping down the 2 ⅞" tubing suggest that there is a leak in the tubing. The pump pressures observed during the pumping operations are lower than expected for fluid to be pumped down inside the 2 ⅞" (id = 2.411 in) pipe to the exit point at 8381 ft. The pressure drop from surface to the exit point would cause higher pump pressures than the pressures being reported. If the tubing on the other hand is not leaking or parted, the fluid exits the bottom of the tubing at almost zero pressure (estimated 100 psi) for the two last pump operations on November 24th and November 25th 2015.

On January 22nd 2016, a caliper log was run in the SS25 tubing between 3000 ft and 6000 ft, and no leaks in the tubing were detected for this interval.

Observations from a neighbor well being completed and exposed to the same reservoir sections indicate that there are limited losses even when the reservoir has been drawn down to around 1100 psia. The low pump pressure during the kill attempts on SS25 yield lower downhole pressures than the static down hole pressure in the neighbor well.

Relief well kill simulations were performed for the depleted reservoir pressure and showed that a low rate of kill fluid is required to kill the well. Various flow situations were covered prior to the final relief well kill operation were used to diagnose the situation during kill. They are included in the report for references in addition to the final kill operation being performed.

Conclusions:

The available information and simulations performed results suggest that the initial flow path was through the 7" x 2 ⅞" annulus, through a shallow hole in the 7" casing and to the 11 ¾" x 7" annulus. Data and simulations showed that the pressure in the outer annulus reached the fracture pressure of the 11 ¾" casing shoe with the consequence that flow paths were created outside of this casing to surface.

It is believed that initially there was a restriction in the flow path causing gas expansion and low temperatures in the wellbore at surface. As a result of low temperatures, hydrates were formed in the tubing and in both annuli after the pumping operation on October 24th 2015.

The initial flow rate assuming the flow path is through the 7" x 2 ⅞" annulus is estimated to be 80 mmscf/d. At the time of kill, on February 11th 2016, the flow rate was estimated to be 20 mmscf/d.

Simulations of the kill operations between November 13th and November 25th 2015 do not reproduce all the measured pressure data. The pump pressure on the tubing do not show an increasing trend as would be expected if mud started to flow with the gas towards surface and hence creating increased hydrostatic head and frictional pressure in the flow path. Also, the data from the pump operations show lower pump pressures than what would be expected for the provided rates.

Relief well kill simulations have showed that the blowout can be killed by pumping 9.0 ppg mud at 10 bpm from the relief well. At the time of intersection, the reservoir pressure is only 1150 psi and significant amount of losses are encountered. It is also a risk of not observing returns of mud at surface of SS25 due to fracturing and flow to large cavities close to surface. Therefore, pressure monitoring and comparison with simulated data was therefore utmost important in order to diagnose the kill operation.

The relief well kill operation on February 11th 2016 showed pressure responses in good agreement with the predicted from simulations. The operation confirmed that there were limited losses down hole during the pumping operation, and that the flow path was between the 7" casing and the 2 ⅞" tubing to surface. Further, the simulations confirmed that there is a leak in the 7" to the annulus between the 11 ¾" and the 7" and that the assumption of a fractured 11 ¾" shoe is consistent. Large cavities capable of taking larger volumes of fluid confirm that there were no visible returns of mud at surface after pumping 510 bbls of kill mud.

The final tubing head pressure settled out at 1400 psi and that indicates that mud is exiting the wellbore at a shallow depth and being trapped in cavities and craters.

Recommendations:

The relief well kill simulation on February 11th 2016 showed good agreement with the simulations being performed during the preparations to the final operation.

Although the simulations being performed served as a valuable source of information to gain better understanding of the incident and current condition in the wellbore prior to kill, there are still some mechanisms that could require more assessments to be fully understood. Recommendations for more work include verification of the provided data for the operations that were performed prior to the authors arrival at location. For example, the data on pressures, flow rates and choke sizes during the initial bleed downs to the test separator do not match with simulations. It is concluded that some of the provided data points are wrong.

The high flow rates of kill mud that were pumped down the 2 ⅞" tubing at much lower pressures than simulated is still not fully understood.

The simulation model can only reproduce the what actually happened if correct input data are used. Throughout the evaluation, it has been determined that some of the information provided is inaccurate and simulations will therefore not reproduce the provided results from these operations.

The kill operation was successfully accomplished and cement barriers have been placed in the wellbore. After potentially pulling the tubing and performing further investigations making more data available on the SS25 well, the final diagnostic can be confirmed and evaluated using the transient simulation model built during the operation.

1. Background Information and Input Data

1.1 General

Aliso Canyon is the second largest storage facility of its kind in the US with approximately 115 wells in total. The field was discovered in 1938 and produced oil and gas from the prolific reservoir until the field was converted to gas storage in 1974.

The blowout well, Standard Sesnon 25 (SS25), was drilled in 1953 and completed with a 2 ⅞" tubing. In 1979 a non-working downhole safety valve was removed which exposed seven 3" x ½" slots in the tubing creating communication with the A-annulus (between the tubing and the 7" casing). Gas production and injection was later being performed both through the tubing and through the annulus. On October 23rd 2015, a gas leak was detected at the surface near the wellhead through fissures in the ground. Over the next few days the flow concentrated around the wellhead eventually creating a crater estimated to be approximately 25 feet deep, 80 feet long and 30 feet wide.

1.2 Field location

The Standard Sesnon 25 well on the Aliso Canyon field is located just north of Porter Ranch, approximately 40 km north-east of downtown Los Angeles, California, see Figure 1.1. The map shows the exit point of the leak (SS25) and the spud location of the Relief Well 1 (P39A also known as RW1).

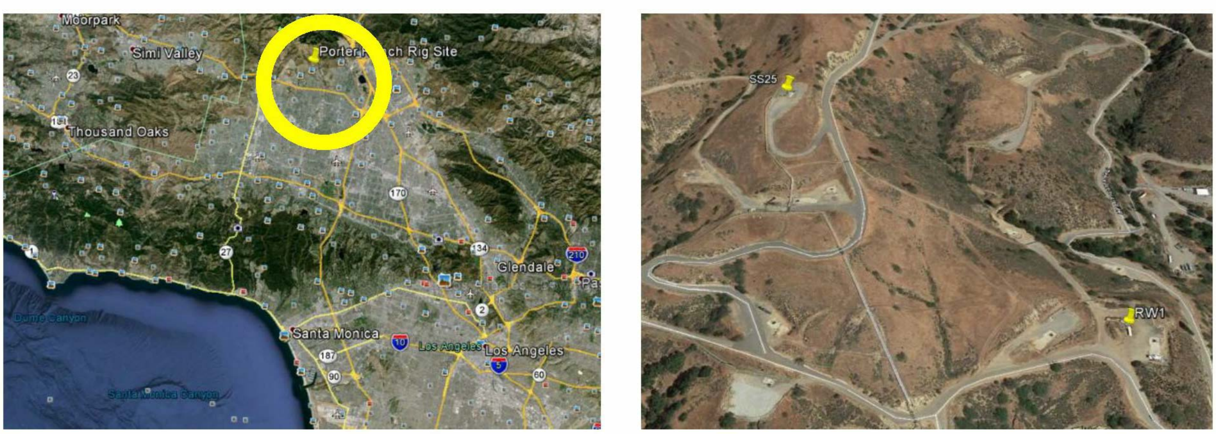

Figure 1.1: Location of well Standard Sesnon 25 and RW1

1.3 Spud locations and elevations

Relief well 1, RW1, is spudded 1480 ft from the SS25 well. The RKB of the RW1 is located 312 feet below the RKB reference of SS25 and 299 ft below the ground level and exit point at the SS25, see Figure 1.2. The RKB of RW2 that is also spudded as a contingency, is located 7 feet higher than the ground level of SS25.

Table 1.1: Spud locations and elevations

Well	X coord ft	Y coord ft	GPS coordinates		Horizontal Distance from SS25 [ft]	RKB elevation relative to SS25 rkb [ft]	RKB elevation relative to SS25 [ft]
SS25	6391345.315	1937526.673	34°18'54"N	118°33'51"W	0	0	0
RW1	6392496.384	1936596.112			1480	-312	-299
RW2	6391790.090	1938506.050			1076	-6	7

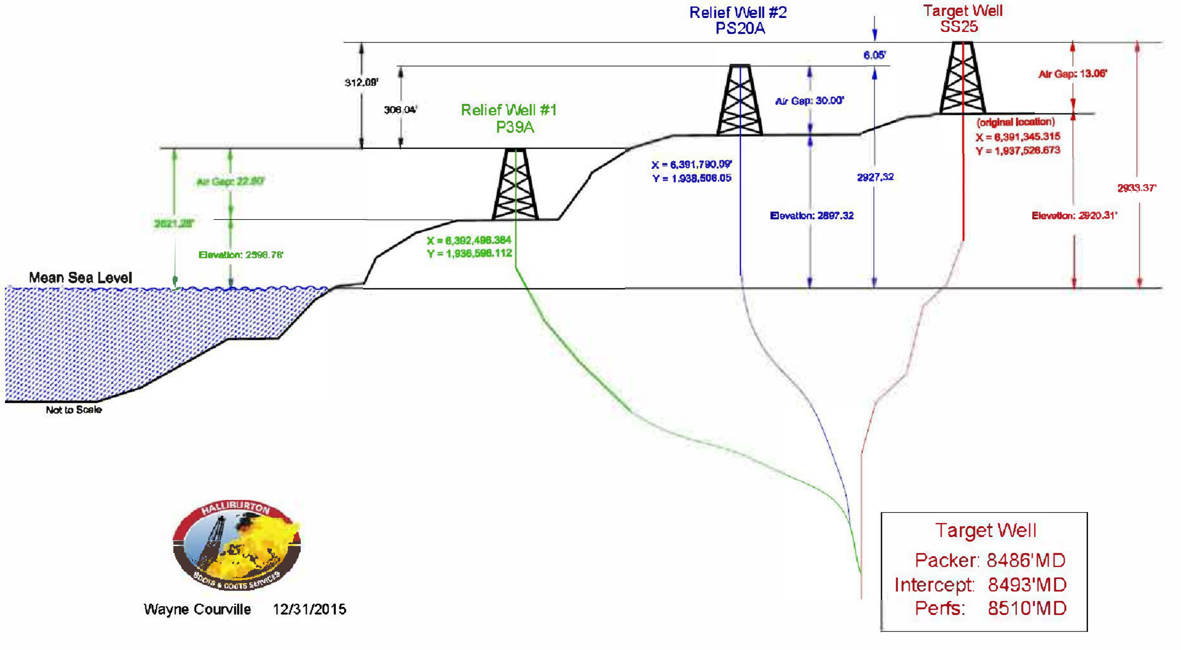

Figure 1.2: Well locations and elevations

1.4 Gas composition

The storage gas is mostly methane with a provided gas gravity of 0.63 sg. This is equivalent to a density of 0.0063 ppg (0.756 kg/Sm³) at standard conditions. A gas composition was assumed matching the specific density and is shown in Table 1.2.

This composition was characterized in PVTsim using the SRK-Peneloux equation of state to provide all required thermodynamic properties as functions of pressure and temperature. Some resulting gas densities are shown in Table 1.4.

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Table 1.2: Assumed gas composition SS25

Name	Symbol	Mole frac
Nitrogen	N_2	0.0
Carbon Dioxide	CO_2	1.0
Hydrogen Sulphide	H_2S	0.0
Methane	C_1	93.0
Ethane	C_2	4.0
Propane	C_3	1.0
i-Butane	Ic_4	0.5
n-Butane	nC_4	0.5
i-Pentane	iC5	0.0
n-Pentane	nC5	0.0
Hexanes	C6	0.0

Table 1.3: Gas densities at various pressure and temperatures

Gas densities in [ppg] for a range of pressures and temperatures						
Pressures [psi]	**Temperature [°F]**					
	60	**80**	**100**	**120**	**140**	**150**
14.5	0.006	0.006	0.006	0.006	0.005	0.005
500	0.230	0.219	0.209	0.200	0.192	0.188
1000	0.498	0.467	0.441	0.418	0.398	0.389
1500	0.797	0.738	0.690	0.649	0.614	0.598
2000	1.096	1.011	0.940	0.881	0.830	0.807
2500	1.365	1.263	1.176	1.101	1.037	1.008
3000	1.593	1.483	1.386	1.302	1.229	1.195

1.5 Well trajectory

The original well survey and the updated survey from January 16th 2016 (ran with continuous SDI keeper gyro) is shown in Figure 1.3.

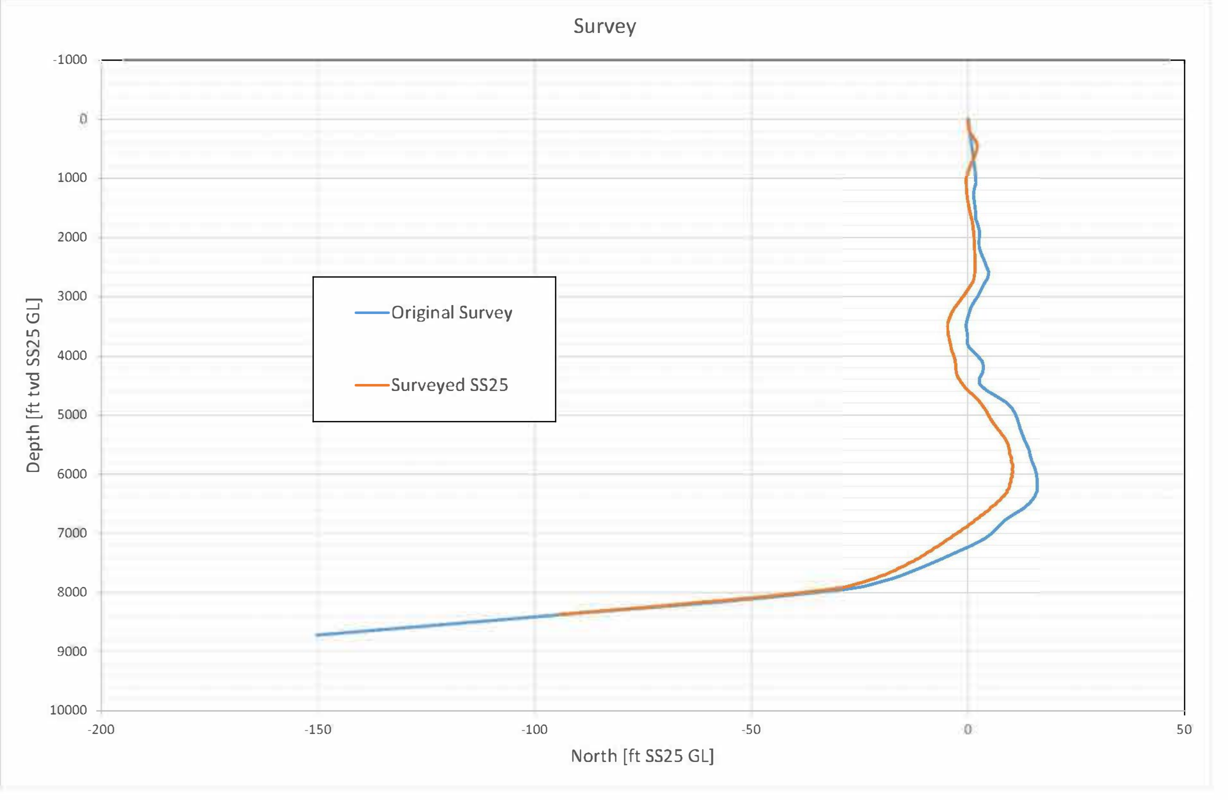

Figure 1.3: SS25 North – TVD

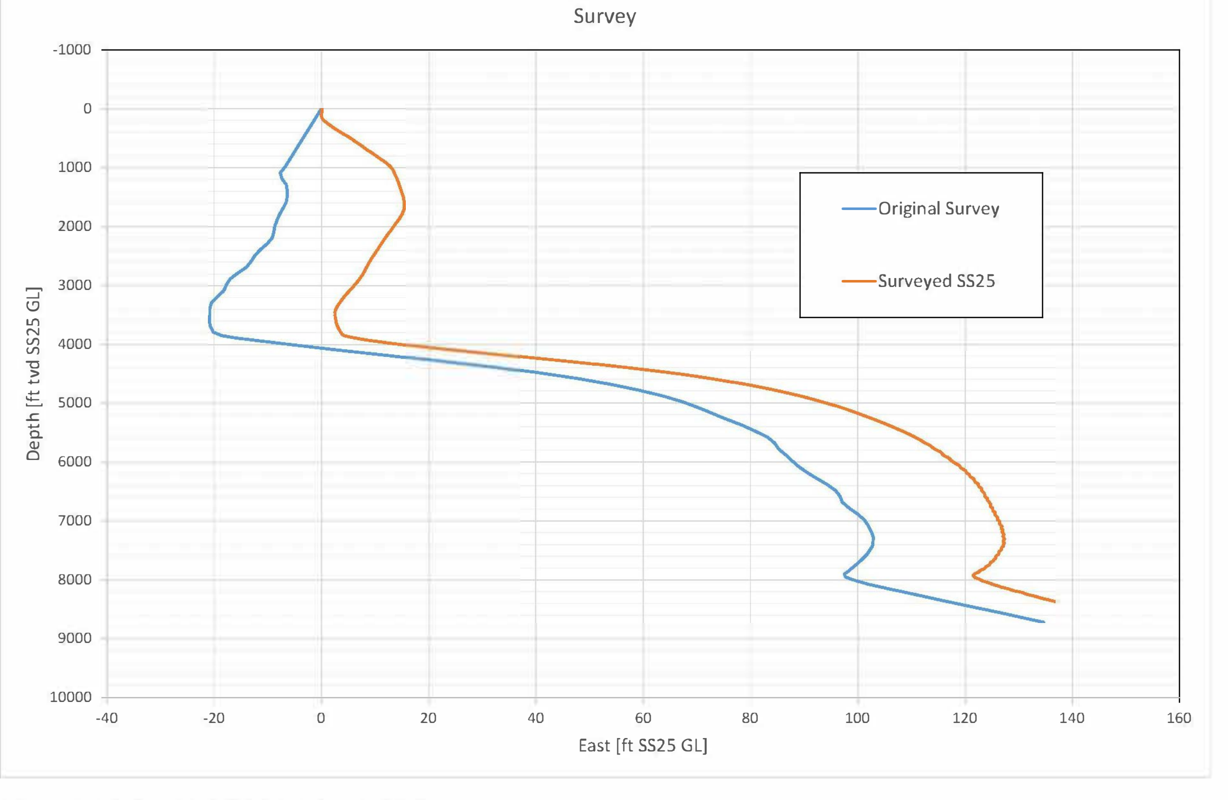

Figure 1.4: SS25 East – TVD

1.6 Reservoir data

The Sesnon Formation, located at depths from 7000 to 10000 ft is used to store natural gas on the Aliso Canyon field. The average minimum pressure in the spring before gas injection is in the order of 1500 to 2000 psi and the average maximum pressure in the fall before gas extraction is on the order of 3000 to 3500 psi.

Table 1.4 shows some key reservoir data for the gas sands. The production is believed to come from the sands S4, S6, S8, S10 and S12, and the properties and the total KH product (permeability times net pay) is shown in the table.

Table 1.4: Key reservoir data

Reservoir sand	Src	MD [ft]	SS [ft]	TVD [ft]	Thickness [ft]	Net sand [-]	Perm [mD]	KH [mD·ft]
S1	DK/IKONT	8 395	-5 451	8 384				
S2	SGC	8 434	-5 490	8 423				
S4	DK/IKONT	8 492	-5 547	8 480	12	10	149	1490
S6	DK/IKONT	8 509	-5 564	8 497	73	56	149	8344
S8	DK/IKONT	8 600	-5 653	8 586	22	17	83	1445
S10	SSI	8 628	-5 681	8 614	46	16	83	1360
S12	DALE/IKO	8 702	-5 754	8 687	18	6	83	510
S14	DALE/IKO	8 748	-5 799	8 732				
THZ	SCGC	8 749	-5 800	8 733				
Total					171	105		13149

1.7 Fracture pressure prognosis

According to the Aliso Canyon Geomechanical Analysis report (ref. 1), the fracture pressure gradient is 0.9 psi/ft. This yields a fracture pressure of 7650 psi (17.3 ppg) at 8500 ft.

Historically, on Aliso Canyon, a fracture gradient of 0.8 psi/ft has been used. This equals a fracture pressure of 6800 psi (15.4 ppg) at 8500 ft.

During drilling of RW1 (P39A) on January 27th 2016, a leak off test (LOT) was taken below the 7" liner shoe set at 8401 ft MD / 7956 ft tvd resulting in a fracture gradient of only 11.2 ppg. This equals 4625 psi or 0.58 psi/ft referenced RW1 and 0.56 psi/ft referenced SS25. See Figure 1.6.

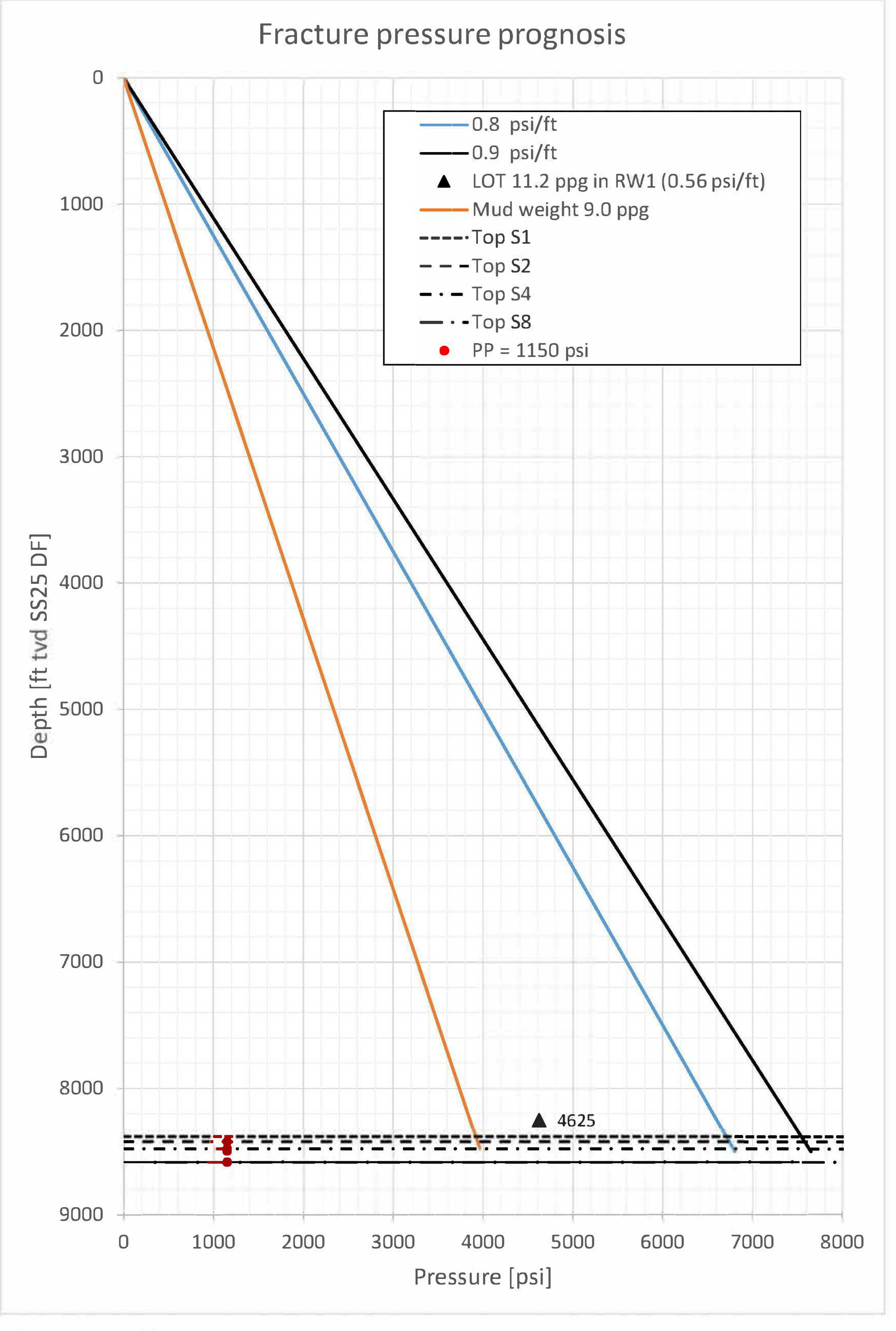

Figure 1.5: Fracture pressure prognosis

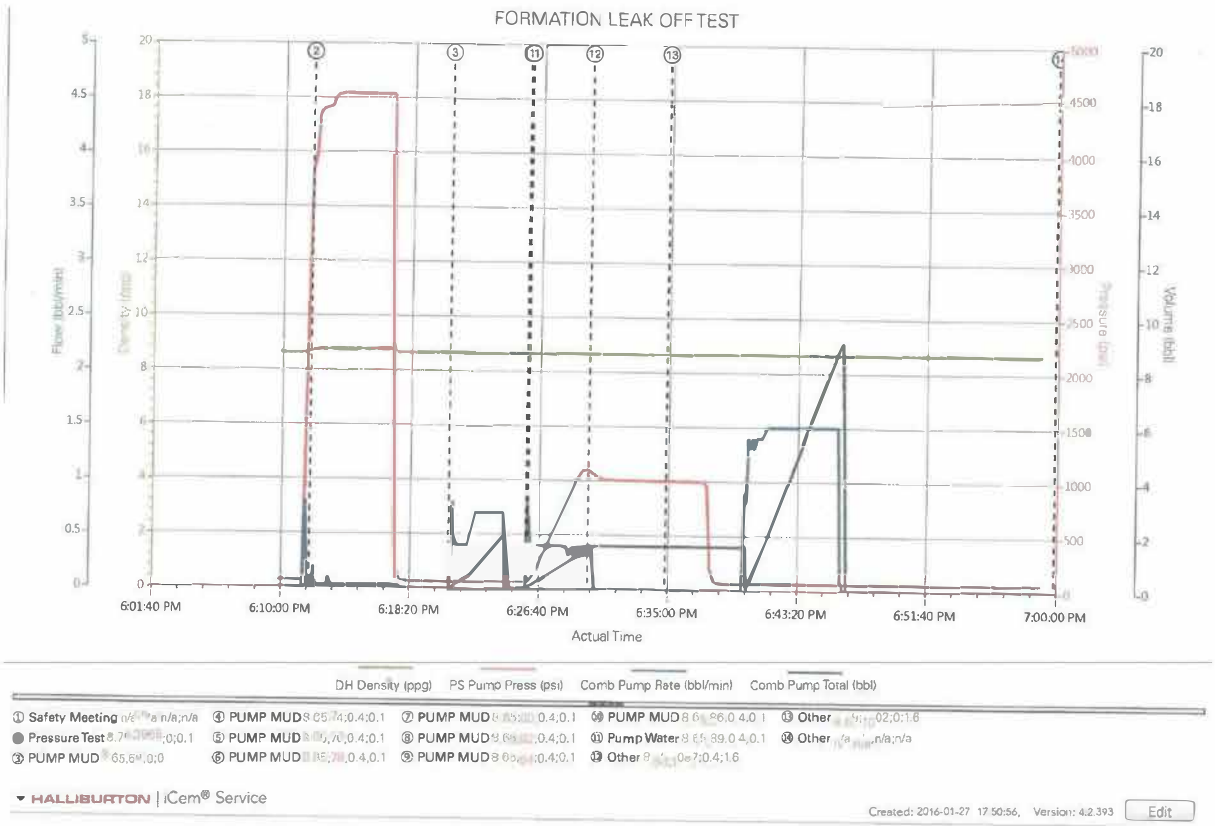

Figure 1.6: P39A 7" liner LOT data

1.8 Well configuration and casing design

Figure 1.7 shows a schematic of the wellbore. An 11 ¾" 42# casing is set at 990 ft MD. The 7" casing is set at 8585 ft. This is a tapered string with weights of 23, 26 and 29 lb/ft. The 2 ⅞" tubing goes down to 8496 ft. On October 12th 2015, an EZSV packer was set inside the tubing at 8393 ft MD. The tubing pressure was reported as 1694 psi, a negative pressure test was made on the tubing to confirm integrity by dropping the pressure to 1194 psi and left overnight. The next day the tubing pressure was holding at 1202 psi and was perforated between 8381 and 8391 ft, see Figure 1.8.

Details of the downhole completion and the current configuration at the bottom is shown in Figure 1.9.

Table 1.5: Dimensions of casing strings and tubing

	Weight lb/ft	OD in	ID in	Top ft	Bottom ft	Length ft
11 ¾" casing	42	11.75	11.084	0	990	990
7" casing	23	7	6.366	0	2398	2398
7" casing	26	7	6.276	2398	6308	3918
7" casing	29	7	6.184	6308	8585	2277
5 ½" slotted liner	20	5.5	4.778	8559	8749	190
2 ⅞" tubing	6.5	2.875	2.411	0	8496	8496

Table 1.6: Wellbore volumes

Flow conduit	Bottom [ft]	Top [ft]	Volume [bbl]
Volume below packer	8749	8486	9
Annulus between 2 ⅞" tbg and 7" casing from packer	8486	0	263
Volume between 7" casing and 11 ¾" casing	990	0	71
Volume inside 2 ⅞" tubing	8496	0	48
Volume outside of 7" casing to surface (10 ⅝" hole from TOC)	6725	0	427
Volume outside of 7" casing to surface (10 ⅝" hole)	8585	0	542

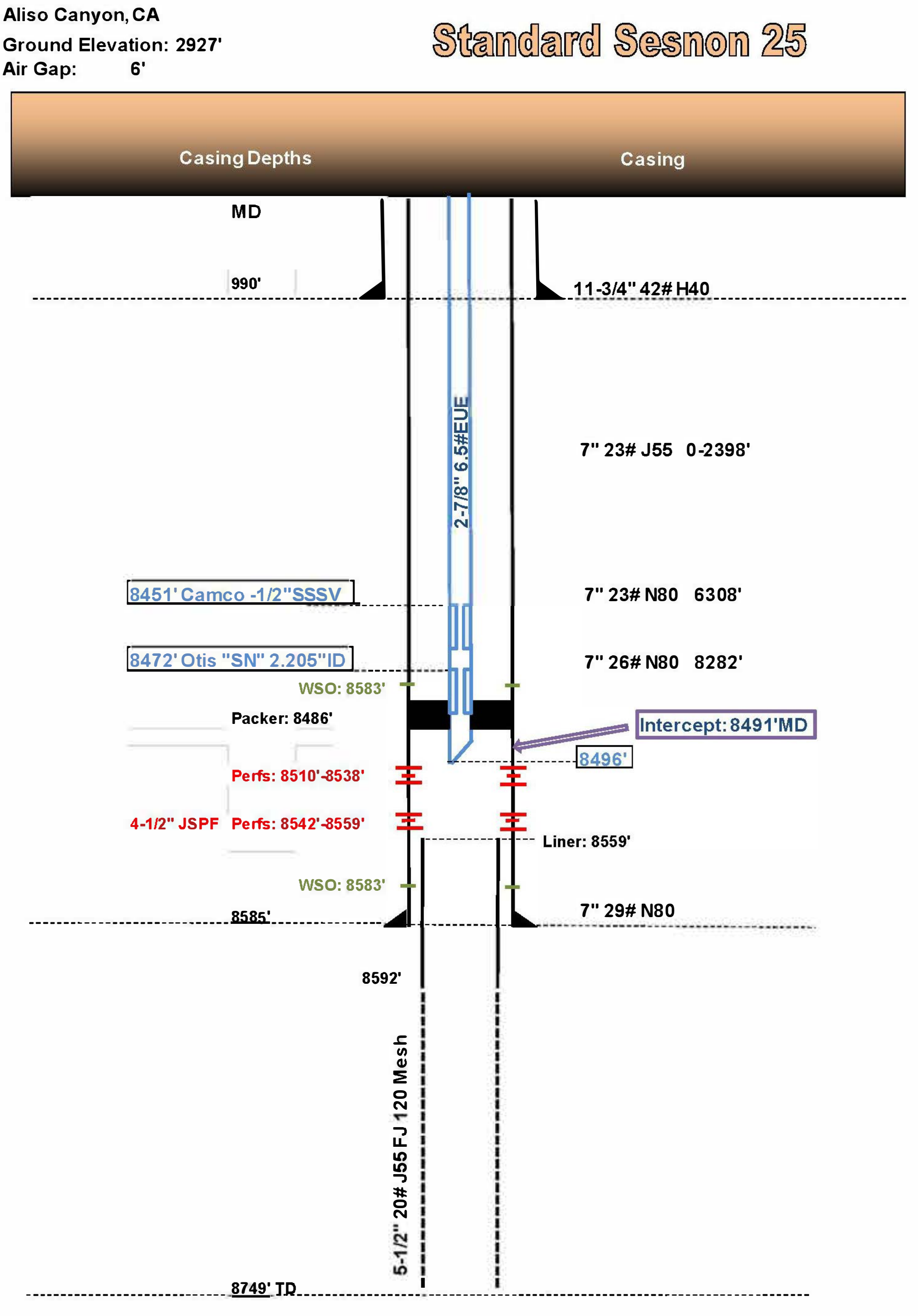

Figure 1.7: Wellbore schematic prior to perforation

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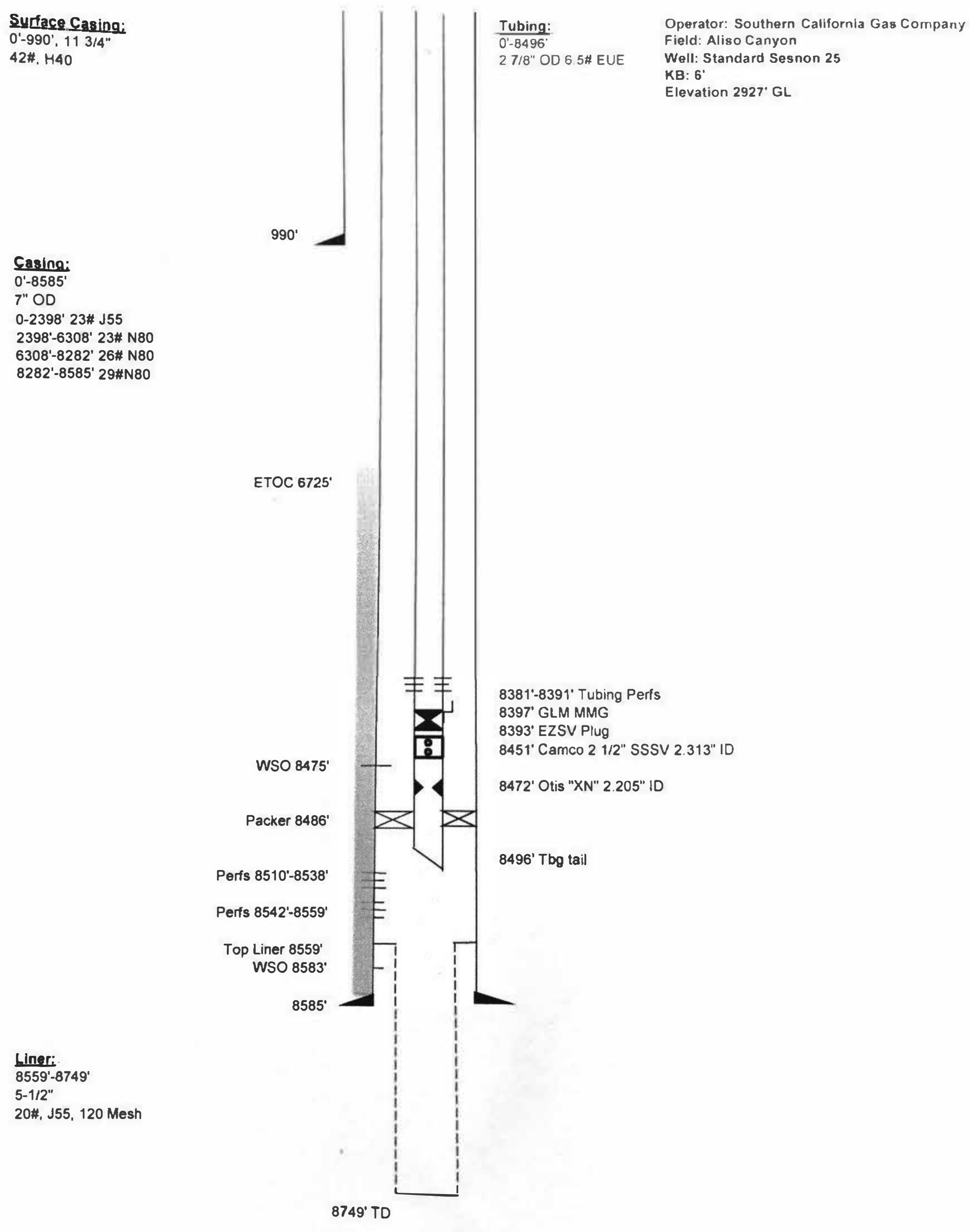

Figure 1.8: Wellbore schematic after tubing being perforated

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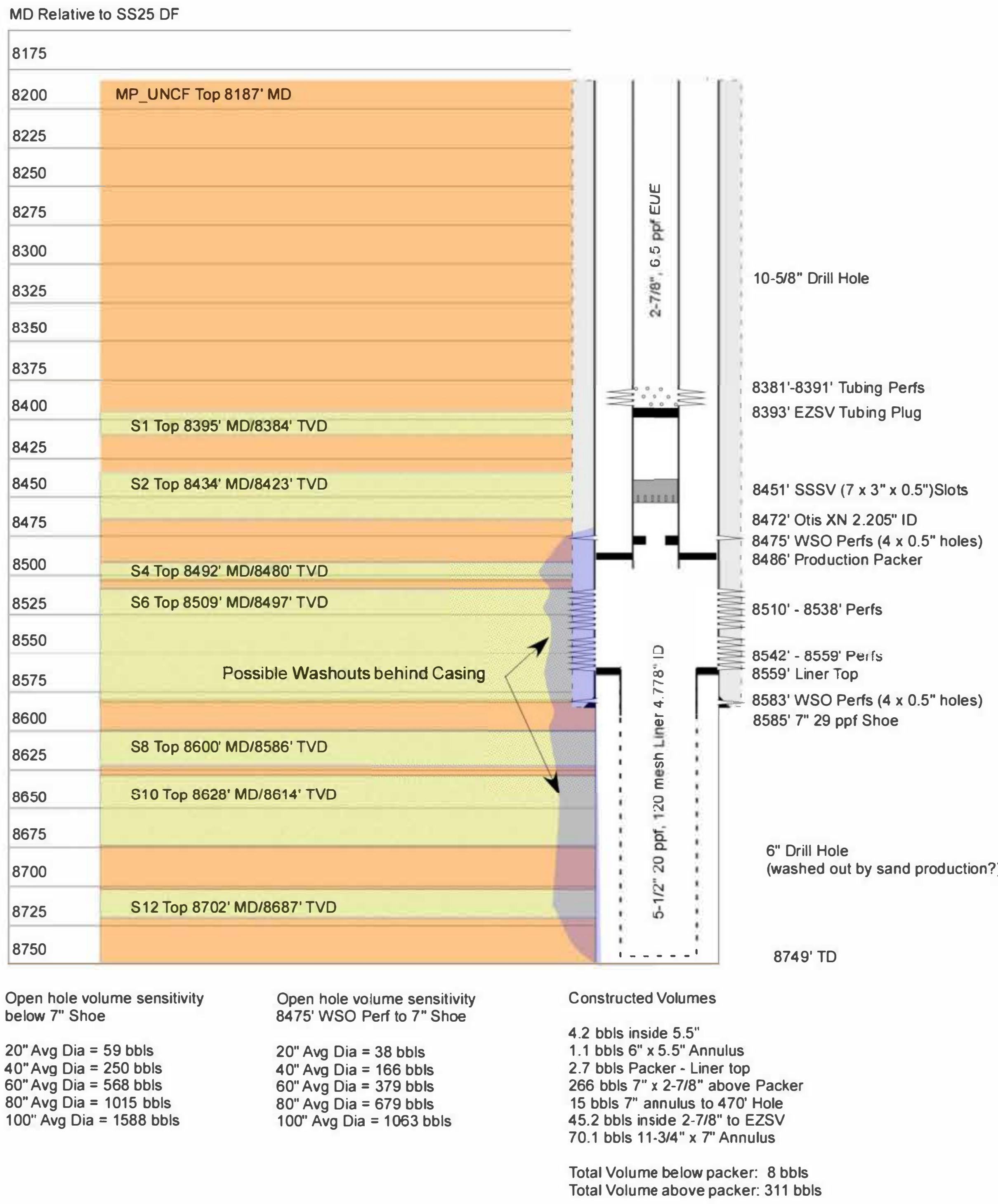

Figure 1.9: Details of the lower completion and reservoir sands

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2. Summary of observations and recorded pressures

On October 23rd 2015, a gas leak was detected on the SS25 well. The well had been on injection prior to the leak was detected. According to witness accounts, the SS25 sounded like it was still flowing after being shut-in after injection and it was noticed a gas odor on the east side of the well pad along the road at the location. The SS25 well had no anomalous pressure readings tubing/casing or surface casing prior to that day. No wells in the vicinity of the SS25 wellsite or the other two wells on the SS25 site (SS25A and SS25B) showed unusual pressures from the previous days.

On October 24th 2015, the primary and secondary wellhead seals were pressure tested to 1600 psig and they bled to 600 psig by a Cameron wellhead representative. Plastic was then injected into the primary seal cavity and tested to 2200 psi and held at 1800 psi. There was still audible noise at the wellhead with all the wellhead valves closed. Boots & Coots representatives later could find no evidence of flow across the wellhead seal assembly.

On October 24th 2015, with surface tubing pressure at 1700 psi, 11 bbls of 10 ppg polymer pill was pumped down the tubing and the pressure increased to 3500 psig. (11 bbls inside of the tubing yields a depth of 1948 ft). The pumps were then shut down. During the operation, the 7" casing pressure remained at 290 psig. This is an indication of no communication between the 2 ⅞" tubing and the 7" casing annulus.

After pumping down the 2 ⅞" tubing, it was decided to try to lubricate and bleed the 7" x 2 ⅞" annulus. Initially, 3 bpm was pumped with 290 psig casing pressure. The pressure on the 7" casing started to drop after 45 bbl of 8.6 ppg brine was pumped (45 bbl in the annulus equals a depth of 1436 ft). The pressure on the 7" production casing dropped to 250 psig.

The pump rate was increased to 4 bpm and the observed noise and vibration stopped. There were no observed returns. The pumping continued and after 89 bbl of brine was pumped into the annulus, additional gas flow was noted in cracks in the ground. The pumps were then shut and the well was monitored. Boots & Coots were called out after this and were involved in all future well operations.

On October 26th 2015, the 11 ¾" x 7" annulus was attempted bled down to the gas separator. The flow rate was reported to be 8 mmscf/d for 23/64" choke opening. The upstream choke pressure was 416 psi.

On October 27th 2015, the 7" x 2 ⅞" annulus was tried bled down to the gas separator. The flow rate was reported to be 3 mmscf/d for 11/64" choke opening. The upstream choke pressure was 275 psi.

On October 28th 2015, the wellhead pressure on SS25 was 170 psi on the tubing (which was plugged at the time), 128 psi on the 2 ⅞" x 7" annulus and 325 psi on the 7" x 11 ¾" annulus. A sample bailer was run in the tubing and detected solids at 467 ft. Polymer was found on the tool, the fluid level was estimated at 300 ft and the tool temperature was 47 °F. The well was shut-in but leaking. Fluid levels were also estimated in the annuli. The 11 ¾" x 7" showed 43 ft and the 7" x 2 ⅞" showed 164 ft.

On October 29th 2015, the shut-in pressure on the neighbor well SS25B was 2450 psi both on the tubing and on the annulus. This indicate a static reservoir pressure of 3000 psi based on shut-in simulations with gas in the tubing. Similar pressures would have been expected on the SS25 if it was shut-in and not leaking. Ice was observed on fissures around the cellar of SS25.

On October 30th 2015, the shut-in pressures was 823 psi on the 11 ¾" x 7" annulus. This is believed to be above or close to the fracture pressure of the formation below the 11 ¾" shoe at 990 ft. The pressure on the 7" x 2 ⅞" annulus was 614 psi. Witness accounts state that the gas rate from the fissures had decreased.

Between October 30th and November 6th 2015, the pressure on the 11 ¾" x 7" annulus decreased from 823 psi to 460 psi. The pressure on the 7" x 2 ⅞" annulus followed the same decreasing trend, see Figure 2.3.

On November 6th, a potential ice/hydrate plug sitting inside the 2 ⅞" tubing between 20 ft and 188 ft was washed out using coil tubing. With the washing assembly at 482 ft, the pressure decreased and returns were lost. After the ice/hydrate plug was washed out of the tubing, approximately 200 bbl of fluid were pumped and lost down hole. The gas activity on the fissures increased after the washing operation according to daily reports. After this date, the tubing pressure increased and varied between 1550 and 1700 psi. During the washing operation, the 7" x 2 ⅞" pressure dropped to 200 psi and the 11 ¾" x 7" pressure dropped to 60 psi, see Figure 2.3.

On November 13th 2015, the 2 ⅞" tubing was perforated between 8381 and 8391 ft after the EZSV was set at 8393 ft and the tubing negative pressure tested for integrity. Between 11:15 and 14:00 hrs, the tubing pressure was recorded to be 1526 psi and the 7" pressure was 253 psi. The following days, several kill attempts were performed without success.

On the same day as the 2 ⅞" tubing was perforated, on November 13th 2015, a junk shot was pumped down the 7" x 2 ⅞" annulus. After only 5 bbls were pumped, brine was observed from fissures and indicate a shallow hole in the 7" casing to the outer annulus between the 11 ¾" casing and 7" casing.

Since December 12th, the recorded tubing pressure on SS25 has followed a linear decline at a rate of approximately 28 psi/day, see Figure 2.3. Similarly, the recorded decline in tubing pressure for the neighbor well follows the same trend.

On December 30th 2015, pressure readings performed on the SS5 (another well in the same reservoir) well showed a tubing pressure of 1423 psi and a bottomhole pressure of 1759 psi.

On January 12th 2016, the pressure on SS5 was 1099 psi on the tubing and 1327 psi on the bottom.

The pressure difference between the static SS5 and the flowing SS25 is 370 psi on the tubing and 480 psi on the bottom on December 30th 2015. On January 12th 2016, the difference in pressure is 340 psi on the tubing and 410 psi on the bottom.

On December 30th 2015, the estimated flowing bottomhole pressure on SS25 is 1282 psi.

On January 12th 2016, the estimated flowing bottomhole pressure is 920 psi.

On January 26th 2016, the static reservoir pressure is 1150 psi and the pressure will not be drawn down further by producing through other wells. According to the drawdown and the estimated IPR, the gas flow rates are estimated to be 30 mmscf/d on December 30th, 2015 and 20 mmscf/d from January 12th 2016.

On February 11th 2016, the SS25 well was killed by pumping kill mud down the relief well P39A. The operation went just according to plan, and the pressure trends and final settle out tubing pressure of 1400 psi was in good agreement with the predicted.

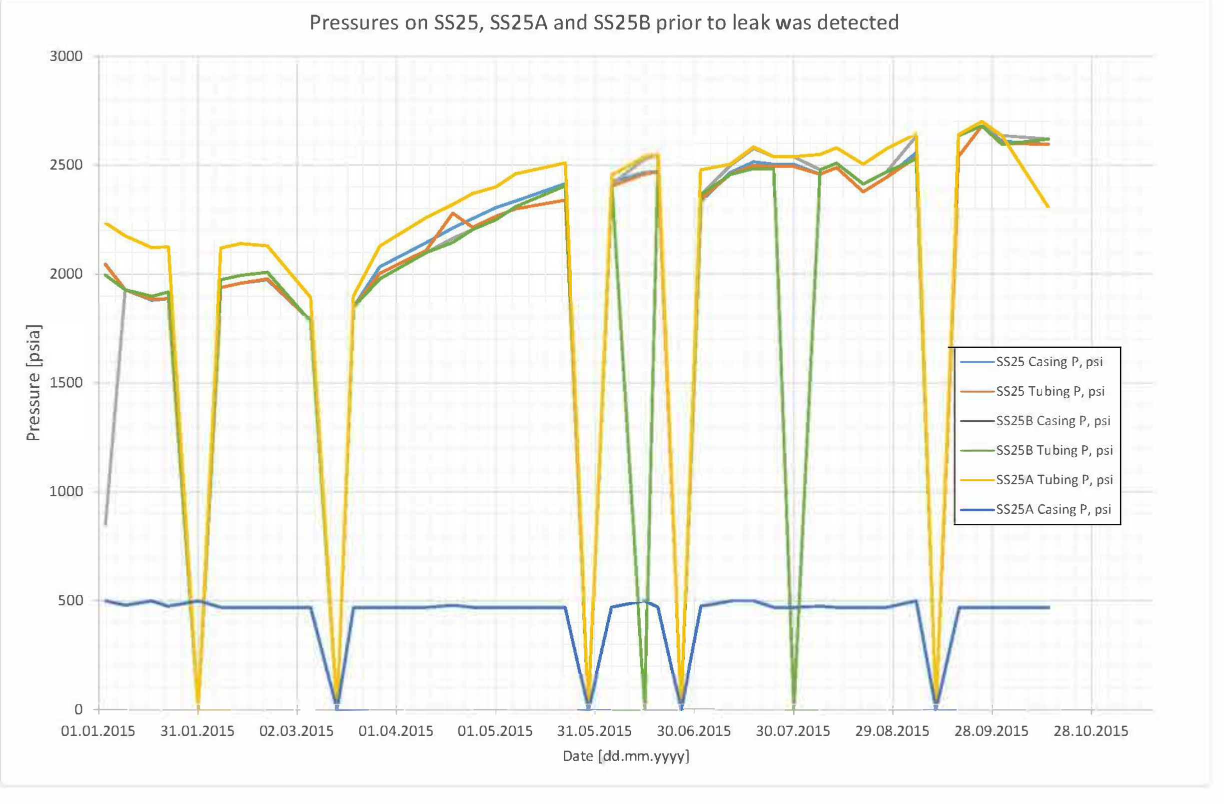

Figure 2.1: Recorded pressures on SS25, SS25A and SS25B prior to leak

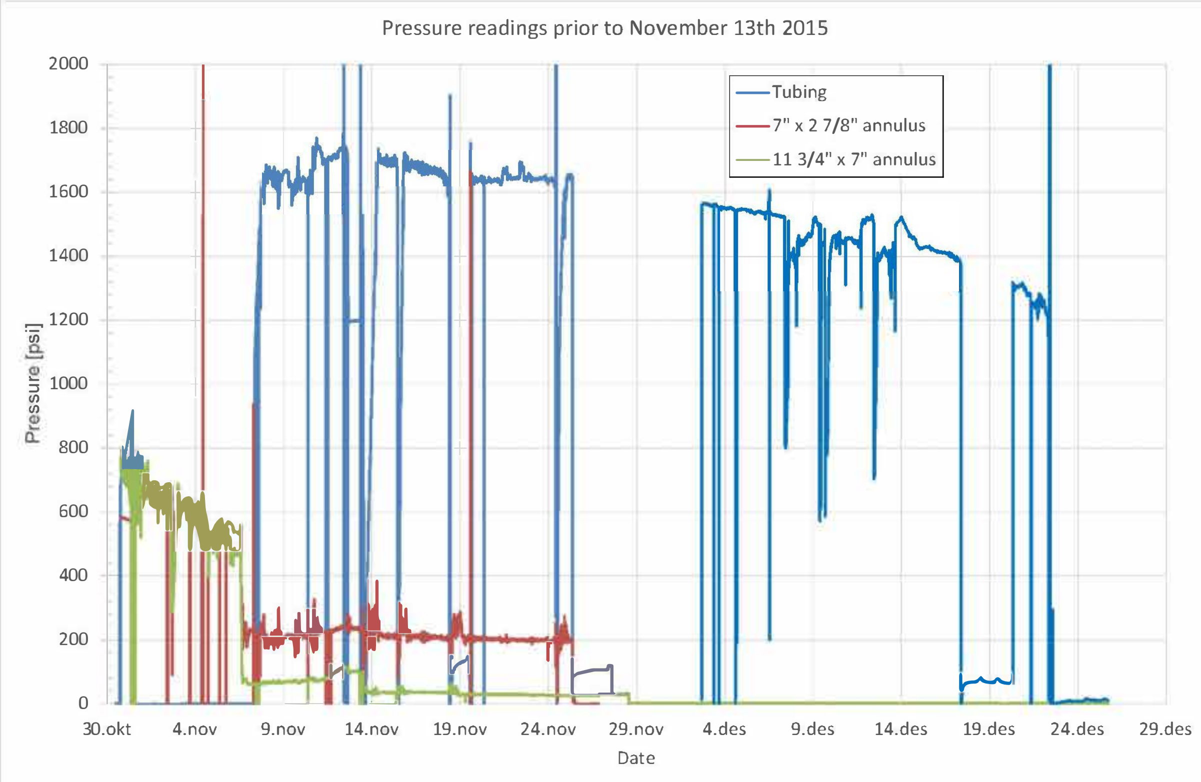

Figure 2.2: Recorded pressures on SS25 November to December 2015

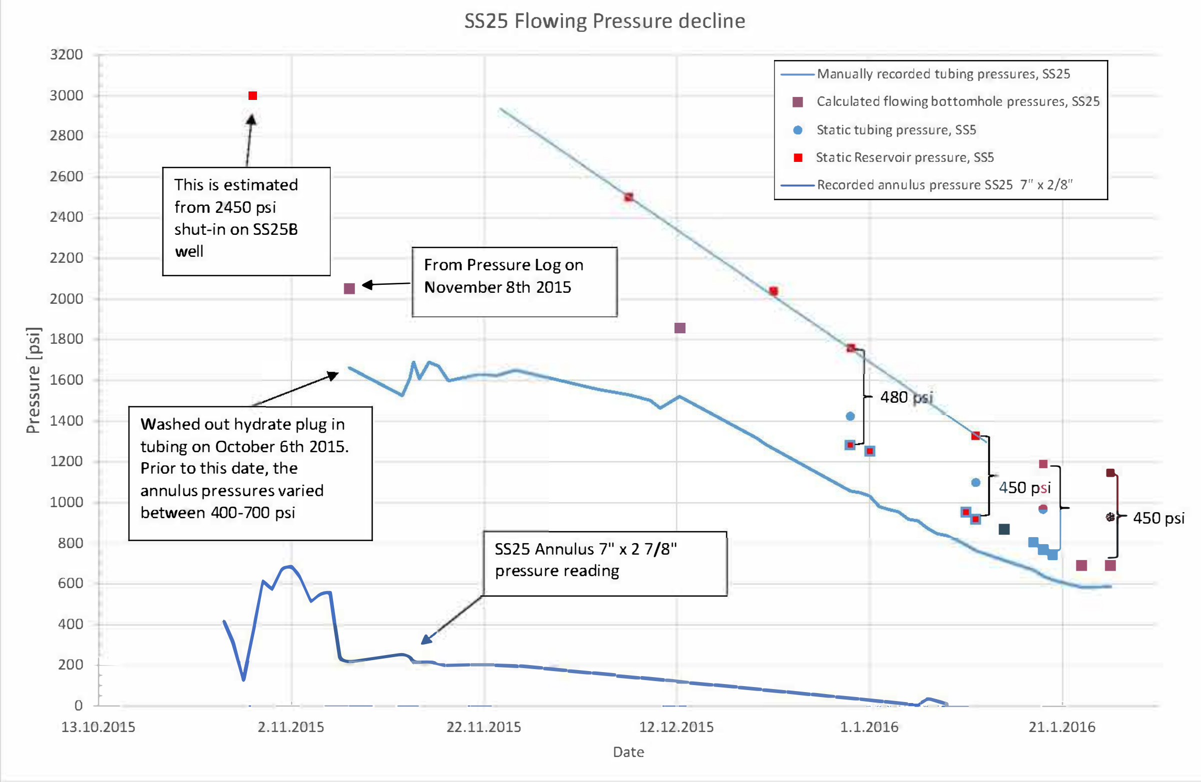

Figure 2.3: Pressure development on SS25 and SS5

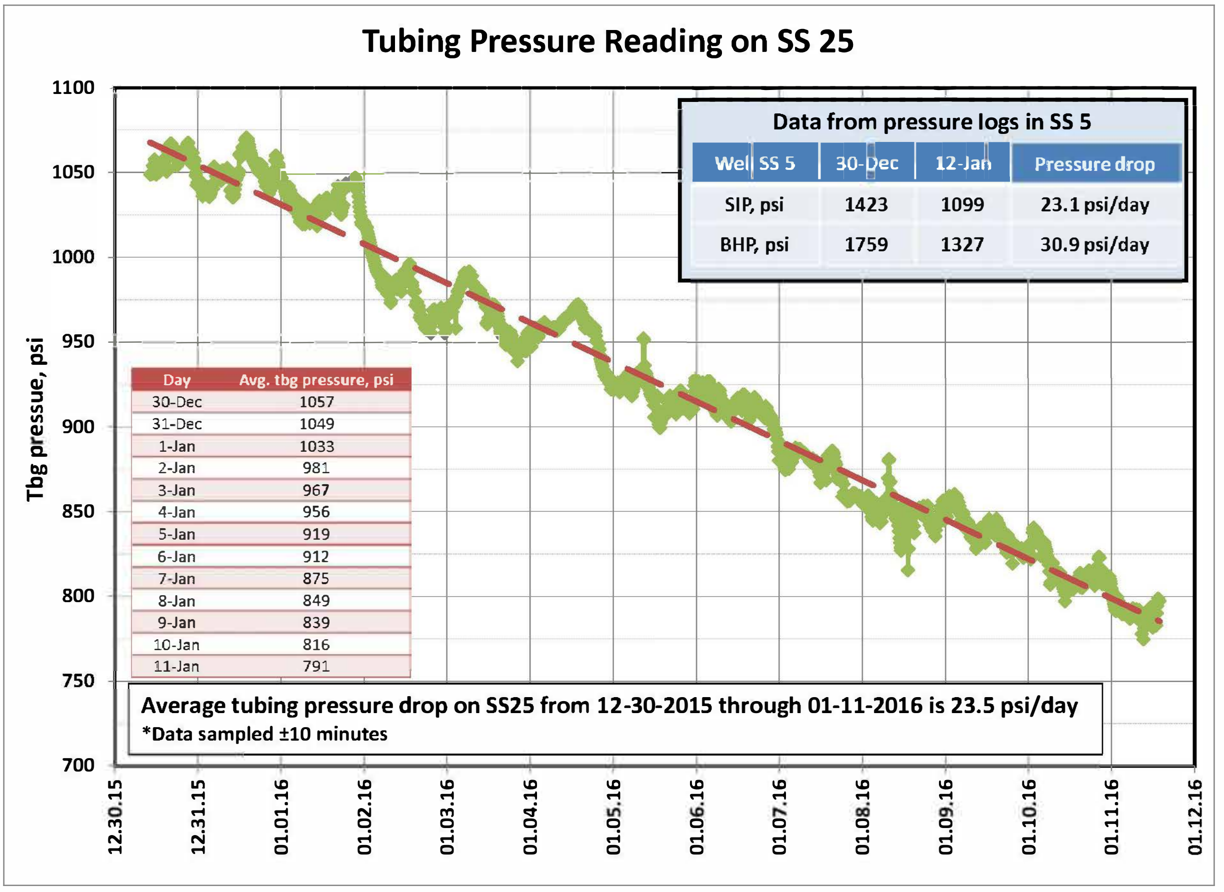

Figure 2.4: Tubing pressure reading on SS25

2.1 Pressure and temperature logs

Figure 2.5 shows a temperature log run in SS25 on October 21st 2014 after the well had been shut in for 2 days. There is an anomaly from ambient profile at approximately 8300 ft at where the temperature drops from 150 °F to 138 °F. Similar anomaly is observed from the SS5 well downhole (see Figure 2.8) and can caused by restrictions and expansion down hole during injection of gas.

On January 16th 2016, a pressure and temperature log was run in the SS25 well. As can be seen from Figure 2.7, there is an anomaly at around 3500 ft. This anomaly was later communicated to be related to some problems converting time to depth from the recorded values (which has been a problem for several of the wireline logs run in SS25). The bottomhole pressure was recorded to be 866 psi and the temperature was 144 °F.

The temperature log from November 9th 2015 is also plotted on the same Figure. This log shows a lower temperature compared to the measurement two months later. The higher bottomhole temperature could indicate an initial restriction downhole causing some cooling that later disappeared. Or simply that the injected gas in the reservoir has been heated up since injection. The pressure reading from the same log on November 9th 2015 show 2050 psi at the bottom. Both of these runs appear to have some operations and/or tool issues with respect to depth correlation.

A temperature log was also run on November 8th 2015. The log shows temperatures below freezing between 225 ft and 990 ft. This is probably the cause of the ice/hydrate plug forming during the initial polymer pill pumped on October 24.

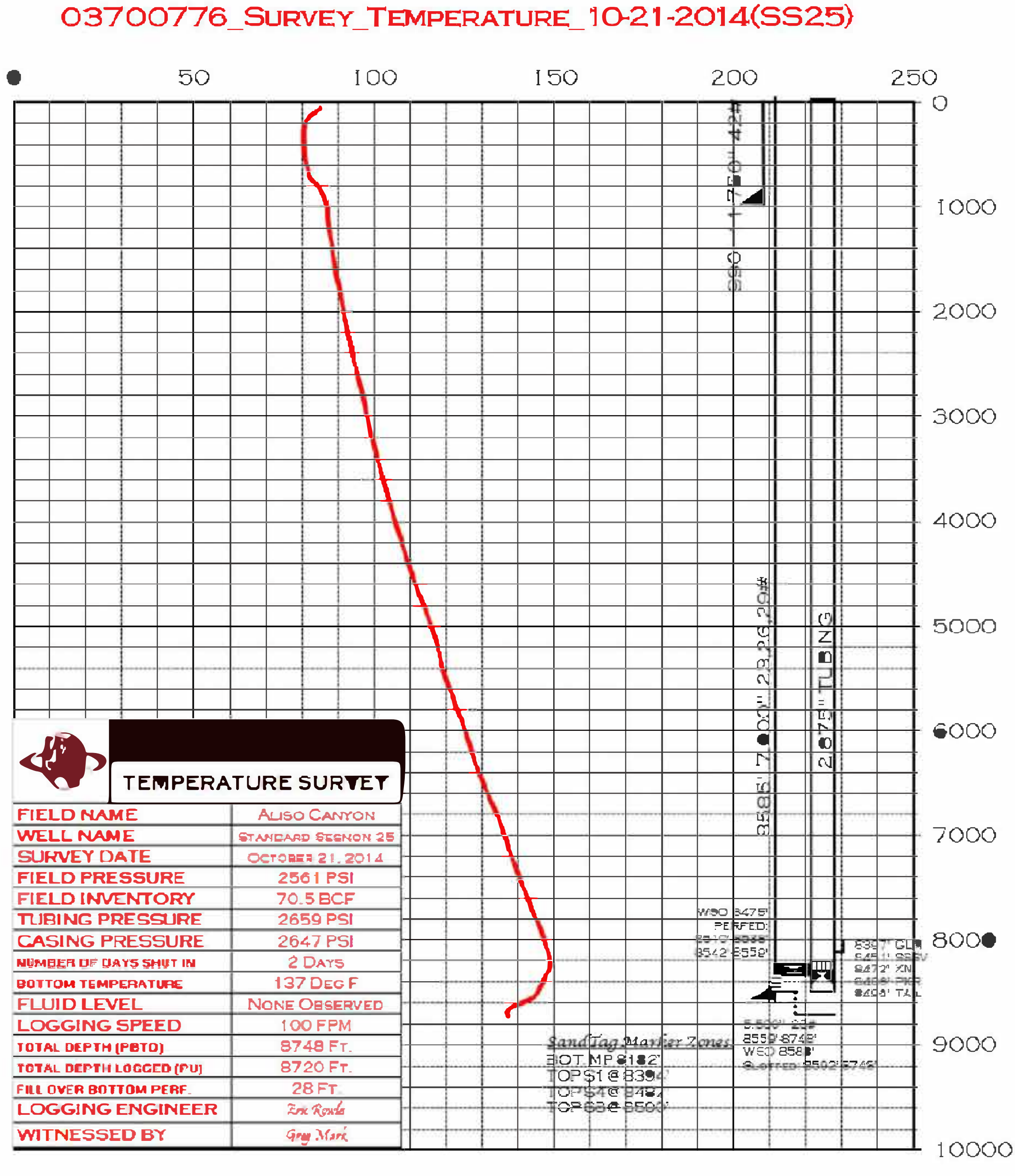

Figure 2.5: Temperature log from October 21th 2014

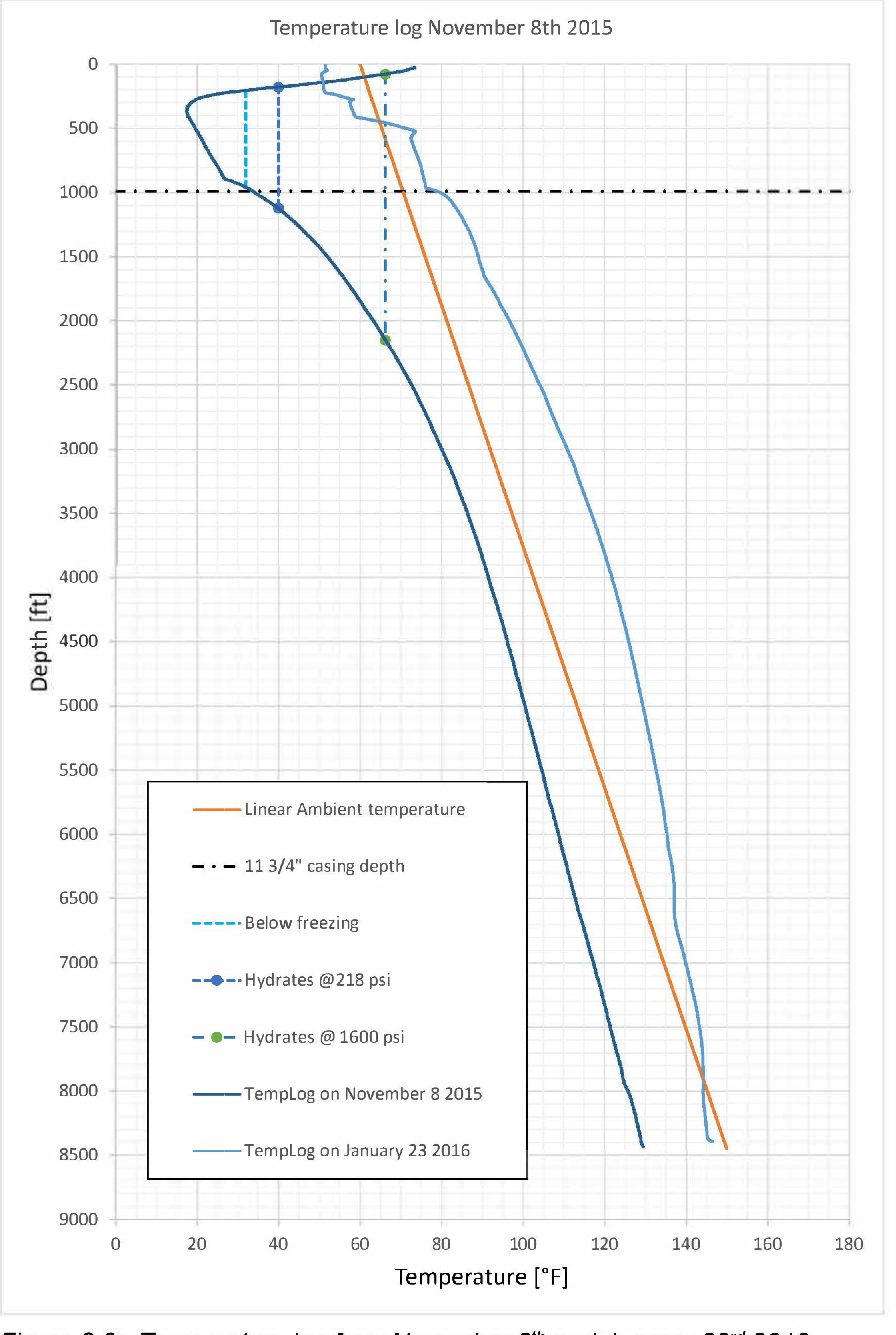

Figure 2.6: Temperature log from November 8th and January 23rd 2016

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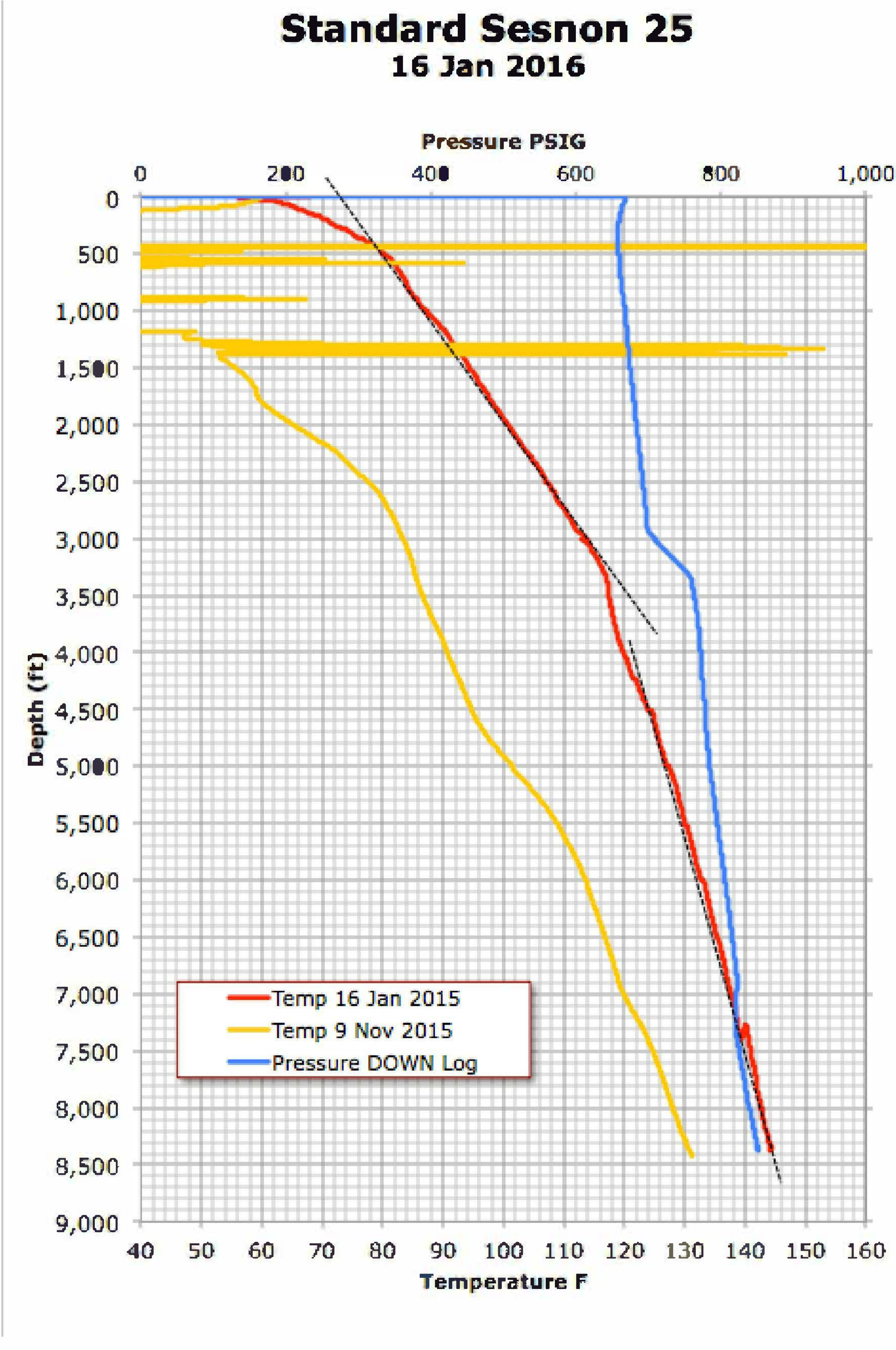

Figure 2.7: Pressure and temperature log from November 9 and January 16th 2016

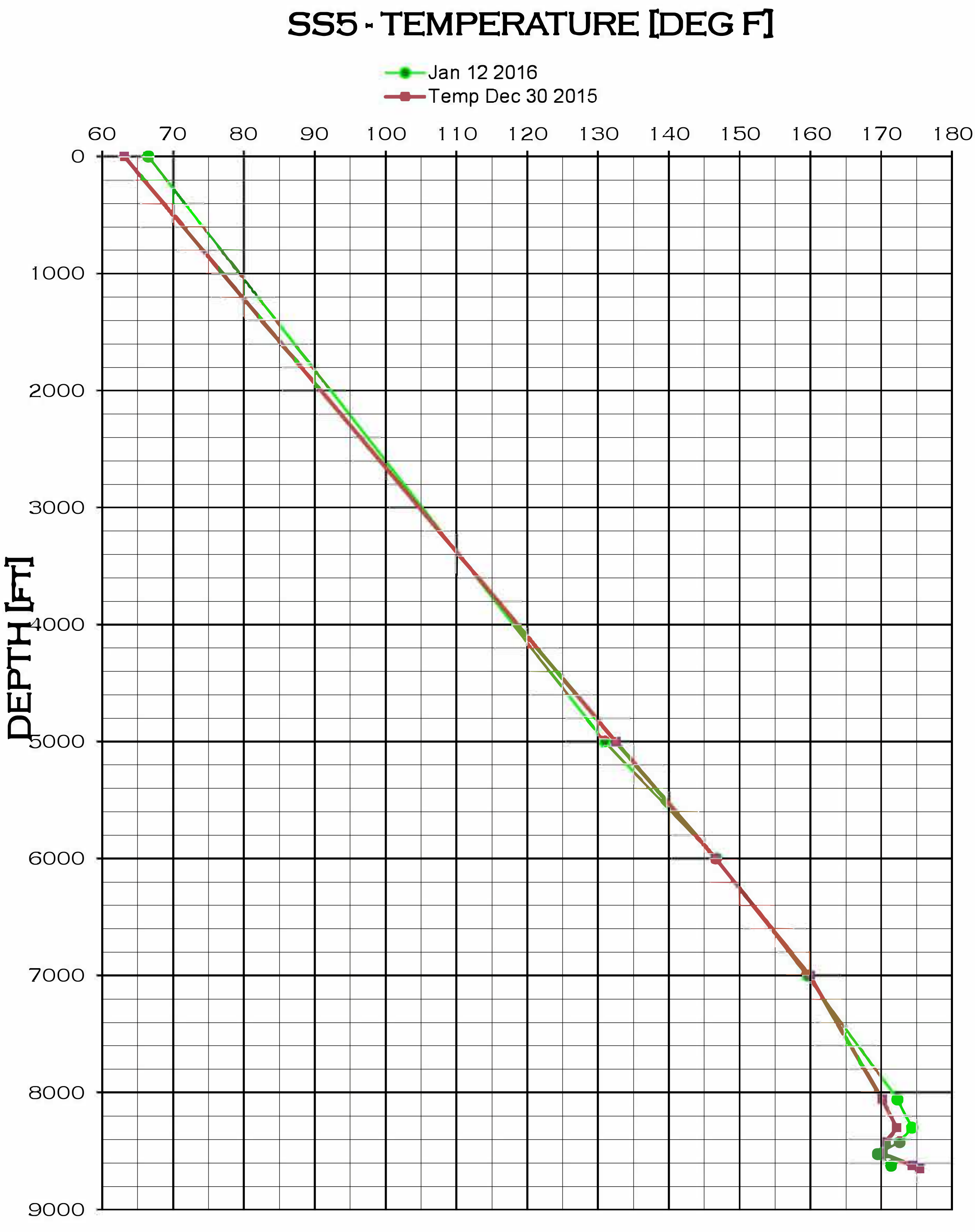

Figure 2.8: Temp. log from SS5 on December 30th 2015 and January 12th 2016

3. Evaluation of blowout potentials

3.1 General

The provided reservoir permeability range from 85 mD to 149 mD for the productive sands, see Table 1.4. The total thickness of the sands (S4, S6, S8, S10 and S12) is 171 ft. Using the provided net pay and permeability numbers, the total KH product is 13 150 mD·ft. Well tests do however indicate a lower productivity than achieved when summarizing the sands expected to contribute to the flow. The next sections show how the inflow performance relations (IPR) were matched with the provided data.

3.2 Provided well tests and estimation of IPR

Three different well tests have been provided for three different reservoir pressures, each with three different flow rates. These well tests were matched by using a Forchheimer inflow performance relation and a total kh product of 2 500 mD·ft, see Figure 3.1. This number is less than the 13 150 mD·ft as provided but is used on most of the simulations documented in this study.

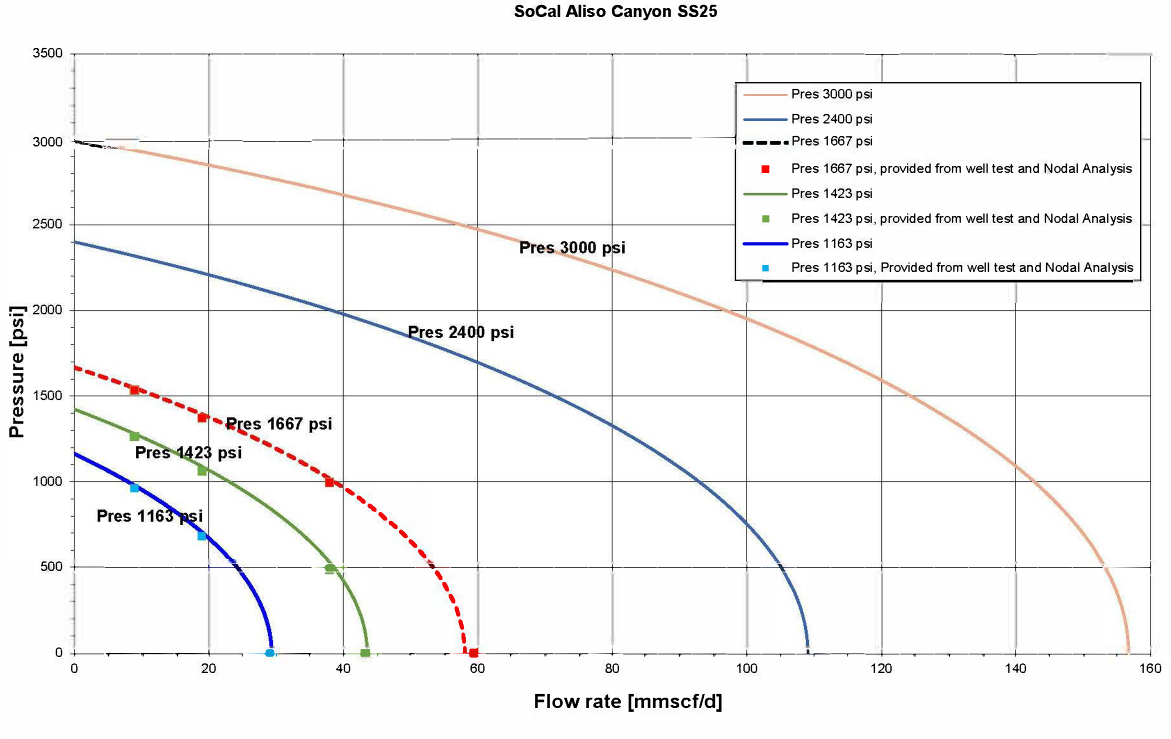

Figure 3.1: Estimated IPR matching provided well tests

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3.3 Potential flow paths

At surface the flow is reported to exit through the 11 ¾" surface casing x 7" annulus through a 2" nipple on the wellhead (a valve backed off after an early kill attempt) and through fissures outside of the 11 ¾" casing (either by flowing below the 11 ¾" shoe and fracturing to surface or through a shallower hole in the 11 ¾" casing. It appears from the original SS25 drilling records that losses occurred during cementing the 11 ¾" casing and required a surface cement job which may allow for an easy flow path back to surface. The formation around the 11 ¾" shoe is not believed to hold pressures above 800 psi and the readings show that the annulus pressure reached this pressure after the leak was detected, see Figure 3.2.

The actual flow path of the gas from the reservoir to surface is not known for certain. Based on the SS25 mechanical construction, it is believed that the flow path would be from the reservoir entering the lower completion through the perforated 5 ½" liner and through the perforations in the 7" casing below the production packer. Then through 2 ⅞" tubing through the production packer and exiting the tubing through the slots in the SSSV mandrel into the A annulus (between the 2 ⅞" tubing and the 7" casing). Then up to a shallow hole in the 7" casing flowing into the 11 ¾" annulus space (there is no cement in this annulus).

The gas then exits to the atmosphere initially around the 11 ¾" shoe at 990 ft (based on initial pressure readings on the 11 ¾" annulus) and later also through the 2" nipple on the wellhead and/or through a shallow hole in the 11 ¾" casing.

The hole in the 7" casing was confirmed when pumping a junk shot on November 13th 2015. After only 5 bbls were pumped, brine was observed from fissures and indicate a shallow hole in the 7" casing to the outer annulus between the 11 ¾" casing and 7" casing. Golf balls along with other plugging materials (rope, rubber, etc.) were pumped down the 7" x 2 ⅞" tubing that returned to the surface the next day (B&C representatives saw them pop out of the ground through fissures and were not damaged).

The flow path could also be from the reservoir and outside of the 7" all the way to surface. The 7" was cemented in a 10 ⅝" hole to a TOC depth of approximately 7000 ft. The cement bond log taken in 1973 shows good bond, however give the pressure and temperature cycling due to gas injection and production this bond may have deteriorated to the point to allow gas leakage. The WSO (water shut-off) perforations at 8475 ft in the 7" may also be a flowpath into the A annulus from the reservoir if the cement around the 7" is poor or washed out.

On February 7th 2016, the relief well (P39A) drilled to a depth of 8600 ft MD referenced P39A drill floor which should correlate to the depth of the WSO in SS25. No losses were taken and this indicates that the WSOs are not the source of the flow from the reservoir.

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Figure 3.2: Pressure on 11 ¾" x 7" annulus, October 30th 2015

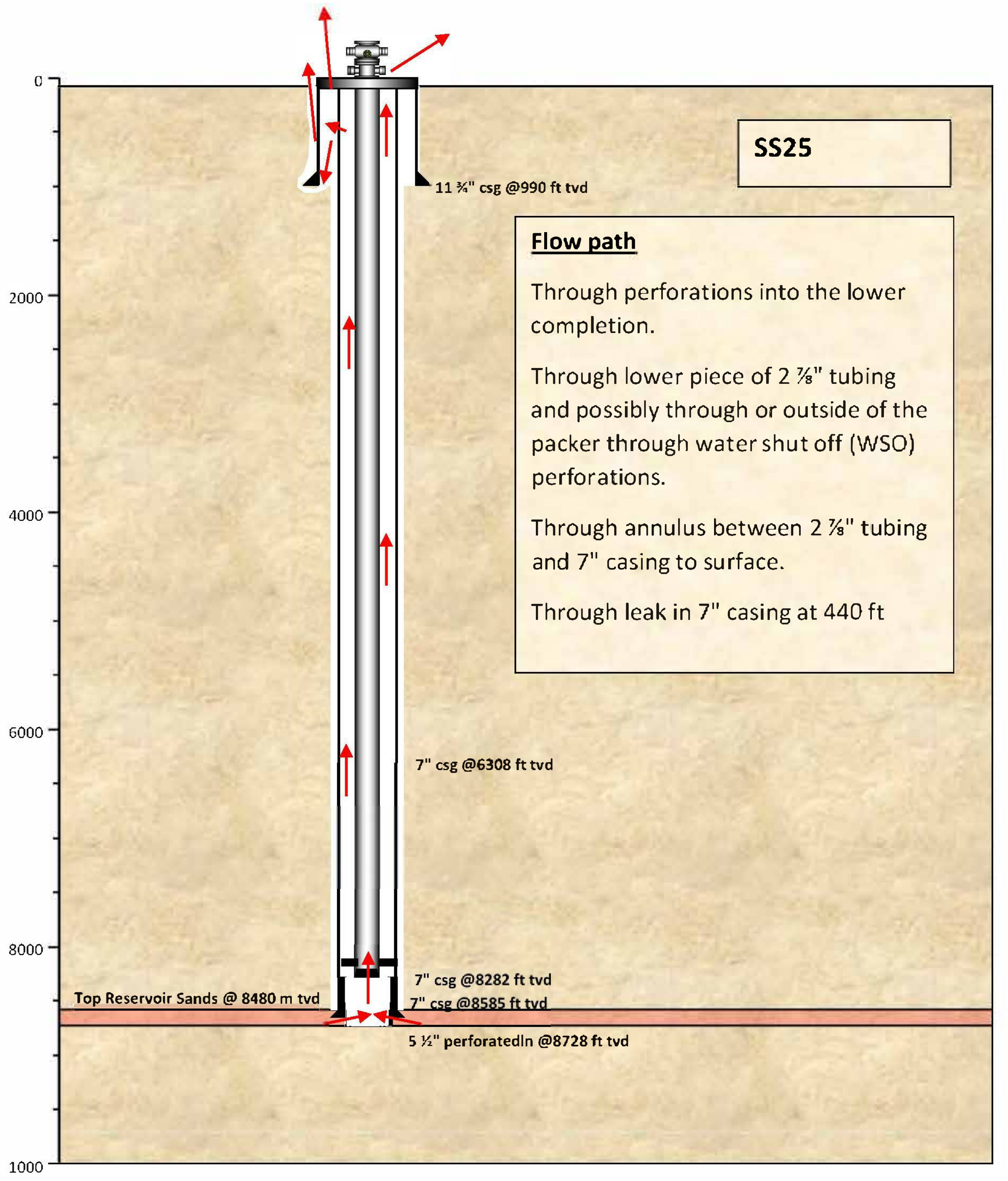

Figure 3.3: Schematic of potential flow path in annulus between 7" csg and 2 ⅞" tbg

3.4 Blowout potentials

The blowout potential assuming unrestricted flow of gas in the annulus space between the 2 ⅞" tubing and the 7" casing is estimated based on the kh product of 2 500 mD·ft. The flow rates are estimated assuming that gas only is flowing in the annulus (no mud), exiting through a leak in the 7" casing at 440 ft, and without any further restrictions to surface. The leak in the 7" tubing is estimated based on the temperature logs run in the hole indicating significant anomalies at the depth. The 7" x 2 ⅞" annulus is shut in at surface with a pressure gauge monitoring the pressure. The resulting tubing head and annulus pressures are listed in the table.

Table 3.1: Blowout potentials through 7" x 2 ⅞" annulus, kh of 2 500 mD·ft

Reservoir pressure [psia]	FBHP [psia]	Gas rate [mmscf/d]	7" csg [psia]	THP [psia]
3000	1950	82	176	1600
2400	1520	64	140	1250
1667	960	40	90	790
1323	780	32	70	645
1163	590	24	55	490
1000	470	19	45	393

Table 3.2: Blowout potentials through 7" x 2 ⅞" annulus, kh of 13 150 mD·ft

Reservoir pressure [psia]	FBHP [psia]	Gas rate [mmscf/d]	7" csg [psia]	THP [psia]
2800	2540	110	227	2075
2400	2170	92	195	1775
2000	1800	75	162	1470
1800	1610	68	145	1320
1600	1420	59	130	1170
1400	1230	51	112	1015
1200	1040	43	95	860
1000	850	35	78	705

3.5 Compressibility of gas

To give an overview of the gas volumes at reservoir conditions compared to the rates released at surface, simulations were performed for various conditions. The exit condition has been referenced as standard conditions, that is 14.6 psi and 60 °F. As an example, one barrel of gas taken at 3000 psi and 150 °F expands to 200 barrels at surface.

One barrel of gas taken at 1000 psi and 150 °F expands to 63 bbls at surface. One barrel of gas taken at 1300 psi and 70 °F expands to 107 bbls at surface.

All gas rates in this report are referenced as the gas rate at standard condition, mmscf/d. To convert the rates to down hole conditions, the compressibility should be taken into account. As an example, 20 mmscf/d at surface yields only 0.2 mmft³/d downhole at 1500 psi and 150 °F.

Figure 3.4: Expansion of the gas from reservoir conditions to surface

One reservoir barrel		Barrels at surface	
Pressure	**Temperature**	**14.6 psi**	**60 °F**
3000 psi	150 °F	200	
2500 psi	150 °F	165	
2000 psi	150 °F	130	
1500 psi	150 °F	100	
1000 psi	150 °F	63	
1500 psi	70 °F	126	
1400 psi	70 °F	117	
1300 psi	70 °F	107	

3.6 Joule-Thomson cooling of gas and hydrate equilibrium curve

Simulations were performed to evaluate the temperature drop caused by a potential restriction in the flow path. The sudden expansion of fluids occurring over a restriction will result in cooling of the gas, see Table 3.3.

The hydrate equilibrium curve for the storage gas is shown in Figure 3.6. Given access to gas and free water, stable hydrates can exist to the left of this curve, that is at lower temperatures and higher pressures than the equilibrium curve.

Table 3.3. Joule-Thomson cooling of gas for various pressure drops.

Upstream pressure [psi]	Upstream temperature [°F]	Downstream pressure [psia]	Downstream temperature [°F]
200	50	20	35
400			18
600			2
800			-14
1000			-29
1200			-45
1400			-61
1600			-74
2000			-90
2400	150	2050	141
2800	150	2050	132

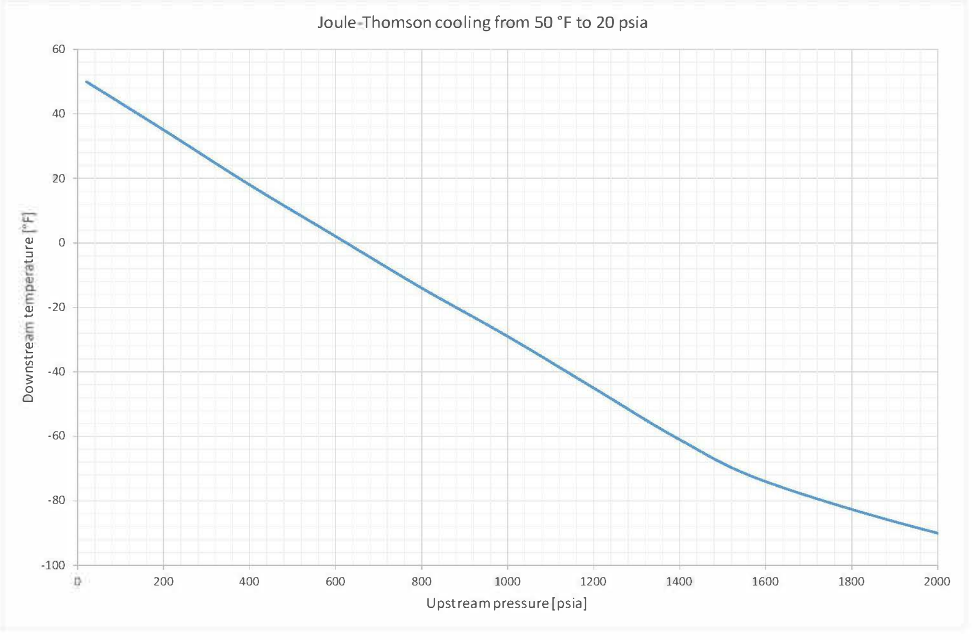

Figure 3.5: Joule-Thomson cooling from high pressure and 50 °F to 20 psia

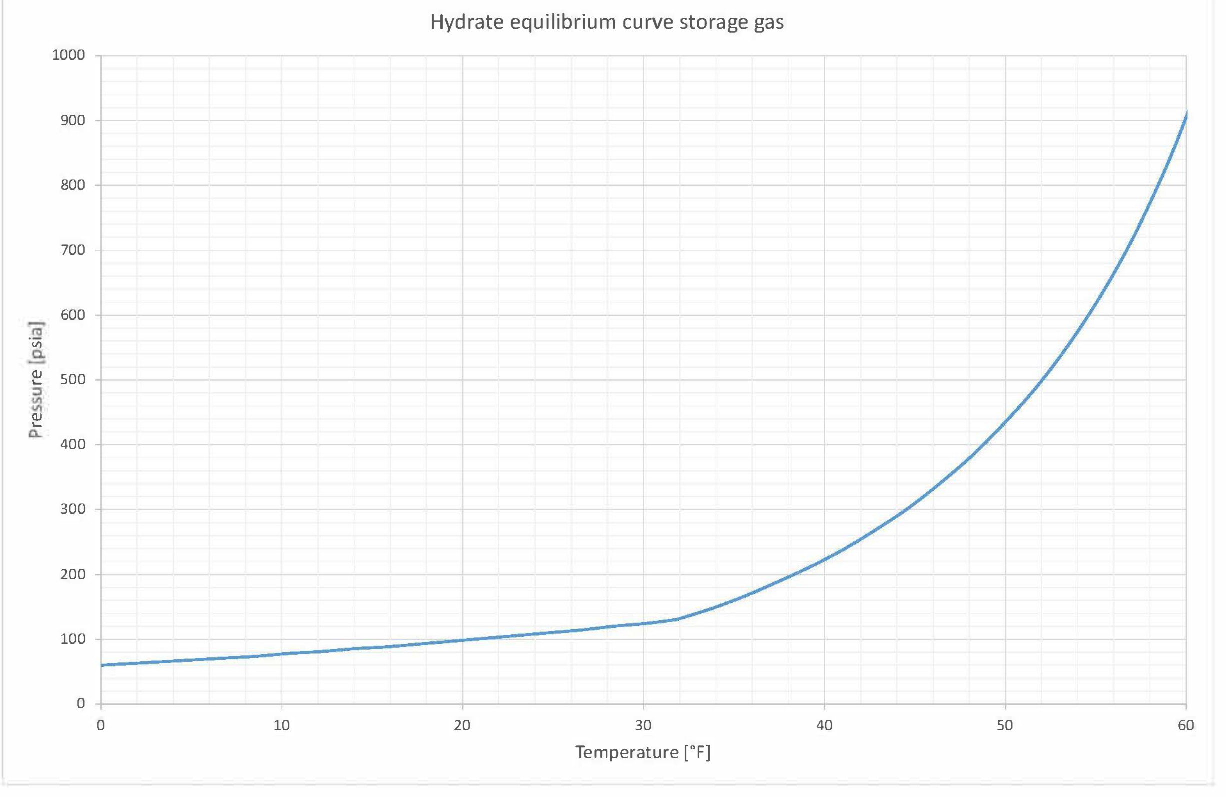

Figure 3.6: Hydrate equilibrium curve for storage gas

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3.7 Potential flame height if gas flow on fire

In the event that the flow exiting the SS25 well should catch on fire, the flame height is estimated for reference. The estimation is based on the Heskestad correlation for estimation of a burning plume height:

$$L_f = 0.235 \cdot Q_h^{0.4} - 1.02D$$

where

- L_f is the height of the flame [m]
- Q_h is the heat release rate [W]
- D is the reference diameter of the flame [m]

The heat release rate is estimated from the gas flow rate using the calorific value of the fluid according to the formula:

$$Q_h = Ca \cdot Q$$

where

- Ca is the calorific value of the gas [J/m³]
- Q is the gas flow rate [m³/s]

This correlation has been used on several gas blowouts, including the Hassi R'Mel blowout in Algeria in 2001. On this blowout the correlation showed good match with the measurements for the rate estimated to be 5.5 MSm³/d (200 mmscf/d).

For the gas flowing from well SS25, the calorific value is estimated to be 40 MJ/m³. Based on the above Heskestad correlation the flame height versus flow rate is shown in Figure 3.7. An average diameter of the flame base of 16 ft (5 m) is used as the reference diameter D in the calculations. (The flame height is not too dependent on the average diameter).

The estimated flame height would be 80 ft for a rate of 20 mmscf/d and 140 ft for a rate of 60 mmscf/d, see Figure 3.7.

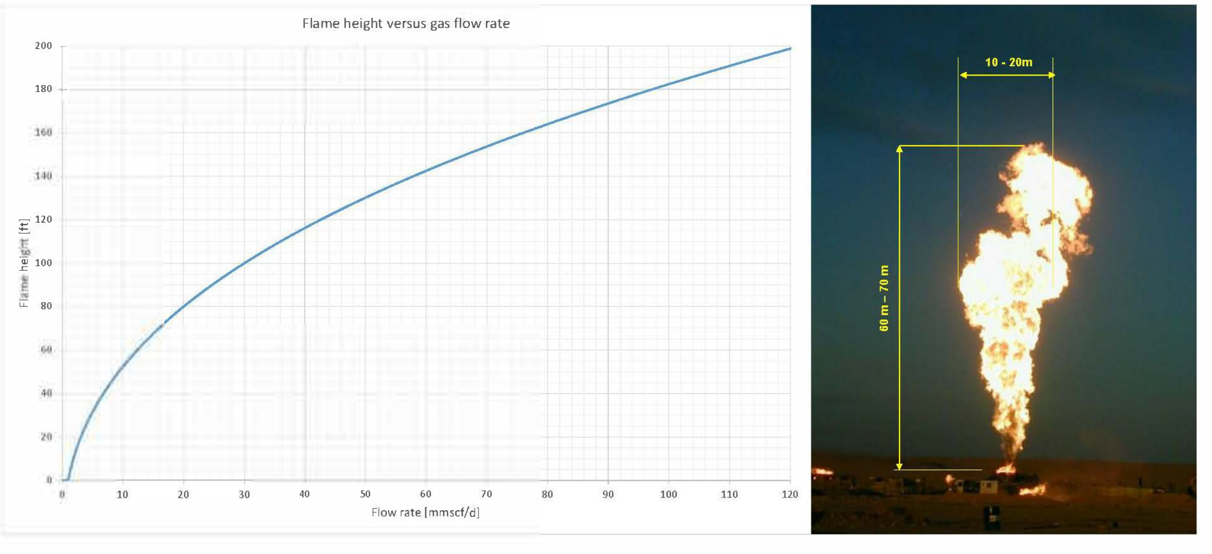

Figure 3.7: Flame height versus flow rate, and gas blowout in Algeria in 2000

3.8 Flow restriction in the lower part of the 2 ⅞" tubing

Assuming that the production packer sitting at 8486 ft in SS25 is undamaged and sealing the annulus, the flow from the reservoir is through the tubing from 8496 ft to the seven 3" x ½" slots in the tubing above the packer at 8451 ft. This is a length of only 45 ft and the equivalent flow area through the slots is 10.5 in² which again yields an equivalent diameter of 3.656 in. Hence, the frictional pressure drop occurring over this short section of 2 ⅞" tubing is limited, see Table 3.4.

Table 3.4: Frictional pressure drop through lower part of 2 ⅞" tubing

Flow rate [mmscf/d]	Shut-in Tubing head pressure [psi]	Flowing tubing pressure at 8451 ft [psi]	Flowing tubing pressure at 8496 ft [psi]	Total Pressure drop [psi]
92	1700	2080	2341	261
82	1700	2080	2290	210
62	1700	2080	2203	123
20	1700	2080	2095	15
30	583	700	788	88
24	583	700	757	57
20	583	700	740	40

4. Flow to tests to separator and withdraw line

4.1 General

Prior to the kill attempts starting on November 13th 2015, an attempt was made to bleed down the 7" x 2 ⅞" annulus through the test separator. Simulations of the operations have shown that there were more restrictions in the flow path between the reservoir and the surface than what the frictional pressure drop in the annulus between the 7" casing and the 2 ⅞" tubing would cause. Neither would the expected flow configuration down hole create enough pressure drop to explain the low surface pressure readings.

The slots in the tubing where the subsea safety valve used to sit down hole are reported to be 3" long and 0.5" inches wide, and there are seven of them. This yields an equivalent diameter of 3.656 in which is larger than tubing diameter, and hence, this is not contributing to the pressure reduction required to match the observed readings.

The pressures outside of the 7" casing, in the annular space between the 11 ¾" casing and the 7" casing, was also monitored during the flow tests. This pressure was almost similar to the 7" x 2 ⅞" pressure, and this is an indication of communication between the two annuli surrounding the 2 ⅞" tubing.

4.2 Production to test separator on October 26th 2015

On October 26th 2015, the well was produced through the 11" x 7" annulus to the test separator. Initially, the choke was set at 16/62" opening, later it was opened to 23/64" and the flow was reported to be 8 mmscf/d.

The pressure upstream of the choke was reported to be 413 psi and 404 psi during the two flow test.

Simulations were performed to reproduce these flow tests, but it was not successful to achieve the high rate reported combined with the low upstream pressure.

The reported upstream pressure of 404 psi is not enough pressure to produce 8 mmscf/d through a 23/64" choke. This high rate requires an upstream pressure of above 2000 psi to allow for the rate to flow through the relatively small choke opening. It is therefore concluded that some of the reported numbers from this flow test is incorrect.

Table 4.1 shows the flow reported rates and pressure together with the simulated values. As the table indicates, if the upstream pressure is correct, the gas rate through the 23/64" choke can only be 1.2 mmscf/d and not 8 mmscf/d.

Table 4.1: Flow out of 11" x 7" annulus to test separator on October 26th 2015

Choke opening	Reported gas rate [mmscf/d]	Reported 11"x7" pressure [psi]	Rate from simulations [mmscf/d]	Upstream pressure from simulations [psi]
16/64"	na	413	4.1	2450
23/64"	8	404	8.3	2400
16/24"	na	413	0.6	413
23/64"	8	404	1.2	404

4.3 Bleed down test on October 27th 2015

On October 27th 2015, the 7" x 2 ⅞" annulus was tried bled down to the test separator. The choke was set at 11/62" opening and the flow was reported to be 3 mmscf/d. The pressure upstream of the choke was reported to be 419 psi during the test.

Similar to the production test on October 26th, the reported numbers cannot be correct. It is not possible to produce a rate of 3 mmscf/d through a 11/64" choke with only 419 psi upstream of the choke. Either the pressure is wrong, or the rate is wrong.

Table 4.2: Flow out of 7 x 2 ⅞" annulus to test separator on October 27th 2015

Choke opening	Reported gas rate [mmscf/d]	Reported 7"x2⅞" pressure [psi]	Rate from simulations [mmscf/d]	Upstream pressure from simulations [psi]
11/64"	3	419	2.0	2450
23/64"	na	416	8.6	2380
11/64"	3	419	0.3	419
23/64"	na	416	1.3	416

4.4 Summary of flow test to test separator in October

The results from the flow test being performed on October 26th and October 27th 2015 show that there is communication between the two annuli surrounding the 2 ⅞" tubing on these dates. The surface pressure readings on the annuli show similar pressures, both when bleeding down the 11 ¾" x 7" annulus and when bleeding down the 7" x 2 ⅞" annulus. This indicates that the flow path between the two annuli has a significant flow capacity not creating any frictional pressure drop, even at rates up to 8 mmscf/d (the reported bleed down rates). Furthermore, the results and simulations show that there is a restriction in the flow path from the reservoir to the surface causing the low surface pressure readings.

Simulations show that unrestricted flow from the reservoir through the annulus between the 7" and the 2 ⅞" would result in rates at the level as measured. However, the reported upstream pressures are too low to allow the high rates through the small choke openings.

It is therefore concluded that there are some errors in the reported numbers from the flow tests as the combination of low choke upstream pressure and high reported rates do not match. A rule of thumb for calculating the maximum flow through a choke for dry gas cases is:

$Q = 24 * (P_{UP} + 15) * D_{choke}^2 / 1000$

where,
Q, flowrate in mmscf/d
P_{UP}, choke upstream pressure in psia
D_{Choke}, choke diameter in inches

Hence, a choke diameter of 23/64" would yield a flow rate of :

$Q = 24 * 416 * 0.359375^2 / 1000 =$ 1.3 mmscf/d

This rate, also confirmed by simulations, is much less than the reported of 8 mmscf/d and hence some of the parameters provided are believed to be wrong:

- The upstream choke pressure should be higher
- Or, the gas rate should be lower
- Or, the choke size should be higher
- Or a combination of the three

If the rate of 8 mmscf/d is correct over the 23/64" choke, the upstream pressure should have been above 2000 psi.

4.5 Flow from tubing on December 7th 2015

On December 7th 2015, an attempt was made to flow the tubing through a ½" choke to the withdrawal lines, at the time assumed pressure is 485 psi. The tubing pressure was 1526 psi prior to the test. Simulations show that this equals a flowing bottomhole pressure of 1739 psi. The reservoir pressure at this date is estimated to be 2500 psi, see Figure 2.3.

At 09:30, the flow was initiated and the initial flow rate was reported to be 11 mmscf/d. This rate flow rate across the choke was reproduced by the simulations. The tubing head pressure decreased to 805 psi and the reported rate was between 5 and 7 mmscf/d. In contrast to the bleed down operations being done on the annuli in October, the relationship between flow rate and upstream pressure matched with the simulations. Simulations showed a rate of 5 mmscf/d out of the tubing based on the provided data.

The next morning, December 8th, the reported flow rate was estimated to be 2 mmscf/d and the choke pressure was 1448 psi. At 09:00 on December 8th 2015, the choke was opened to ⅞" and the flowing tubing head pressure decreased to 1438 psi. Estimated gas rate was now 5.5 mmsc/d. The choke was then opened fully to 1 ½" opening and there was no difference in tubing pressure nor flow rate.

For these last recordings, it is believed that the back pressure increased from the initial 485 psi as assumed during the initial flow test. The pressure of 485 psi was determined from the daily operation report.

Table 4.3 shows the resulting gas flow over a choke with given upstream pressure condition. The downstream pressure has been fixed at 485 psi.

Table 4.3: Gas flow through choke for different pressure conditions

Choke opening	Reported gas rate [mmscf/d]	Reported 2 ⅞" pressure [psi]	Rate from simulations [mmscf/d]	Modelled upstream pressure for simulations [psi]
½" (485 psi back p)	11	1525	11	1525
½" (485 psi back p)	5-7	805	5	805
½" (485 psi back p)	2	1448	10	1448
⅞" (485 psi back p)	5.5	1438	30	1438
1 ½" (485 psi back p)	5.5	1443	70	1443

5. Washing out ice/hydrate plug in tubing on October 6th

5.1 General

The washing operation of the plugged tubing occurring on October 6th 2015 influenced on the conditions in the wellbore. After this job was commenced, the pressures on the annuli dropped and never recovered back to the higher initial readings, see Figure 2.2. As the conditions in the tubing on October 24th, when a polymer pill was attempted pumped, was inside of the hydrate equilibrium curve, it is believed that hydrates were formed and plugged the tubing.

5.2 Washing operation

The washing operation pumping 10.8 ppg $CaCl_2$ trough coiled tubing started at 11:20 hrs on October 6th 2015. The ice/hydrate was tagged at 20 ft. With the washing assembly at 482 ft, the choke pressure decreased (reported first to 1200 psi) and it was not possible to maintain backpressure. Returns were lost. The coil was pulled into the riser and it was continued to pump down the tubing with no pump pressure.

After 62 bbls were pumped, the gas activity from fissures increased. In total more than 200 bbls were pumped down hole without observing any returns at surface.

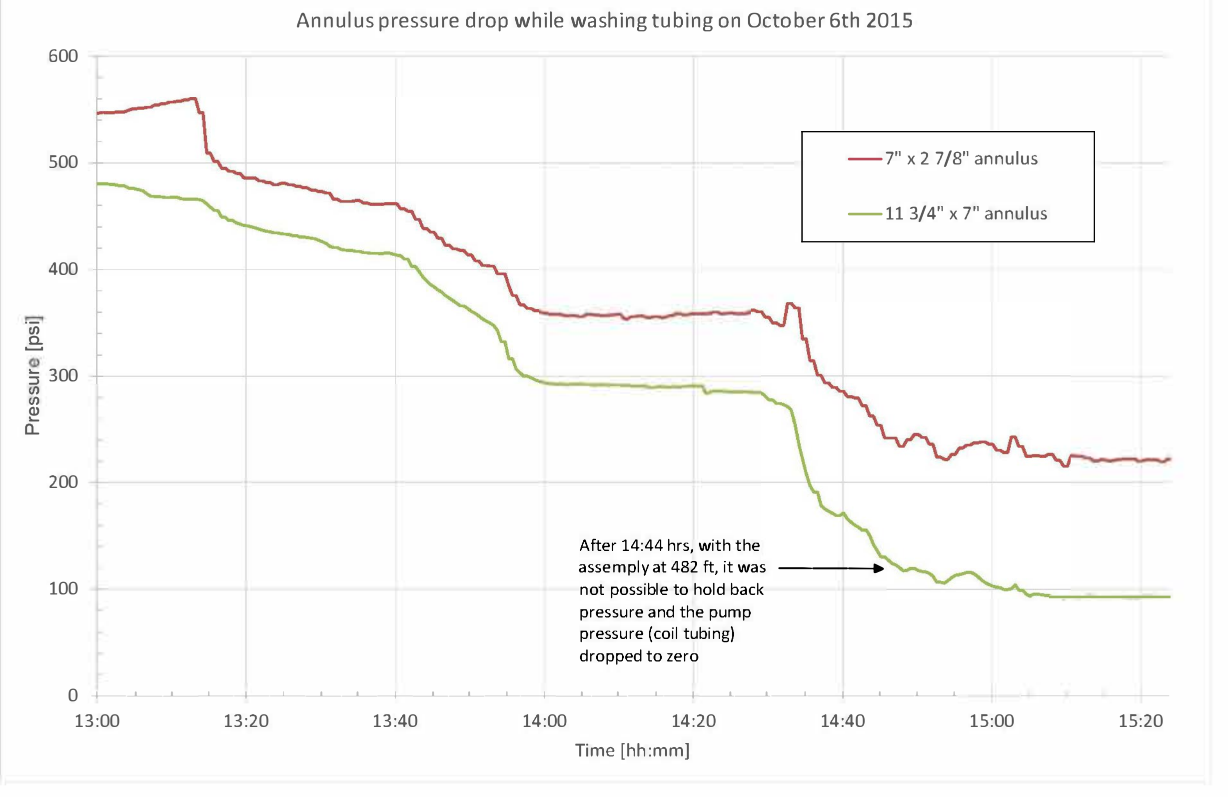

Figure 5.1: Pressure decline in annuli during washing operation on October 6th 2015

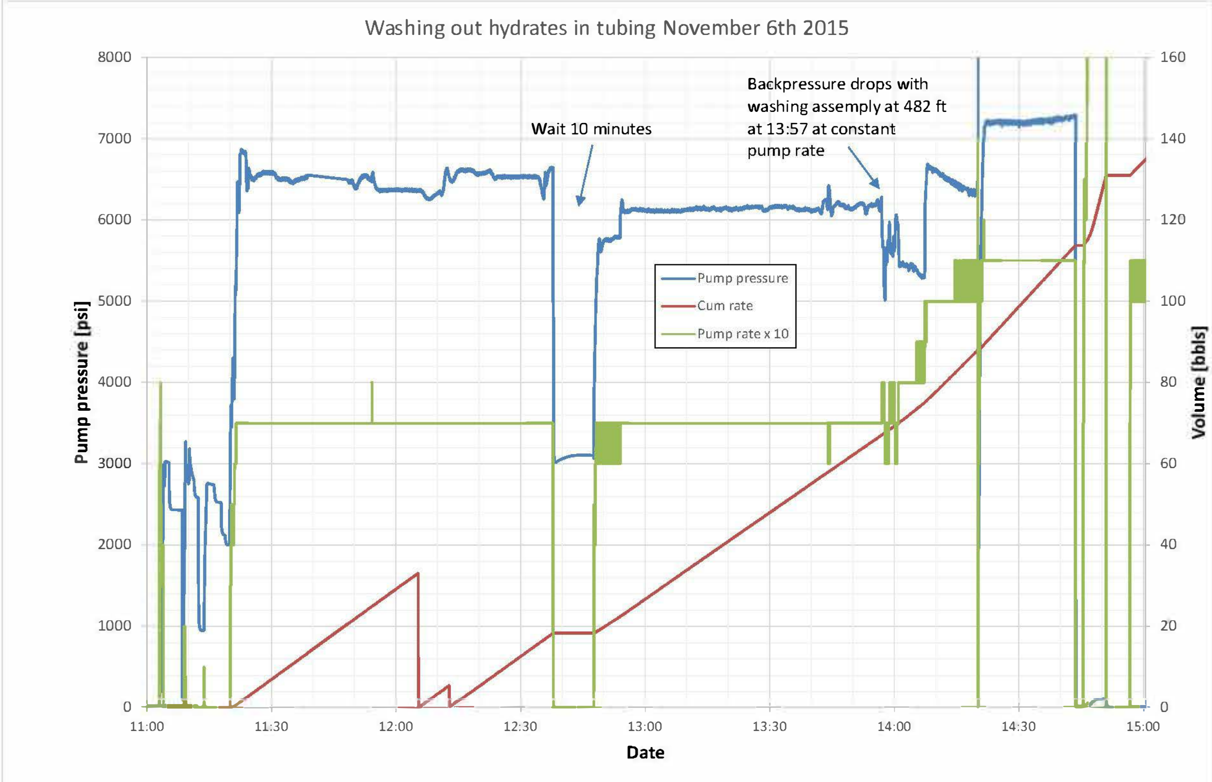

Figure 5.2: Rate and pump pressure during washing operation on October 6th 2015

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6. Evaluation of kill attempts from November 13th 2015

6.1 General

Evaluations of several of the kill attempts pumping down the tubing were performed to diagnose the flow situation in the SS25 well. Simulations of the kill attempts were performed to validate the dynamic model and ensure it was capable of reproducing the transient situation in the wellbore. The results from the simulations will give valuable information in the process of planning for and running the planned relief well kill operation.

6.2 Conditions in SS25 prior to kill attempt on November 13th 2015

Provided pressure readings from November 1st show is shown in Figure 6.1. Initially, the pressures on the 11 ¾" x 7" annulus and the 7" x 2 ⅞" annulus were similar. On November 6th, a potential hydrate plug sitting inside the 2 ⅞" tubing between 20 ft and 188 ft was washed out. With the washing assembly at 482 ft, the pressure decreased and returns were lost. After hydrate plug was washed out of the tubing, approximately 200 bbl of fluid were pumped and lost down hole. After this date, both annuli pressures dropped. From this date forward, the 7" x 2 ⅞" pressure was about 200 psi, the 11 ¾" x 7" pressure about 100 psi. The tubing pressure varied between 1550 and 1700 psi, see Figure 6.1. A reservoir pressure of 3000 psi was used for these simulations.

Figure 6.1: Provided pressure readings prior to November 13th 2015

AC_BLD_0076314

6.3 Pressure drop pumping down the 2 ⅞" tubing

The expected pressure drop from surface of the tubing to the bottom of the tubing is calculated for different mud weights, see Table 6.1. For example, if the exit pressure at the end of the tubing down hole is 2000 psi, the pressure at surface of the tubing should be zero pumping 6 bpm of 8.6 ppg mud.

Table 6.1: Pressure drop (hydrostatic and friction) pumping down the 2 ⅞" tubing

Pump rate [bpm]	8.6 ppg	9.6 ppg
0	-3740	-4170
1	-3680	-4080
2	-3530	-3870
3	-3280	-3540
4	-2930	-3090
5	-2490	-2540
6	-1960	-1880
7	-1330	-1120
8	-610	-250
9	210	730
10	1120	1820
11	2130	3010
12	3230	4310

6.4 Pumping operation, November 13th 2015

Prior to the pumping operation on November 13th 2015, the recorded shut-in pressure was 1600 psi on the tubing. The pumps were ramped up to 8 bpm using 9.6 ppg mud filling up the tubing, then later a constant rate of 7.2 bpm was maintained.

The initial reduction in pressure is expected when heavy mud replace gas in the tubing, hence increasing the hydrostatic head.

The maximum pump pressure never exceeded 700 psi during the period of constant pump rate, and this indicate that fluid exits at the bottom at a pressure of 1700 psi based on the estimated pressure drop down the tubing. Furthermore, the pump pressure is falling and is only 300 psi at the end of the period between 12:10 and 12:50 hrs with constant pump rate of 7.2 bpm and with constant density of 9.6 ppg. This equals an exit pressure of only 1300 psi down hole.

Figure 6.3 shows the expected pump pressures assumed the kill fluid was exiting the tubing and transported with the gas up the annulus between the 2 ⅞" tubing and the 7" casing. As can be seen there is a discrepancy between the simulated pressure and the observed pressure. The sudden reduction in pump pressure can explain opening a fracture or new flow path to a low pressure zone.

In order to match the observed pressure readings, a fracture zone taking fluid at a pressure of 1700 psi was included at the bottom. This relatively low pressure of 1700 psi equals a gradient of only 3.9 ppg EMW at the tubing perforations at 8381 ft. The simulations show a better match with the observations, see Figure 6.5.

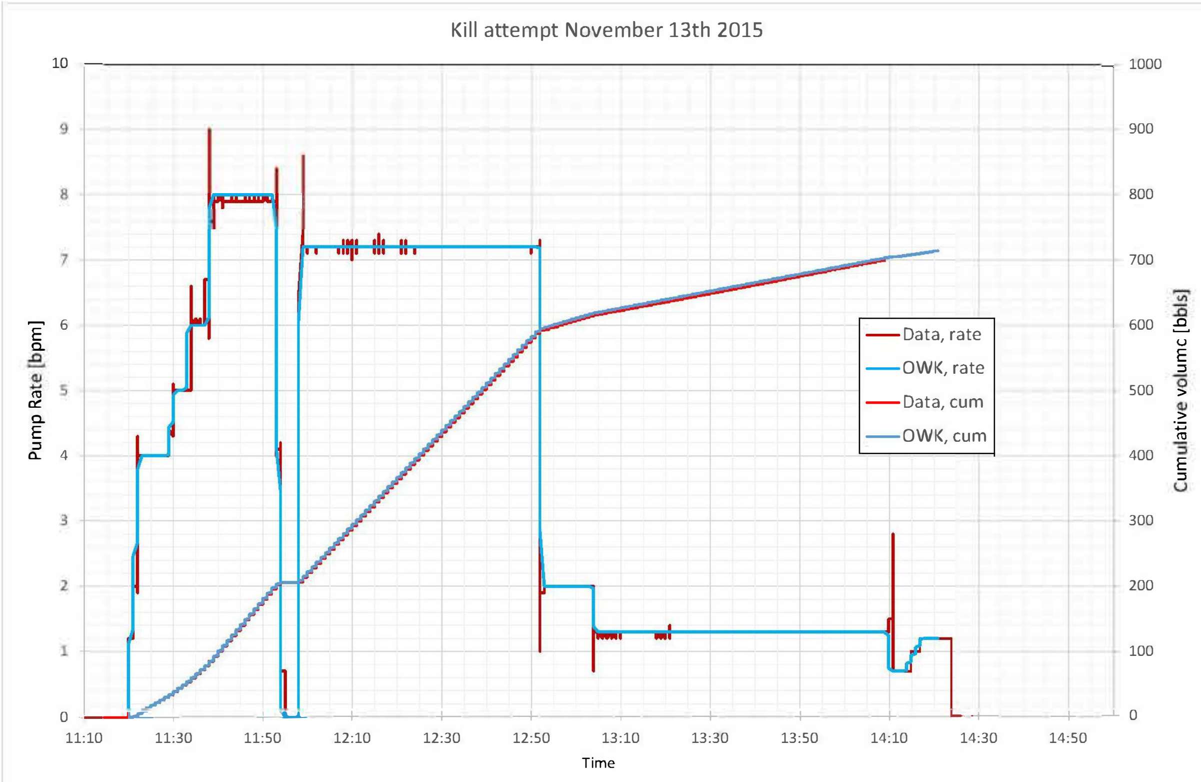

Figure 6.2: Pump rates during pumping operation November 13th 2015

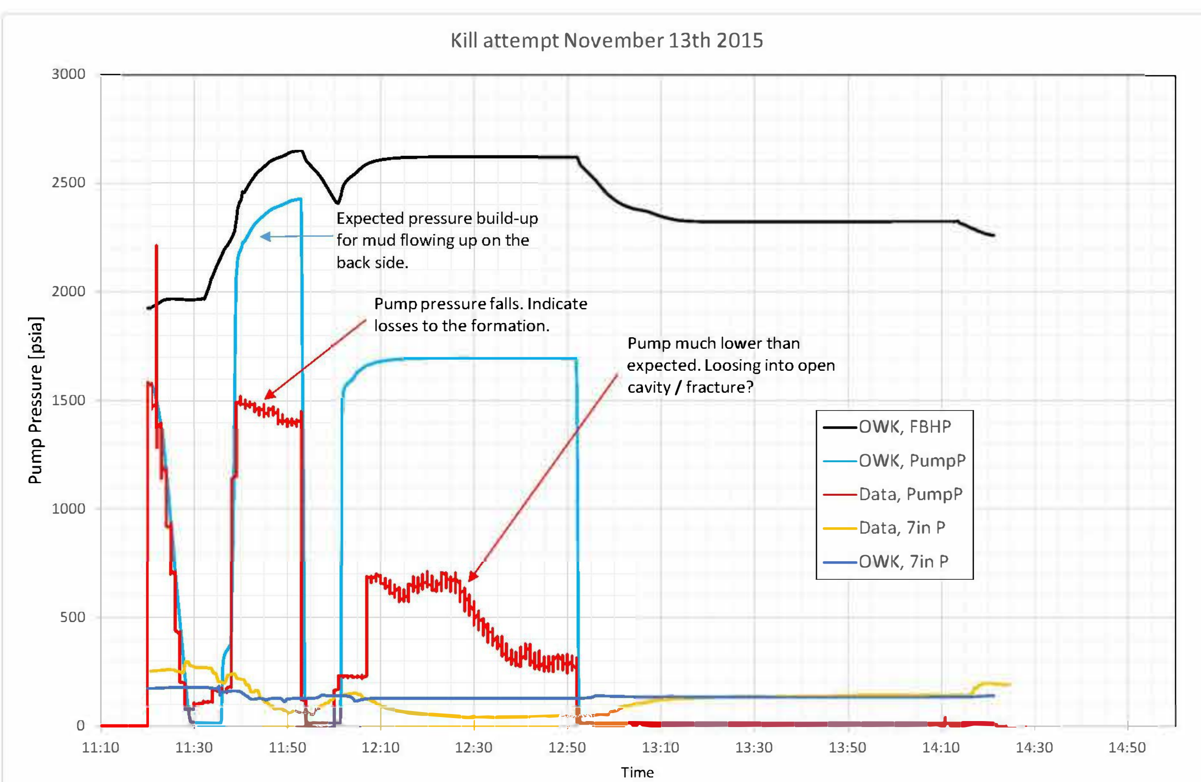

Figure 6.3: Pressures during pumping operation November 13th 2015

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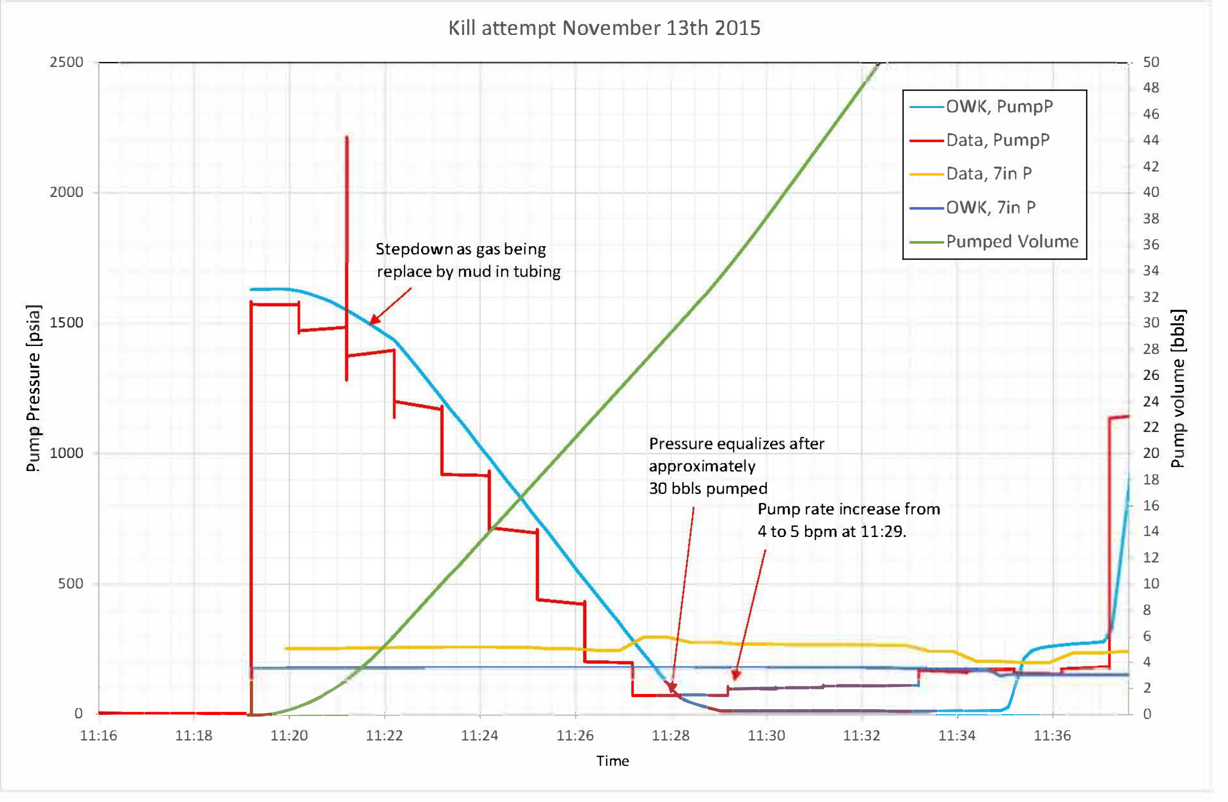

Figure 6.4: Pressures step-down during operation November 13th 2015

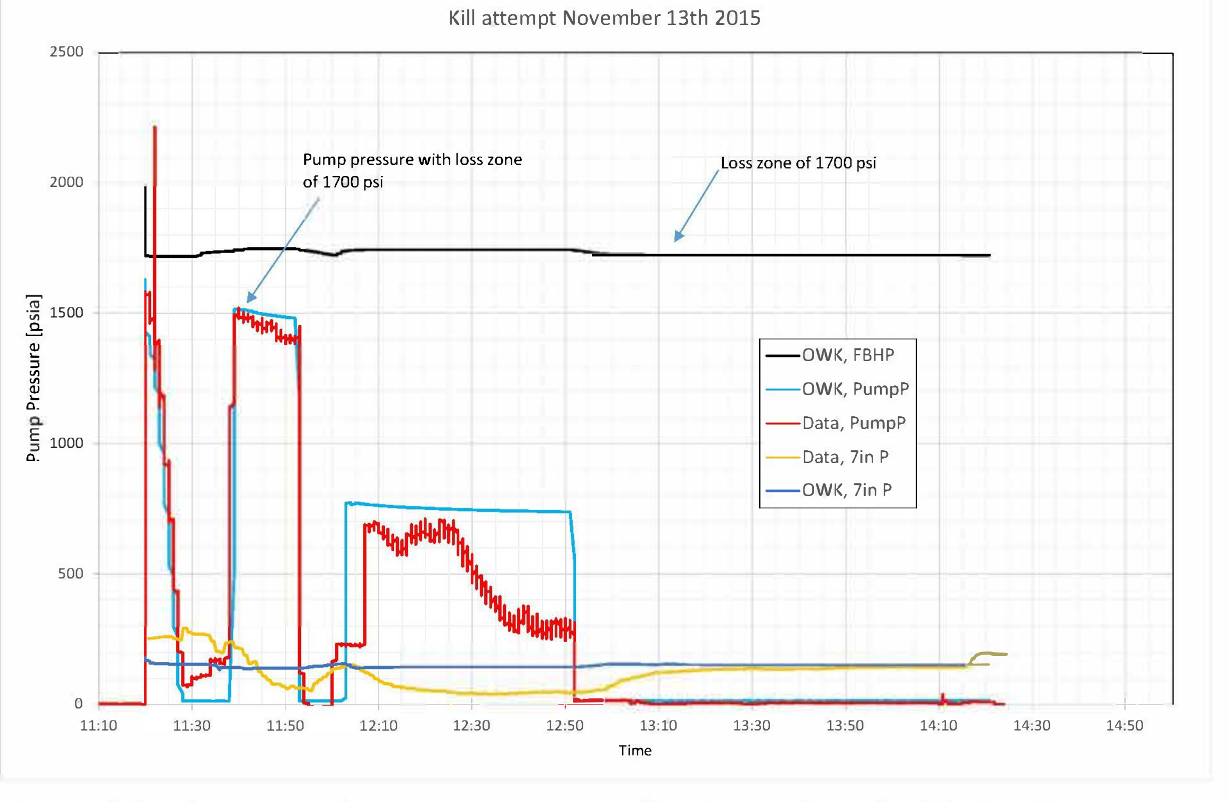

Figure 6.5: Pressures during pumping operation November 13th 2015, with losses

6.5 Pumping operation, November 15th 2015

On this pumping operation, a constant rate of 8.1 bpm using 9.76 ppg mud was maintained and the pump pressure averaged out at around 1550 psi with 1330 psi on the 2 ⅞" pressure gauge. This indicates that fluid exits at the bottom at a pressure of 1500 psi based on the pressure drop down the tubing. This exit pressure is even lower than the initial exit pressure calculated for the November 13th 2015 pump job. For a typical pump operation where the mud is replacing the gas on the back side (in the flow path outside of the 2 ⅞" tubing), the pressure would increase, and not decrease.

On this job, however, a slight increase in pump pressure is observed between 10:48 and 11:00 hrs. The pump rate is constant, and the increase is an indication of increased bottomhole pressure. As is expected if mud is replacing gas in the annulus. At 11:00, a batch of heavy 17 ppg fluid is pumped at the same rate (8.1 bpm), and the pump pressure drops.

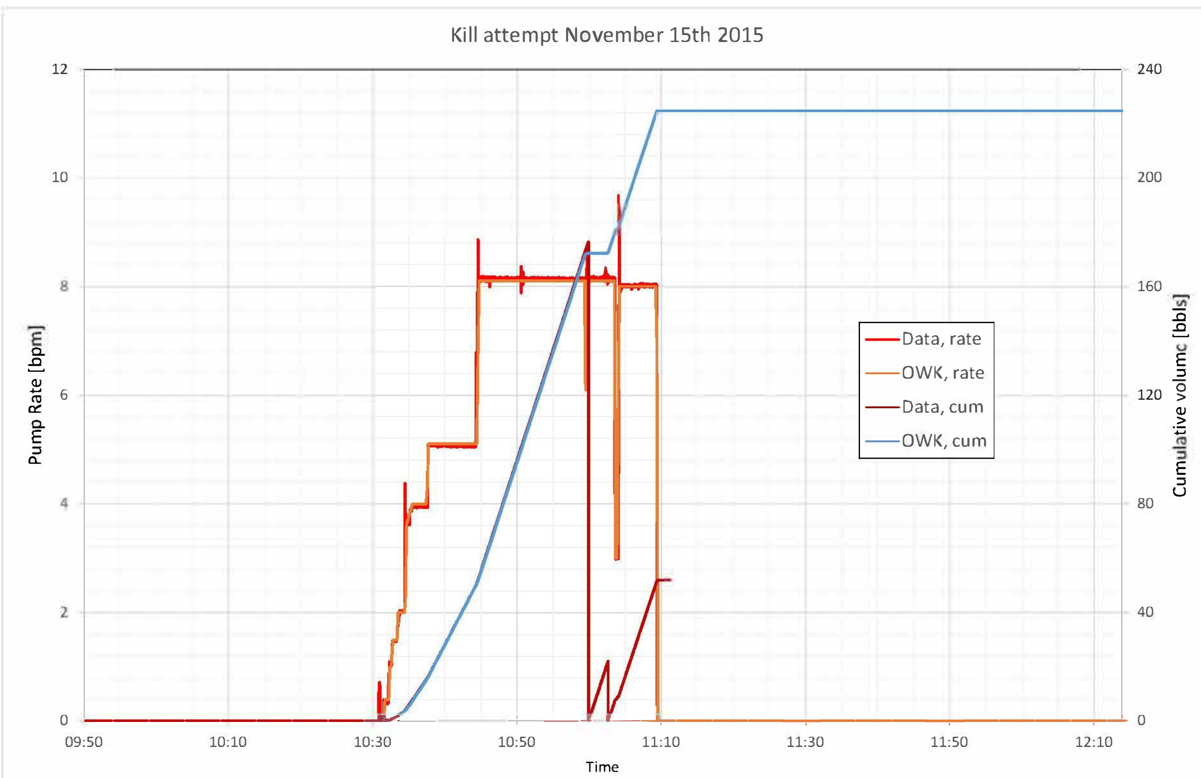

Figure 6.6: Pump rates during pumping operation November 15th 2015

AC_BLD_0076318

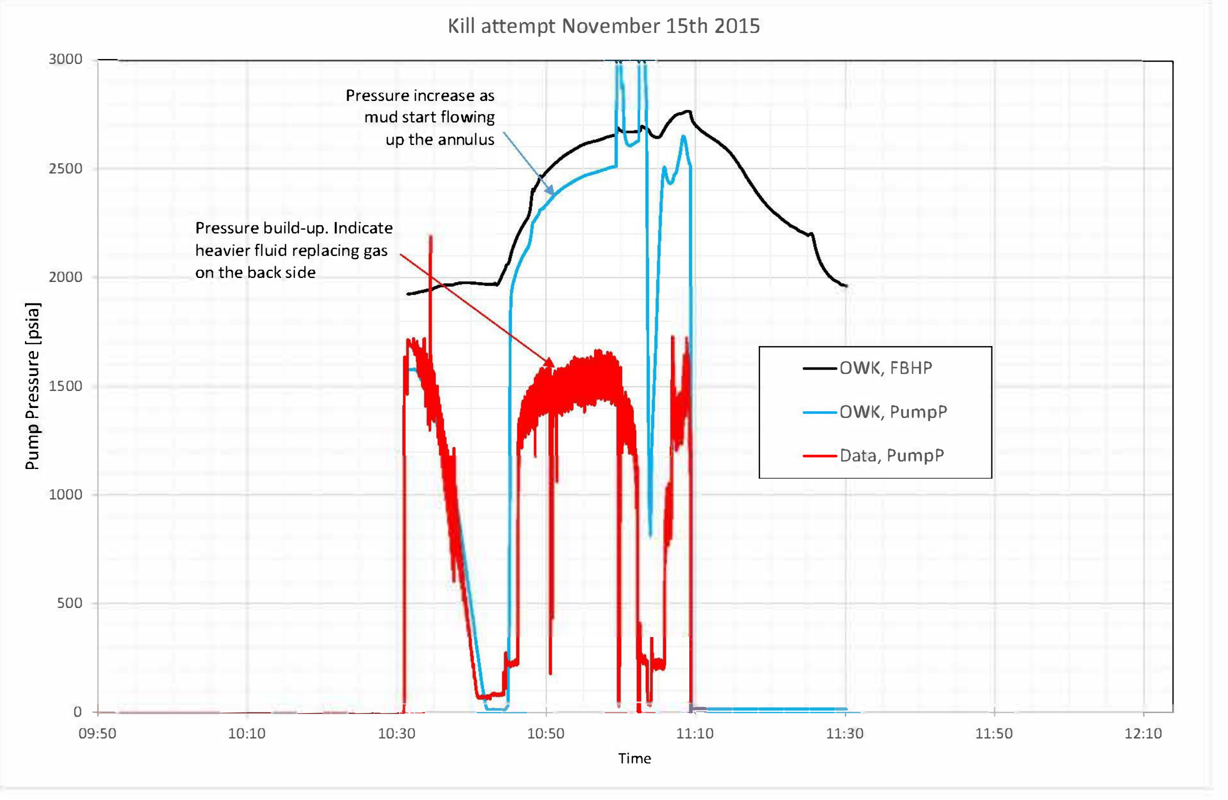

Figure 6.7: Pressures during pumping operation November 15th 2015

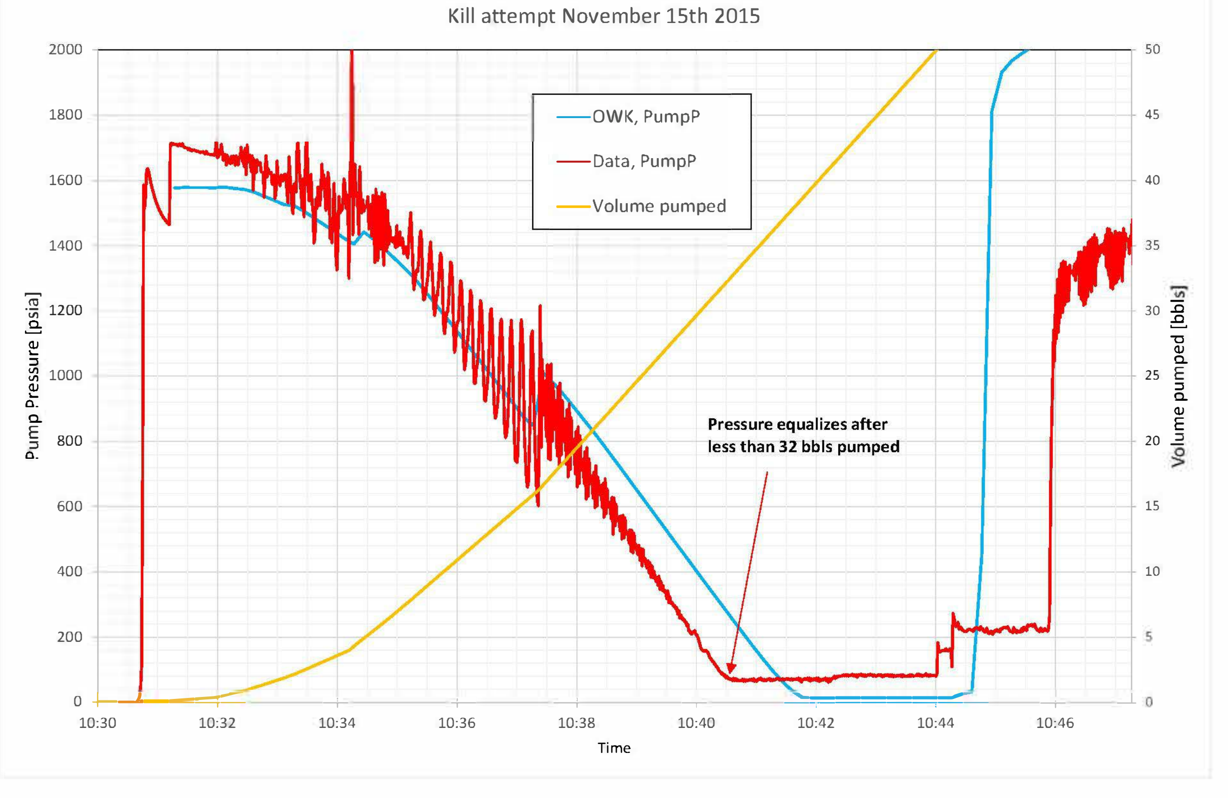

Figure 6.8: Pressure step-down during pumping operation November 15th 2015

6.6 Pumping operation, November 18th 2015

On November 18th 2015, 8.9 bpm using 9.6 ppg mud was pumped where the pump pressure never exceeded 2000 psi. Between 10:37 hrs and 10:41 hrs, a 35 bbls of 18 ppg mud pill was pumped. The pressure at the 2 ⅞" tubing fluctuates around 1650 psi on average. This corresponds to an exit pressure at the bottom of the 2 ⅞" tubing of 1000 psi, a further reduction in the bottom hole pressure compared to the previous jobs.

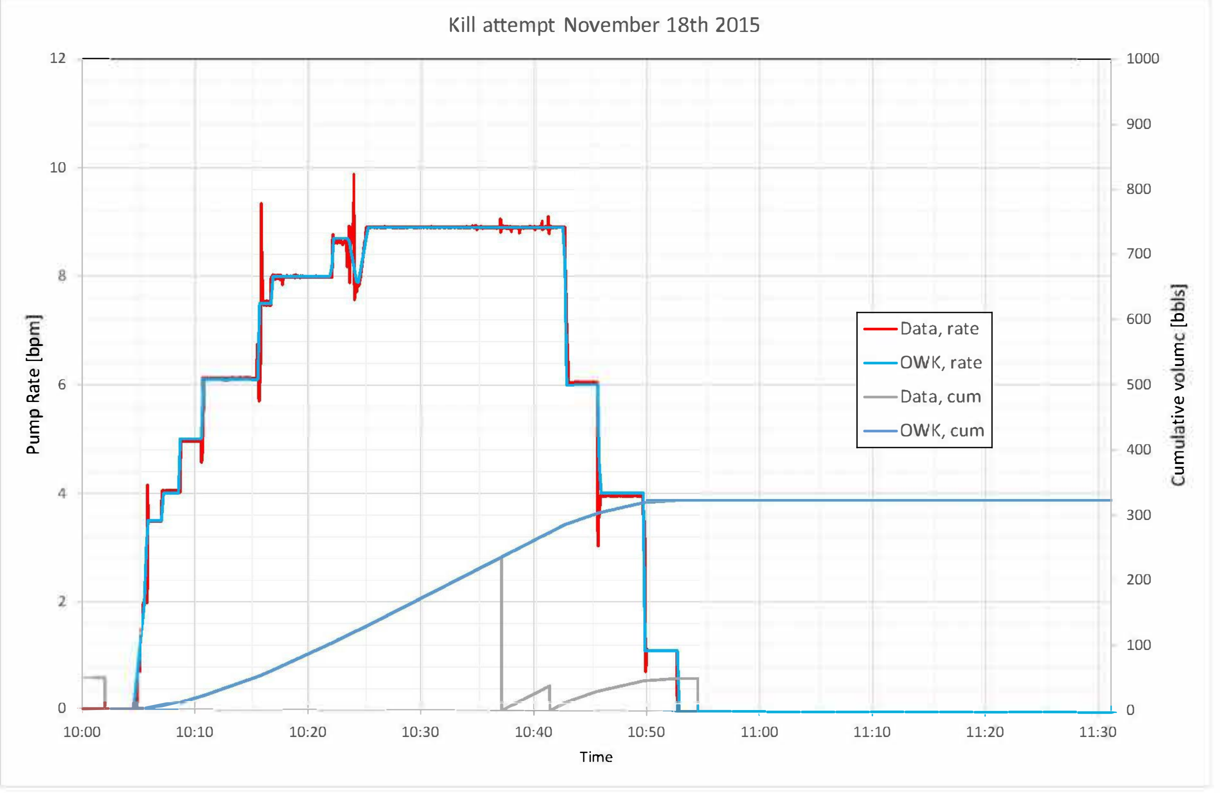

Figure 6.9: Pump rates during pumping operation November 18th 2015

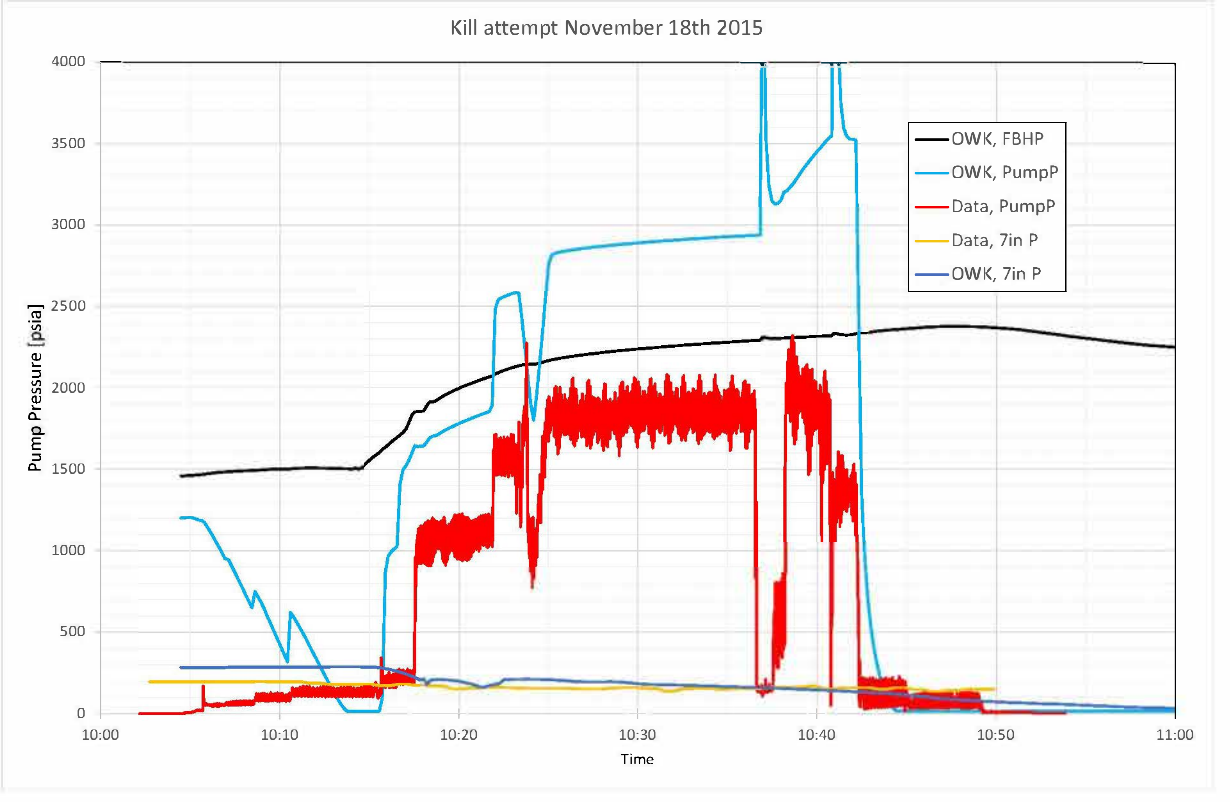

Figure 6.10: Pressures during pumping operation November 18^h 2015

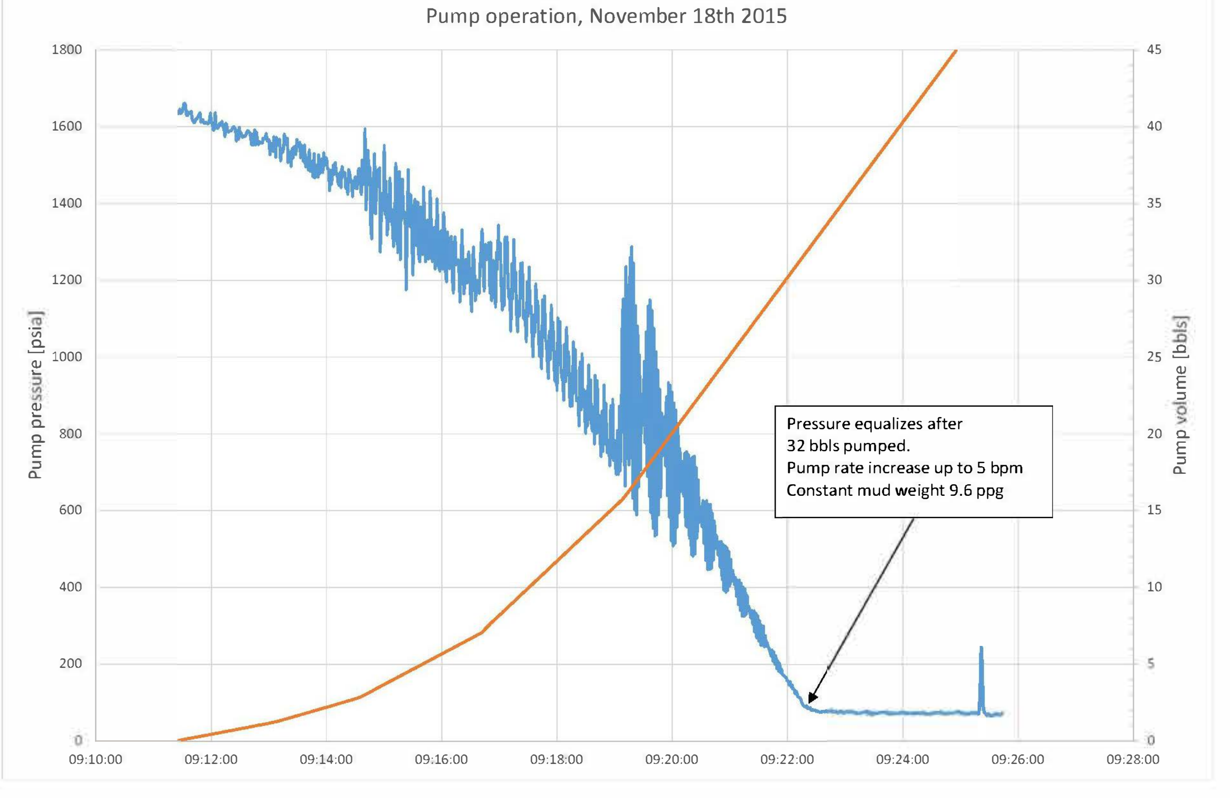

Figure 6.11: Pressure step-down during pumping operation November 18th 2015

6.7 Pumping operation, November 24th 2015

On November 24th 2015, a constant rate of 12.1 bpm of 8.5 ppg fluid was maintained at a constant pump pressure of 4100 psi. The pressure at the top of the tubing was 3400 psi. This implies a very low exit pressure at the bottom of the tubing if the fluid is assumed to be flowing inside the tubing all down to 8381 ft.

The pressure drop from surface down to the end of the 2 ⅞" tubing at 8381 ft is 3300 psi, and hence the fluid exit pressure is only 100 psi.

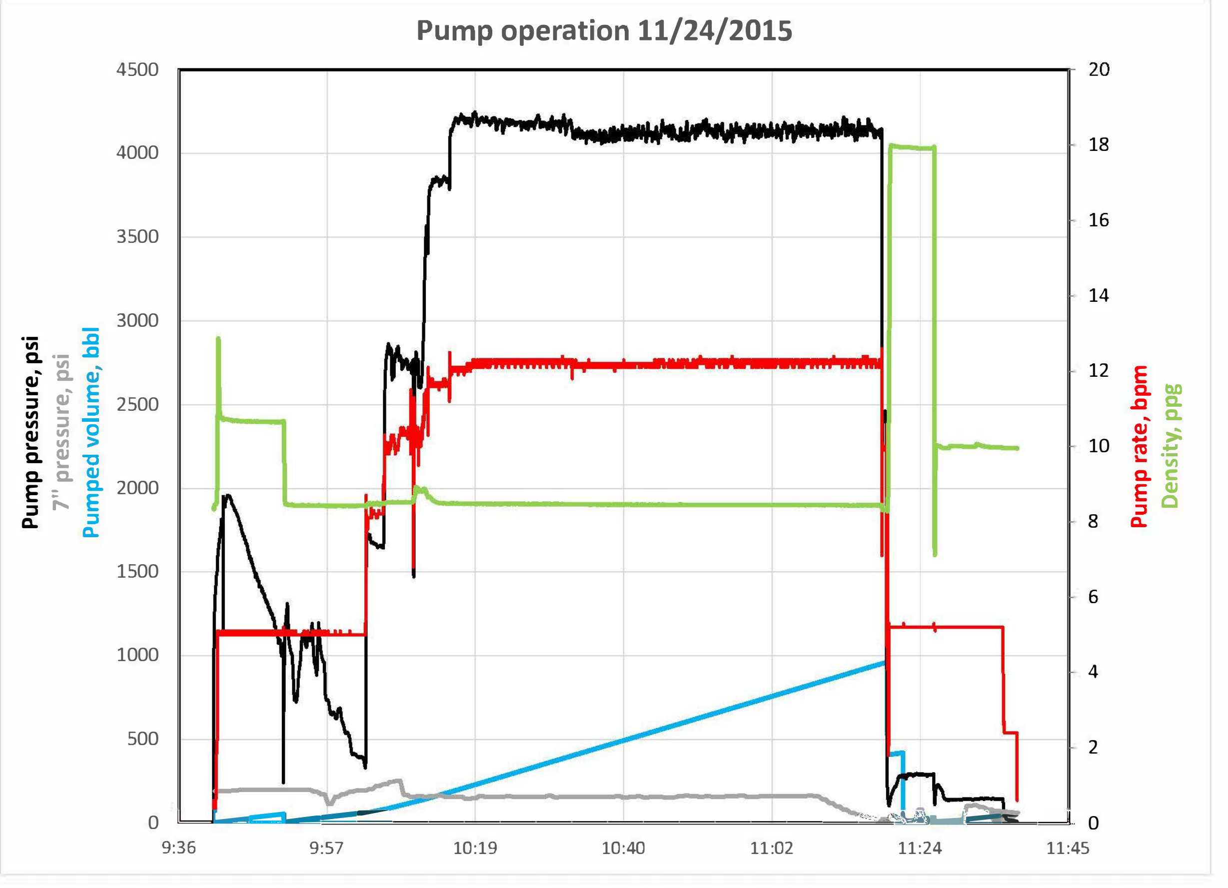

Figure 6.12: Pumping operation on November 24th 2015

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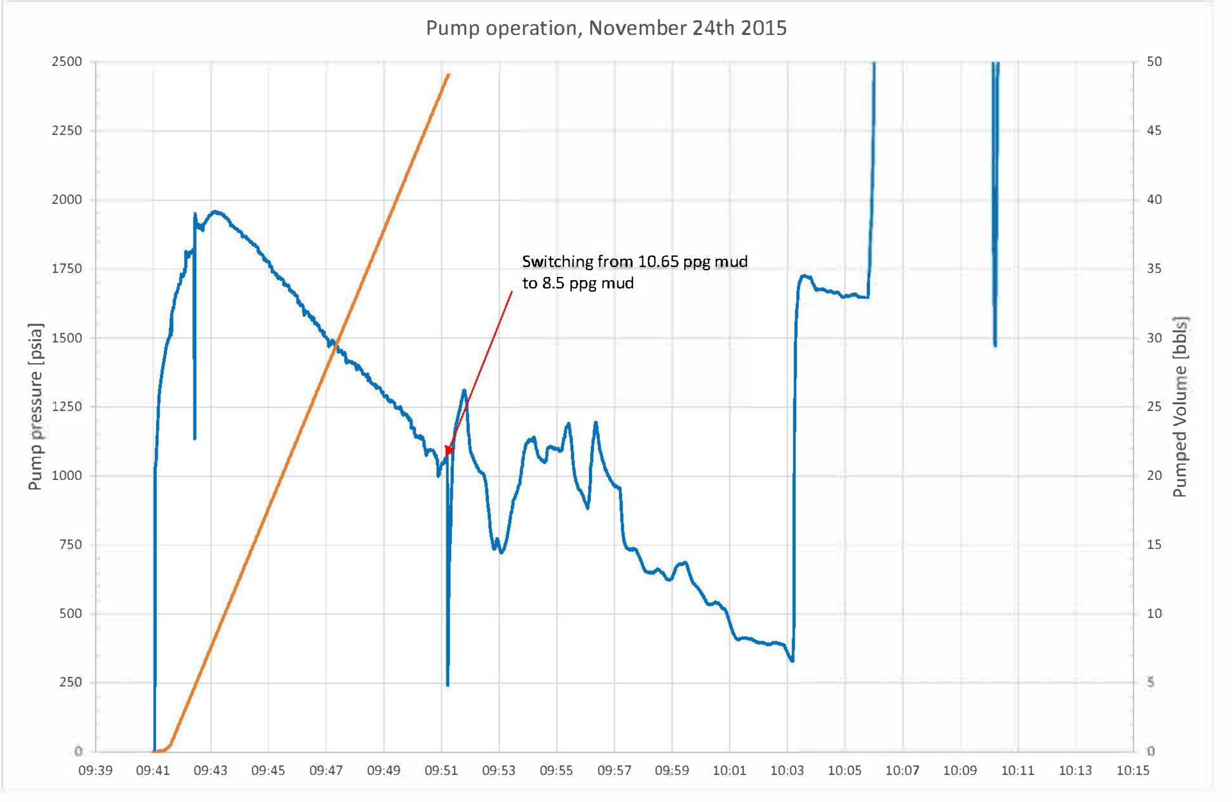

Figure 6.13: Pressure step-down on November 24th 2015

6.8 Pumping operation, November 25th 2015

On November 25th a constant rate of 12.2 bpm of 8.5 ppg fluid was pumped with a pump pressure of 4200 psi, almost similar conditions as the November 24th job.

AC_BLD_0076323

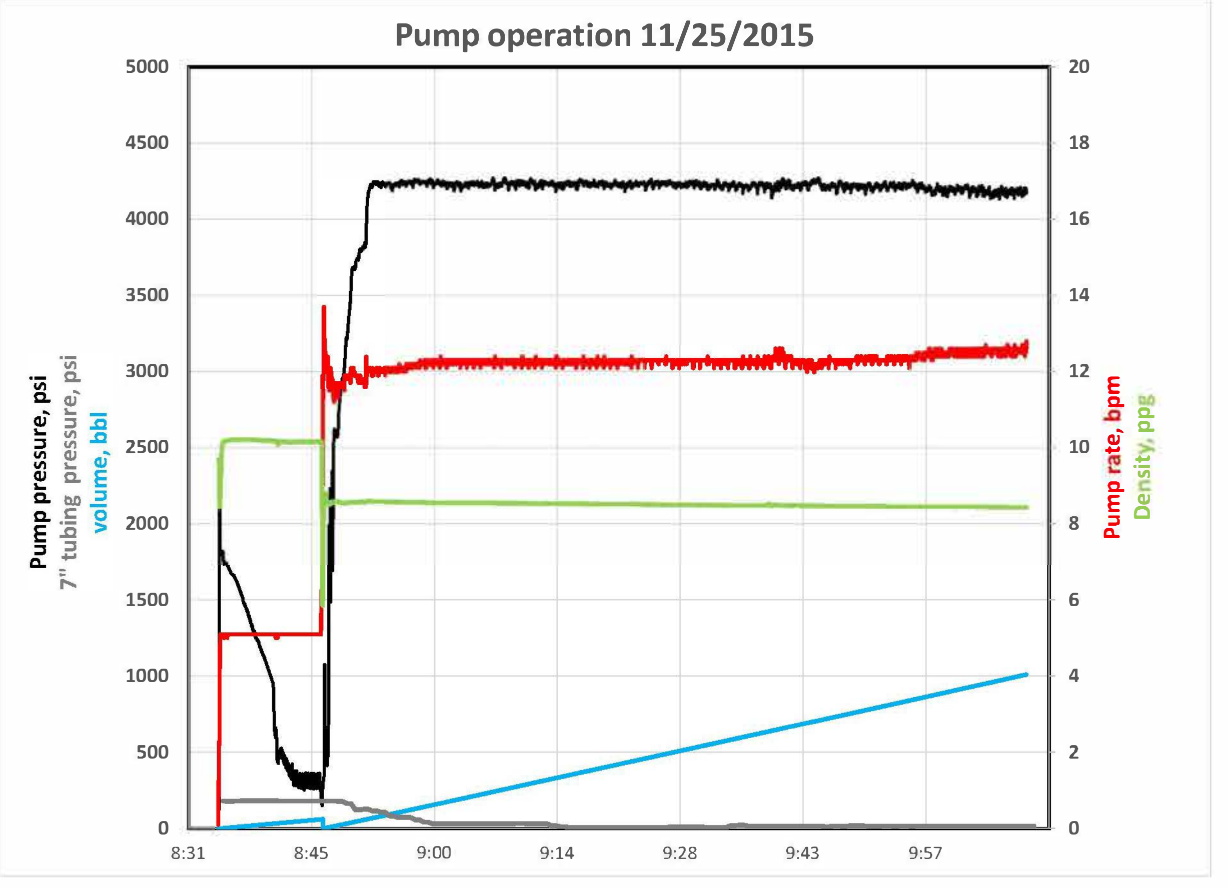

Figure 6.14: Pumping operation on November 25th 2015

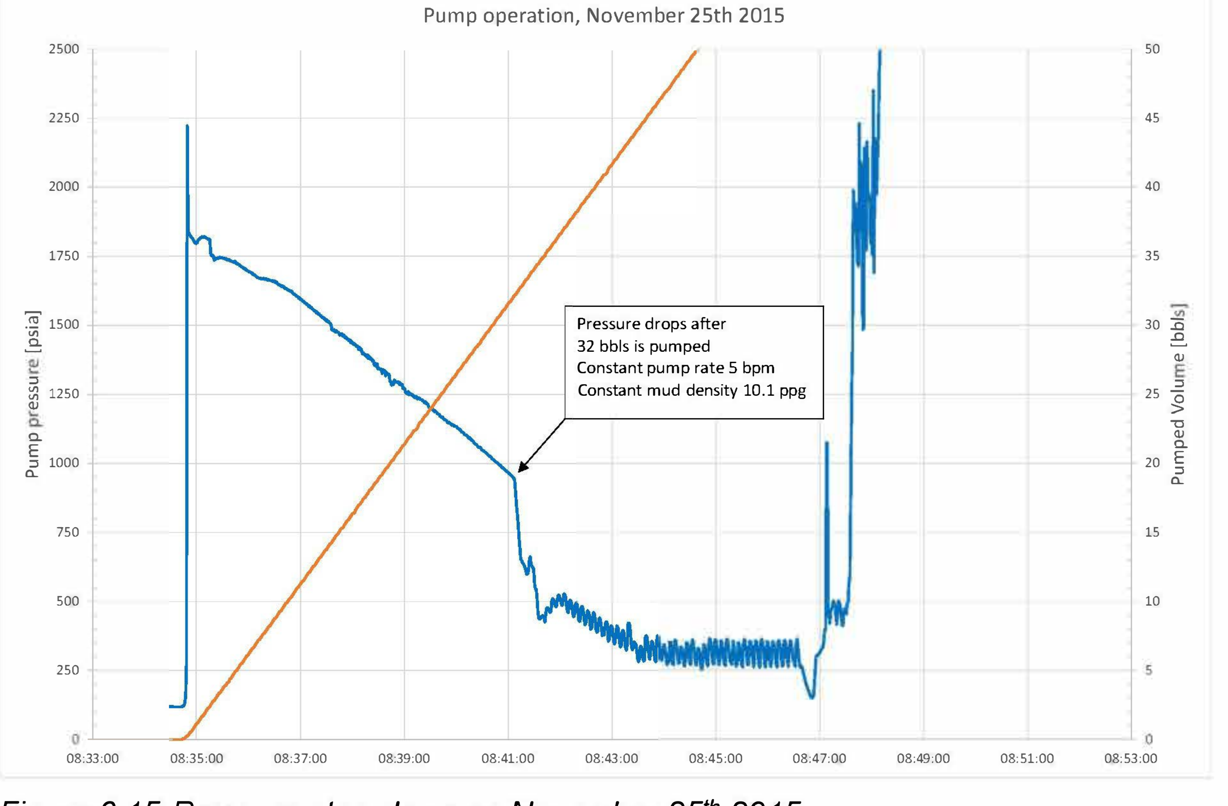

Figure 6.15: Pressure step-down on November 25th 2015

6.9 Pressure buildup after kill jobs

After every kill job, the tubing pressure started to increase and reached a stable high value between 1600 and 1700 psi. The pressure build-up rate however, increased after some of the attempts, see Figure 6.16.

Whilst the tubing pressure was high, less response was seen on the pressure gauge monitoring the 7" x 2 ⅞" annulus.

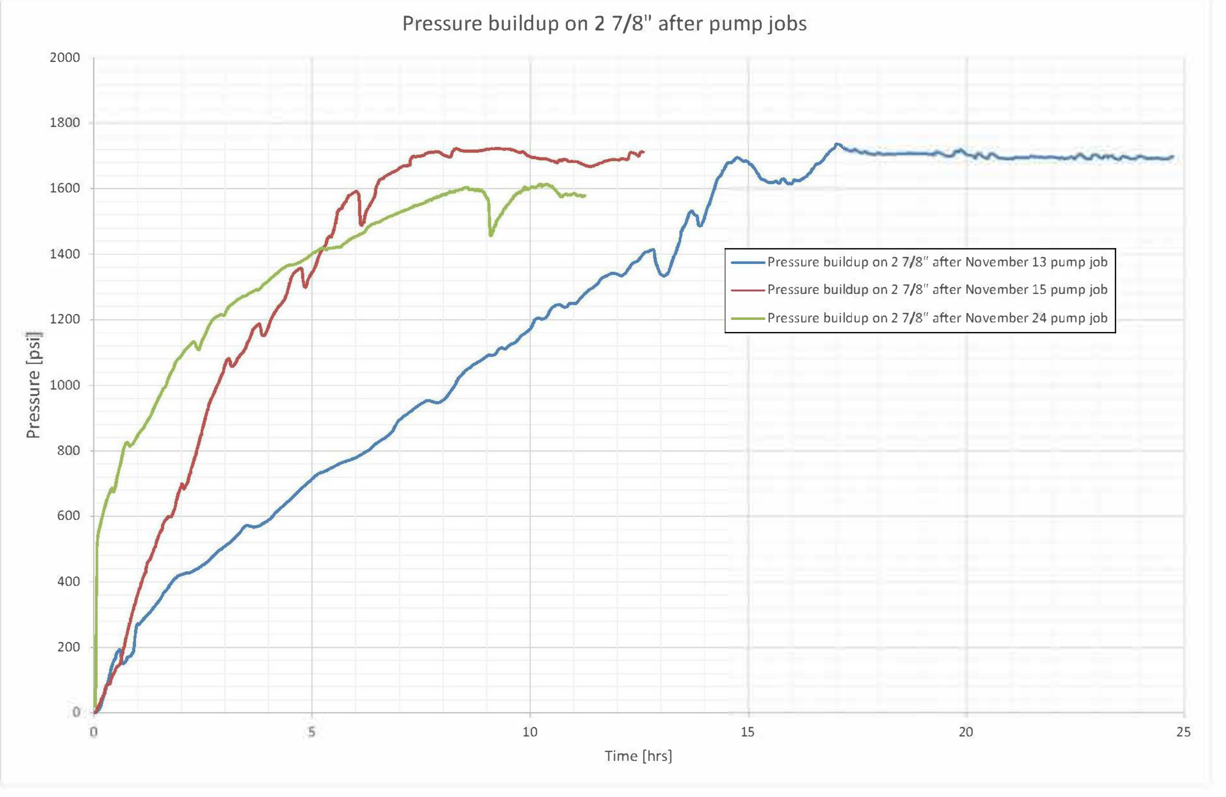

Figure 6.16: Pressure build-up on tubing after kill jobs

6.10 Summary of pumping operations in November

The following table shows the pump pressure, the pressure at the top of the 2 ⅞" tubing, and the calculated exit pressure at the bottom of the tubing assumed the flow is exiting at the bottom of the 2 ⅞" tubing at 8381 ft. The table shows that after each kill attempt, the fluid will be exiting at a lower pressure compared to previous pump jobs. The reservoir pressure during these kill attempts was estimated to be around 3000 psi.

Based on these calculations, a theory of a shallow leak in the tubing was introduced. This could explain the low pump pressure, the fact that the well was not killed during pumping operations (which then was off-bottom), explains pressure drop during pumping, explains falling pressure during pumping and could also explain that mud was coming back after a while after pumps were stopped.

The falling pressure after every kill attempt could indicate that an initial restriction was reduced. A restriction in the flowpath would cause higher tubing pressure initially compared to after the restriction was removed, see illustration in Figure 6.17.

However, as illustrated in the previous section (Chapter 6.9), the tubing pressure returned to more or less the same pressure (1600 – 1700 psi) after the kill attempts. This is not supporting a reduction in a potential annulus restriction after every kill attempt.

Table 6.2: Calculated pressure at the bottom of the 2 ⅞" tbg during kill attempts

Date	Pump pressure [psia]	Pressure at 2 ⅞" tubing [psia]	Pump rate [bpm]	Fluid Density [ppg]	Exit pressure [psi]
November 13	700	700	7.2	9.6	1700
November 15	1550	1330	8.1	9.76	1500
November 18	2000	1650	8.9	9.6	1000
November 24	4100	3400	12.1	8.5	100
November 25	4200	na	12.2	8.5	100

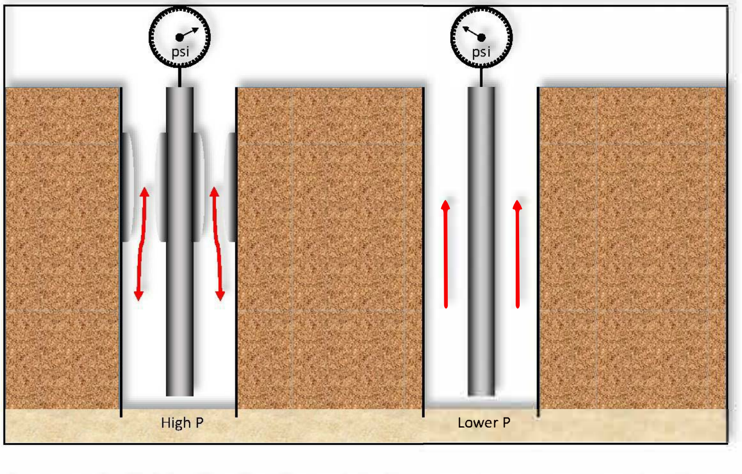

Figure 6.17: Effect of restriction on pressure reading

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On January 22nd 2016, a caliper log was run in the SS25 tubing between 3000 and 6000 ft, and no hole in the tubing were detected for this interval. A leak in the tubing between 0 and 3000 ft and below 6000 ft cannot be ruled out.

6.11 Pumping operation, December 22nd 2015

The last pumping operation before it was decided to cease further surface kill attempts, was performed on December 22nd 2015. At this date, the reservoir pressure is estimated to be 2050 psi, see Figure 2.3. Prior to the pumping operation, the tubing head pressure was 1215 psi. The flowing bottom hole pressure (FBHP) is estimated to be 1480 psi based on simulations. After pumping 1.5 bbls of glycol down the tubing, the pressure dropped to 1140 psi. According to the volume inside of the tubing, 1.5 bbls equals a length of 266 ft. Simulations predicted a similar pressure drop (110 psi).

A total of 300 bbls of 15.1 ppg WBM was pumped and the pump rate varied between 5.1 and 5.8 bpm, see Figure 6.18. The pump pressure followed a decline during pumping of the first 13 bbls, but the pump pressure gauge showed severe oscillations with an initial amplitude of over 1000 psi, see Figure 6.20. After 70 bbls were pumped, mud/oil mist was reported in the crater. After 300 bbls were pumped, the pumps were shut down due to rocking of wellhead and unloading mud. According to Boots & Coots representatives, the volumes of mud at surface were less compared to previous kill attempts due to the heavy mud being pumped. The well continued to unload dehydrated/clabbered mud.

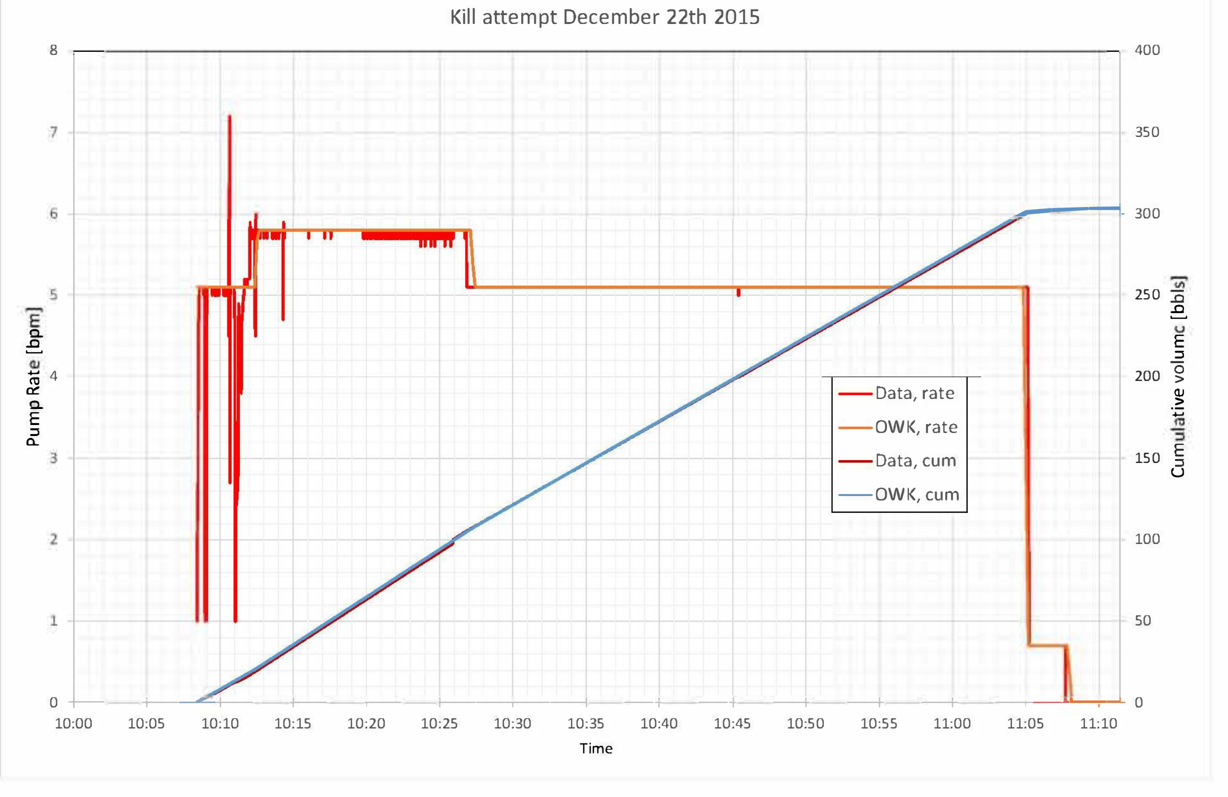

Figure 6.18: Pump rates during pumping operation December 22nd 2015

AC_BLD_0076327

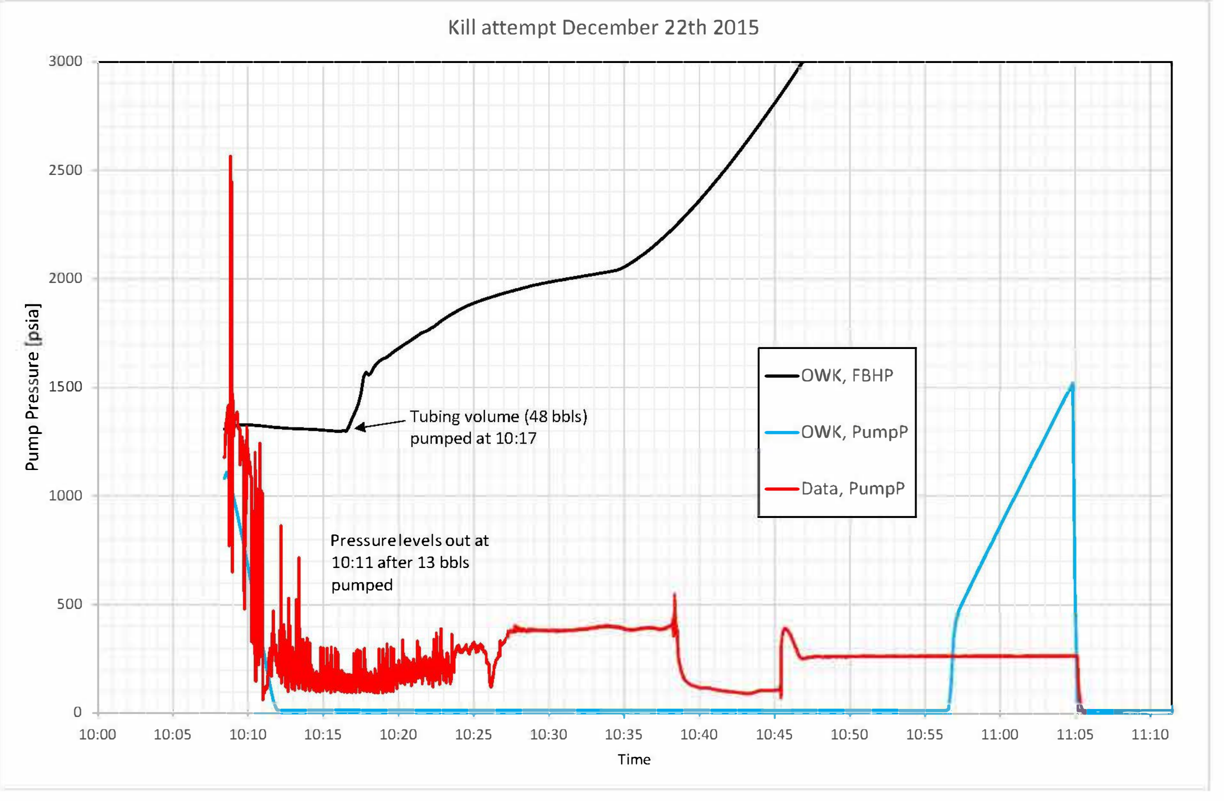

Figure 6.19: Pump rates during pumping operation December 22nd 2015

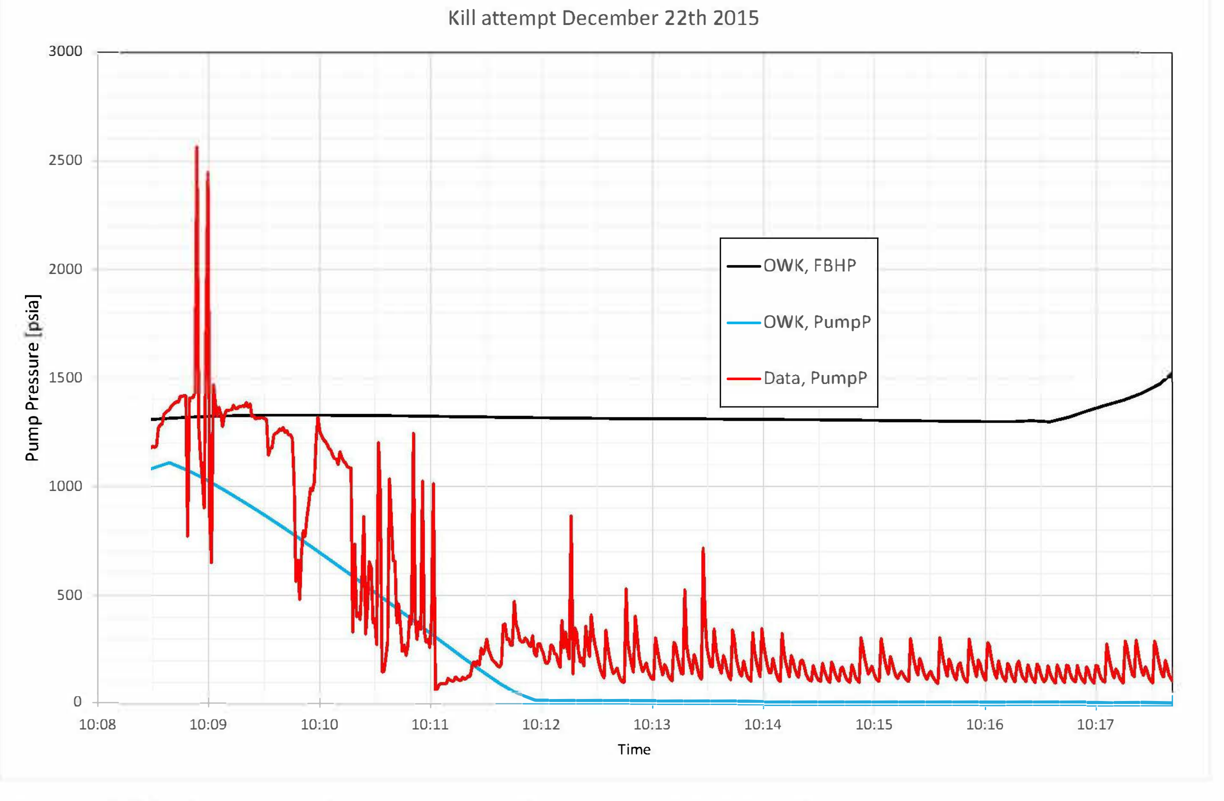

Figure 6.20: Pressure step-down on December 22nd 2015

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7. Relief Well Kill Simulations

7.1 General

Simulations have been performed to evaluate the kill operation pumping kill mud through the relief well 1, RW1 (P39A). The intersection point is planned at 8491 ft MD referenced the SS25 rkb. The planned mud weight will be 9.0 ppg with a yield point of 27 lb/100 ft.

At the time of intersection, the reservoir pressure will be around 1150 psi (see Figure 2.3), the flowing bottomhole pressure around 700 psi, and there will be a huge pressure differential between the wells. Prior to intersection, the pressure in RW1 well will be 3820 psi based on 9.0 ppg mud, hence an overbalance of 3120 psi.

There is therefore expected that severe losses will occur during the pumping operation.

The RW1 (P39A) well is spudded 930.5 ft south and 1151 ft east of SS25. Total horizontal distance is 1480 ft and the RW1 elevation is 299 ft below the SS25 ground level.

Figure 7.1: RW1 (P39A) spud location

Figure 7.2: Locations of Relief Well 1, SS25 and backup Relief Well 2 Pad

7.2 Relief well trajectory

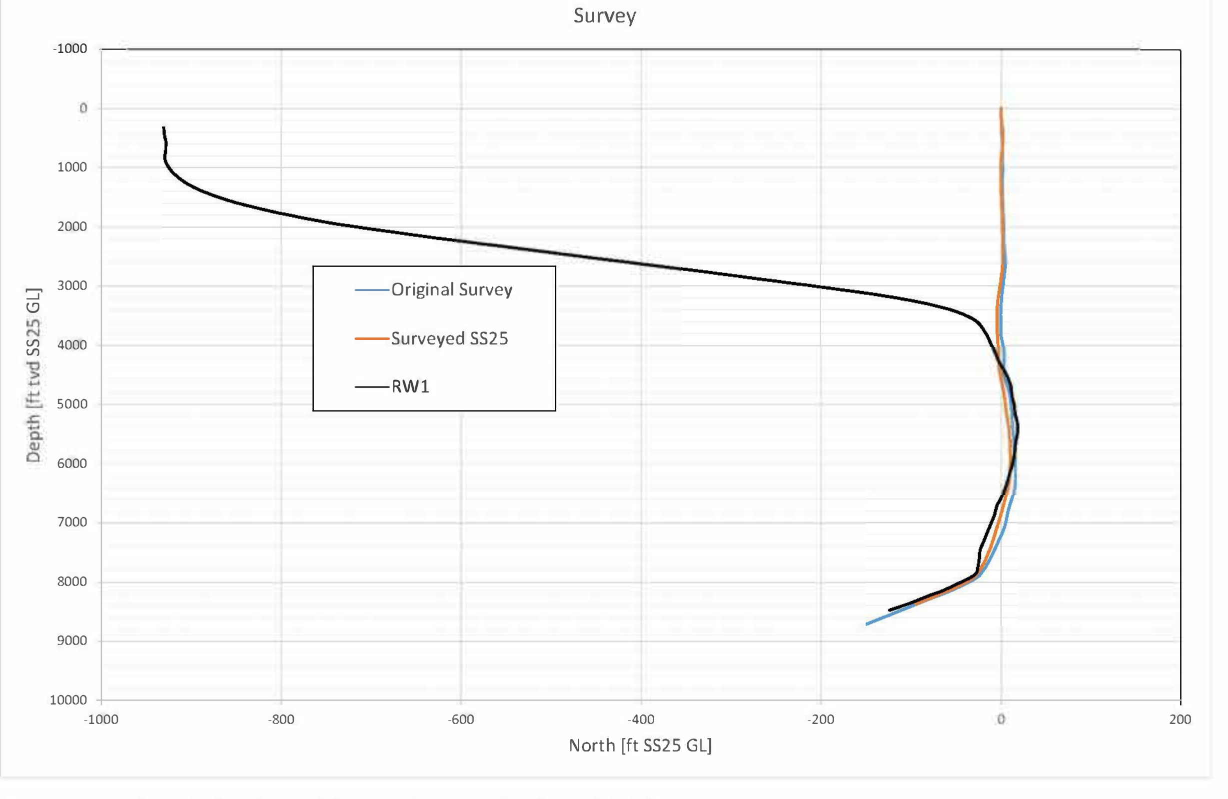

Figure 7.3: Relief well trajectory, North – TVD

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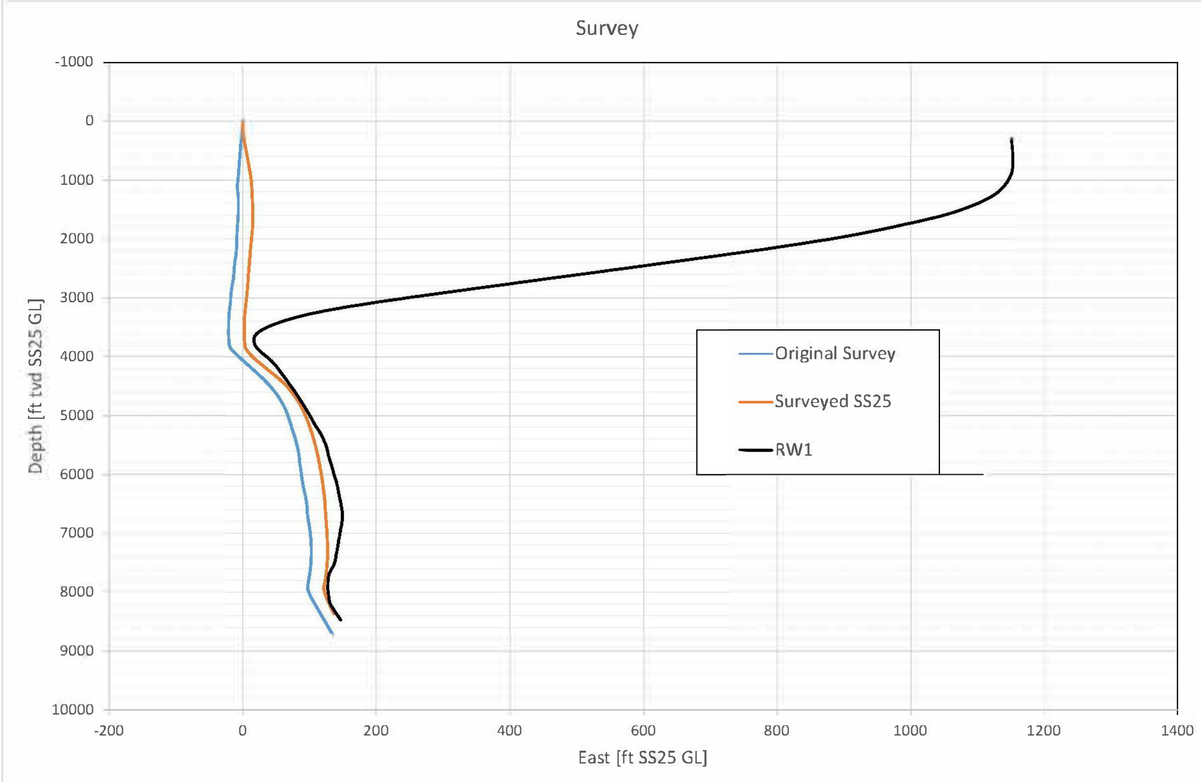
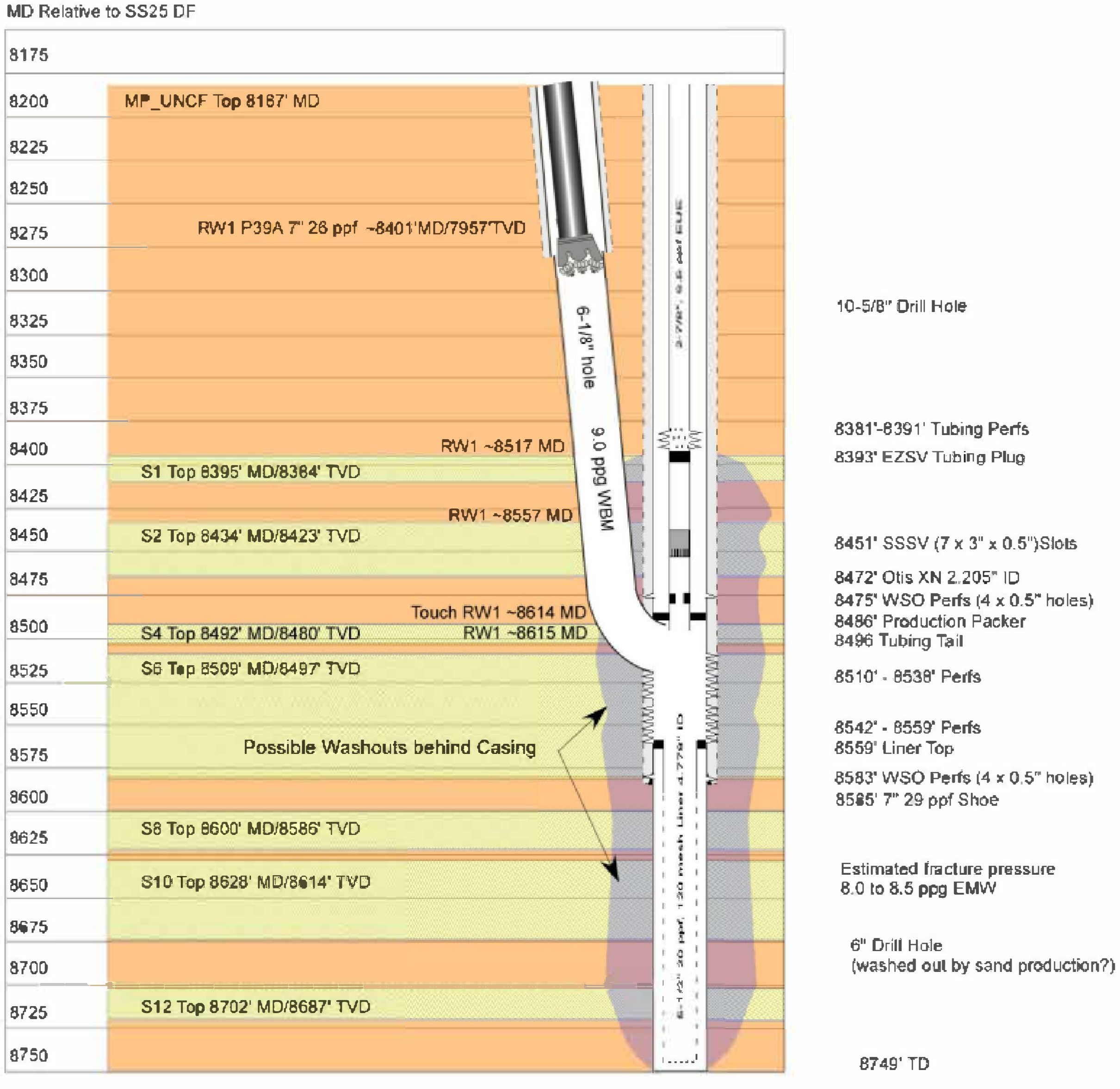


Figure 7.4: Relief well trajectory, East – TVD

7.3 Relief well configuration

The relief well is designed using a 9 ⅝" 47# casing (id=8.681 in) set at 3682 ft mD and a 7" 26# liner (id=6.276 in) set at 8401 ft MD (7956 ft tvd). The top of the liner (TOL) is 300 ft inside of the 9 ⅝" casing. A 6 ⅛" hole is drilled using a 216 ft of 4 ¾" BHA when intersecting the SS25, see Table 7.1. The bit has two nozzles, 20/32" and 22/32".

The length of the relief well is 8625 ft MD.



Open hole volume sensitivity
below 7" Shoe

20" Avg Dia = 59 bbls
40" Avg Dia = 250 bbls
60" Avg Dia = 568 bbls
80" Avg Dia = 1015 bbls
100" Avg Dia = 1588 bbls

Open hole volume sensitivity
8475' WSO Perf to 7" Shoe

20" Avg Dia = 38 bbls
40" Avg Dia = 166 bbls
60" Avg Dia = 379 bbls
80" Avg Dia = 679 bbls
100" Avg Dia = 1063 bbls

Open hole volume sensitivity
8395' S1 Top to 7" Shoe

20" Avg Dia = 65 bbls
40" Avg Dia = 286 bbls
60" Avg Dia = 655 bbls
80" Avg Dia = 1172 bbls
100" Avg Dia = 1837 bbls

Constructed Volumes

4.2 bbls inside 5.5"
1.1 bbls 6" x 5.5" Annulus
2.7 bbls Packer - Liner top
266 bbls 7" x 2-7/8" above Packer
15 bbls 7" annulus to 470' Hole
45.2 bbls inside 2-7/8" to EZSV
70.1 bbls 11-3/4" x 7" Annulus
113 bbls 16" x 11-3/4" (drilled hole)

Total Volume below packer: 8 bbls
Total Volume above packer: 311 bbls

Figure 7.5: Schematic of relief well RW1 intersection with SS25

Table 7.1: RW1 4 ¾" BHA

COMPONENT DATA										
Item #	Description	Serial Number	OD (in)	ID (in)	Gauge (in)	Weight (lbpf)	Top Connection	Length (ft)	Cumulative Length (ft)
1	Hybrid - PDC / Bicone	7039522	4.750	1.500	6.125	54.37	P 3-1/2" REG	0.80	0.80
2	4 3/4" SperryDrill Lobe 7/8 - 3.8 stg	10450025	4.750	2.820		46.73	B 3-1/2" IF	23.56	24.36
	Stabilizer				6.000				
3	NM Welded Blade Stab BFF	DHS470904	4.813	2.250	6.000	48.45	B 3-1/2" IF	4.86	29.22
4	Non Mag Flex Gyro Collar	1164773	4.688	2.625		40.38	B 3-1/2" IF	28.60	57.82
5	4 3/4" PWD	90463607	4.750	1.250		47.90	B 3-1/2" IF	9.11	66.93
6	4 3/4" Slim Phase 4 Collar	90453569	4.750	1.250		48.20	B 3-1/2" IF	24.52	91.45
7	4 3/4" TM/DM 350 HOC	11829548	4.750	2.812		46.10	B 3-1/2" IF	16.86	108.31
8	Screen Sub	11256433	4.750	2.000		49.69	B 3-1/2" IF	7.14	115.45
9	Non Mag Flex Collar	11564359	4.750	2.250		46.64	B 3-1/2" IF	31.13	146.58
10	Non Mag Flex Collar	11623703	4.750	2.250		46.84	B 3-1/2" IF	31.05	177.63
11	PBL Sub	475BP163	4.750	1.270		56.07	B 3-1/2" IF	8.12	185.75
12	3-1/2" X 2-1/4" SWDP #26.7 10 jts		3.500	2.250		26.70		300.00	485.75
13	Jars		4.750	2.250		46.84		30.00	515.75
14	3-1/2" X 2-1/4" SWDP #26.7 16 jts		3.500	2.250		26.70		480.00	995.75
							Total	995.75	

7.4 Plan for intersection based on ranging run 28

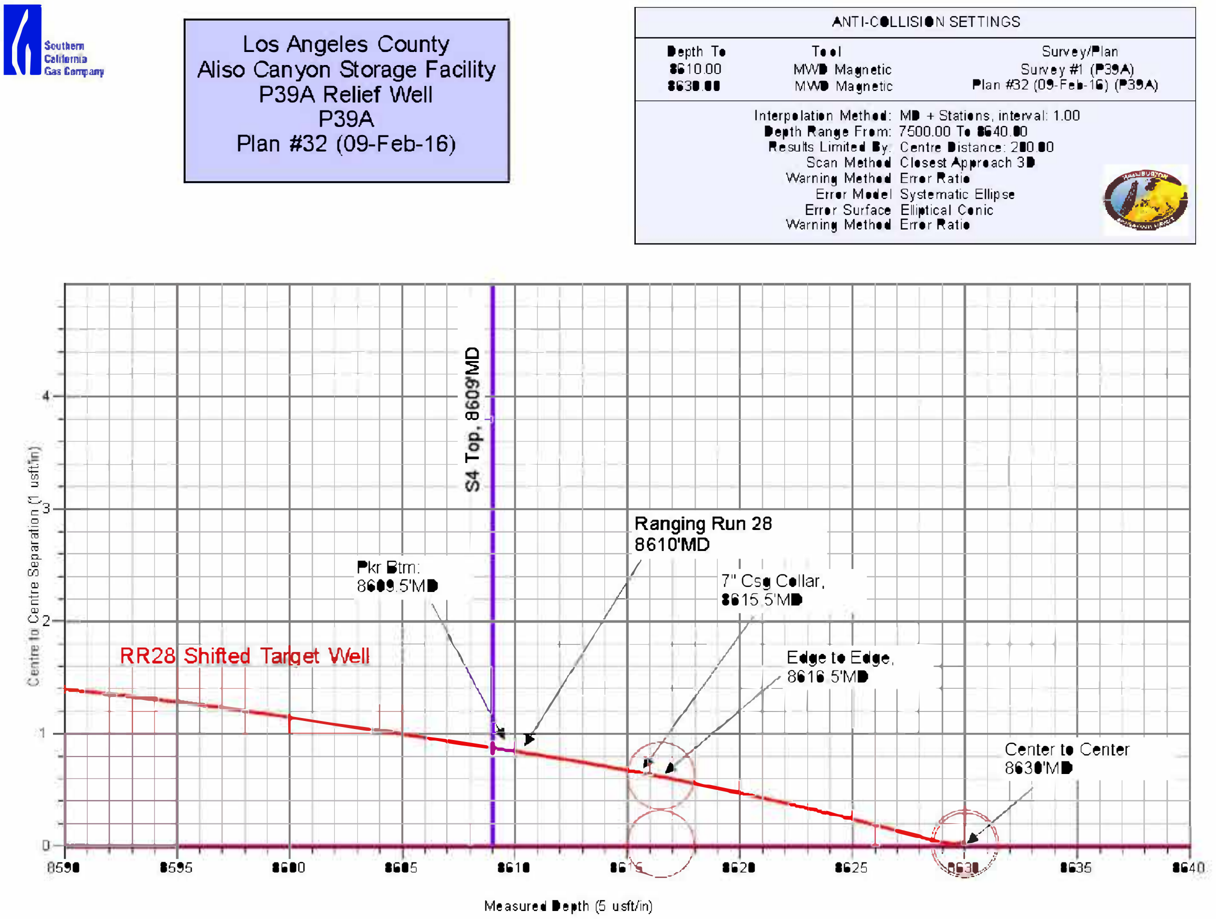


Figure 7.6: Plan for intersection after RR28

7.5 Mud properties

The planned mud weight used for the relief well kill operation is 9.0 ppg mud. The plastic viscosity is 21 cP and the yield point is 27 lb/100 ft².

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7.6 Minimum pump rate avoiding gas migrating into RW

In case of total losses in the relief well following the intersection with the SS25 well flowing from the depleted reservoir, it is important to maintain circulation and hence avoiding gas migrating into the relief well annulus. Direct measurements of gas migration velocities in laboratory experiments and full-scale tests have shown that gas can migrate up a well bore at approximately 6000 ft/hr (see e.g. ref. 2). As a rule of thumb, a velocity of 1 m/s (3.3 ft/s) has been used to avoid rising bubbles through the liquid even for inclined flow. (Which require higher pump velocities compared to vertical flow). In the relief well annulus, this equals a pump rate of 5 bpm in the 7" ln x 3 ½" dp section and 10 bpm in the 9 ⅝" csg x 5" dp section.

Table 7.2: Minimum velocity in relief well annulus avoiding gas migration

	Flow conduit		
	7" ln 26# x 4 ¾" BHA	**7" ln 26# x 3 ½" dp**	**9 ⅝" 47# x 5" dp**
Pump rate	**Velocity**	**Velocity**	**Velocity**
[bpm]	**[ft/s]**	**[ft/s]**	**[ft/s]**
1	1.0	0.6	0.3
2	2.0	1.3	0.7
3	**3.1**	1.9	1.0
4	4.1	2.5	1.4
5	5.1	**3.2**	1.7
6	6.1	3.8	2.0
7	7.1	4.4	2.4
8	8.2	5.1	2.7
9	9.2	5.7	3.1
10	10.2	6.3	**3.4**
11	11.2	7.0	3.7
12	12.2	7.6	4.1
13	13.3	8.2	4.4
14	14.3	8.9	4.8
15	15.3	9.5	5.1

7.7 Static evaluations

The elevation difference between the exit point of the SS25 (ground level) and the RKB of RW1 is 299 ft. This u-tube differential will create a pressure on the relief well assumed SS25 is static and filled with mud. A mud weight of 9.0 ppg will result in a pressure of 140 psia at the RW1 drill floor assumed both wells are filled with mud.

To achieve a static condition with zero pressure both at the SS25 location and at the RW1, the mud column in the SS25 well has to drop 299 ft to equalize this u-tube imbalance.

At the time of intersection, the flowing bottomhole pressure will be approximately 700 psi and the static pressure at bottom of RW1 will be 3820 psi based on 9.0 ppg mud in the relief well. Hence, there will be 3120 psi pressure differential between the SS25 and the RW1 well and heavy losses will occur when communication is established.

The ability to raise mud in SS25 depends on the prevailing fracture gradient in the reservoir. Table 7.3 shows the expected liquid levels in the SS25 well and in the shut-in tubing versus fracture gradient.

Table 7.3: Liquid levels in SS25 after static kill

FG	Annulus	Tubing	THP
ppg	**ft**	**ft**	**psi**
9.0	0	3200	1400
8.5	500	3400	1300
8.0	1000	3700	1200
7.5	1400	4000	1100
7.0	1900	4300	1000
6.5	2400	4600	950
6.0	2800	4900	900

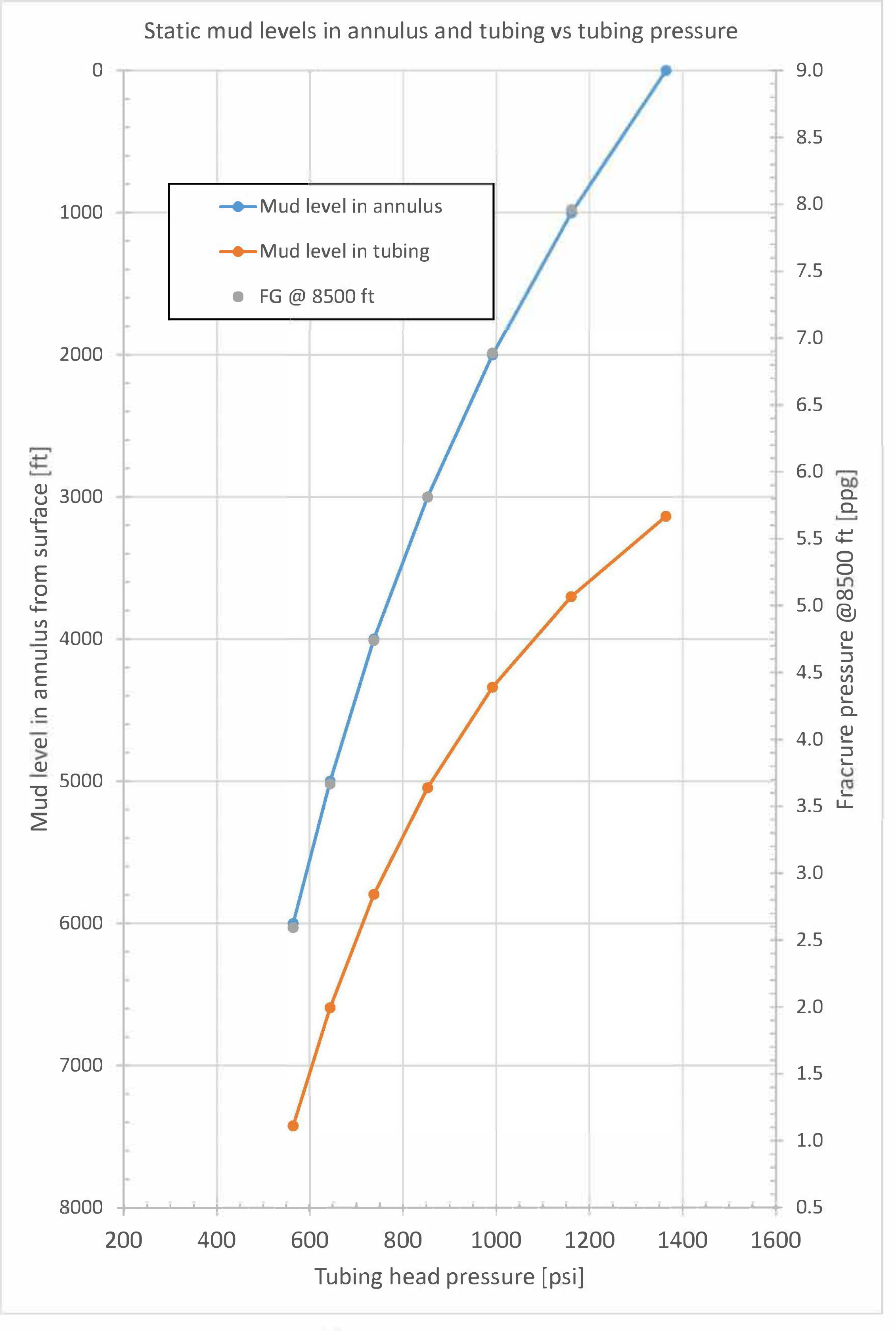


Figure 7.7: Liquid levels in SS25 after static kill using 9.0 ppg mud

7.8 Required kill rate

The rate required to kill the blowout for the depleted reservoir pressure as of January 2016 is less than 10 bpm using 9.0 ppg mud assumed zero losses. Due to the high overbalance, the mud will u-tube into the SS25 well at higher rates than the required and it is just a matter of filling up the SS25 well with mud.

7.9 Conditions in the wellbore prior to intersect

The following conditions have been applied in the simulations prior to intersect. Tubing head pressure 586 psi, flowing bottomhole pressure 704 psi, and reservoir pressure 1150 psi. The tubing head pressure is based on no leak in the tubing.

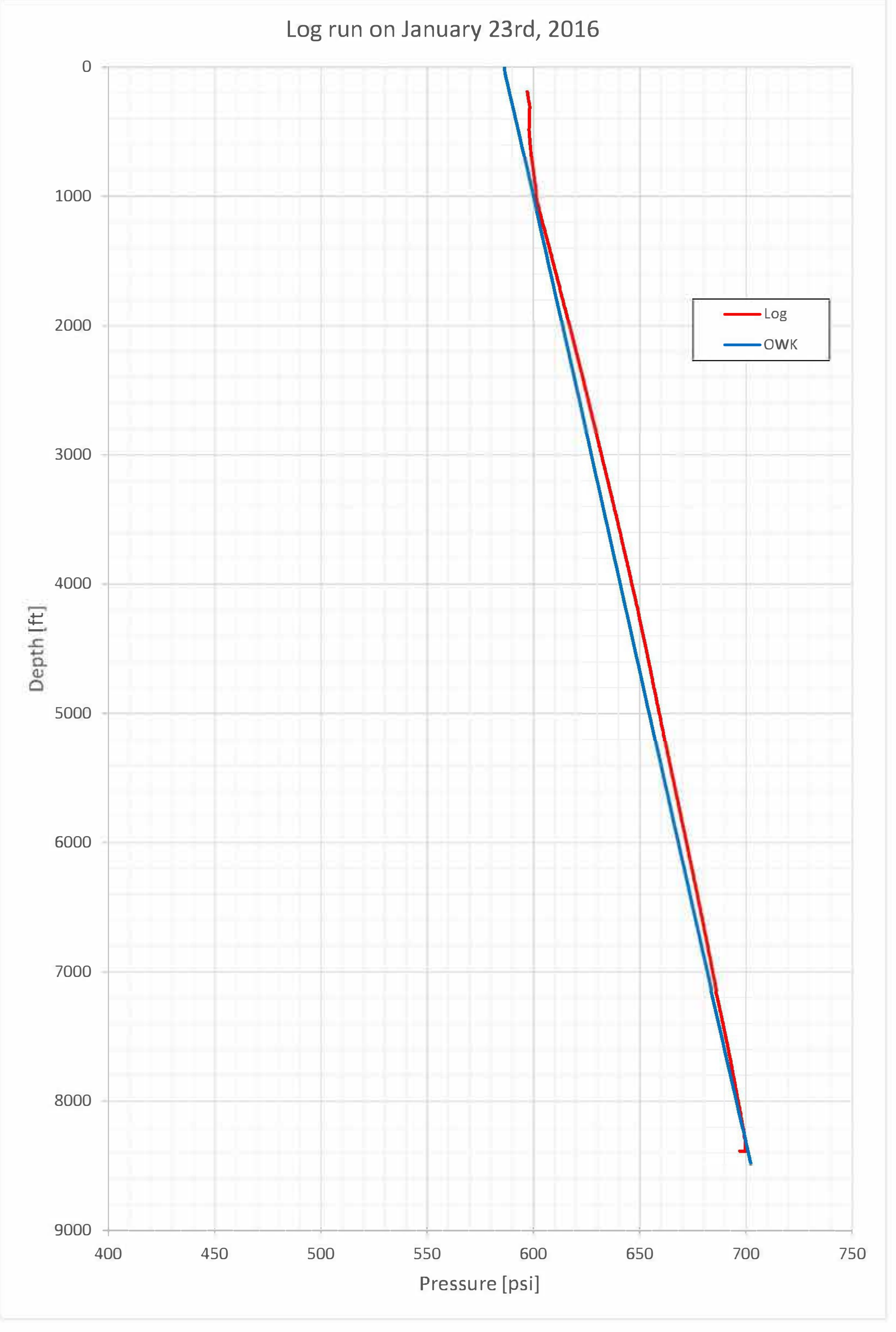


Figure 7.8: Simulated versus pressure from log prior to intersection

Figure 7.9: Simulated versus temperature from log prior to intersection

7.10 Relief well kill simulations for flow in 7" x 2 ⅞" annulus

Three different relief well kill scenarios are modelled all assuming the flow is in the annulus between the 7" casing and the 2 ⅞" tubing:

- Assumed no losses
- Assumed 600 bbls washout downhole
- Assumed fracture gradient of 8.0 ppg downhole

For the scenario with a fracture gradient of 8 ppg, there will be no mud return at surface. When the 9 ppg kill mud is lifted to approximately 1000 ft below the SS25 ground level, the reservoir will fracture.

For the pumping operation, a constant rate of 10 bpm has been assumed pumped into the relief well for simplicity of simulations. This introduce a higher ECD and hence, it will be planned for a reduction in the pump rate as soon as pump pressure is observed on the drillfloor of P39A during the final kill operation. The following plots have however, been based on a constant rate of 10 bpm and the final tubing head pressure is higher than what will be expected during a low rate circulation.

If the centrifugal pumps can be used whilst on losses, these two pumps have showed through tests that they can deliver a total of 34.5 bpm (18 bpm + 16.5 bpm).

The scenarios are also simulated for a case where there is a hole in the tubing to illustrate the different response on the tubing pressure during the pumping operation. Instead of an increasing pressure trend, the tubing pressure would fall as mud would displace the gas inside of the tubing.

The following shows trend plots of various pressures and rates during the kill operation. During the kill these plots can serve as an input to analyzing the operation and evaluate the ongoing operation.

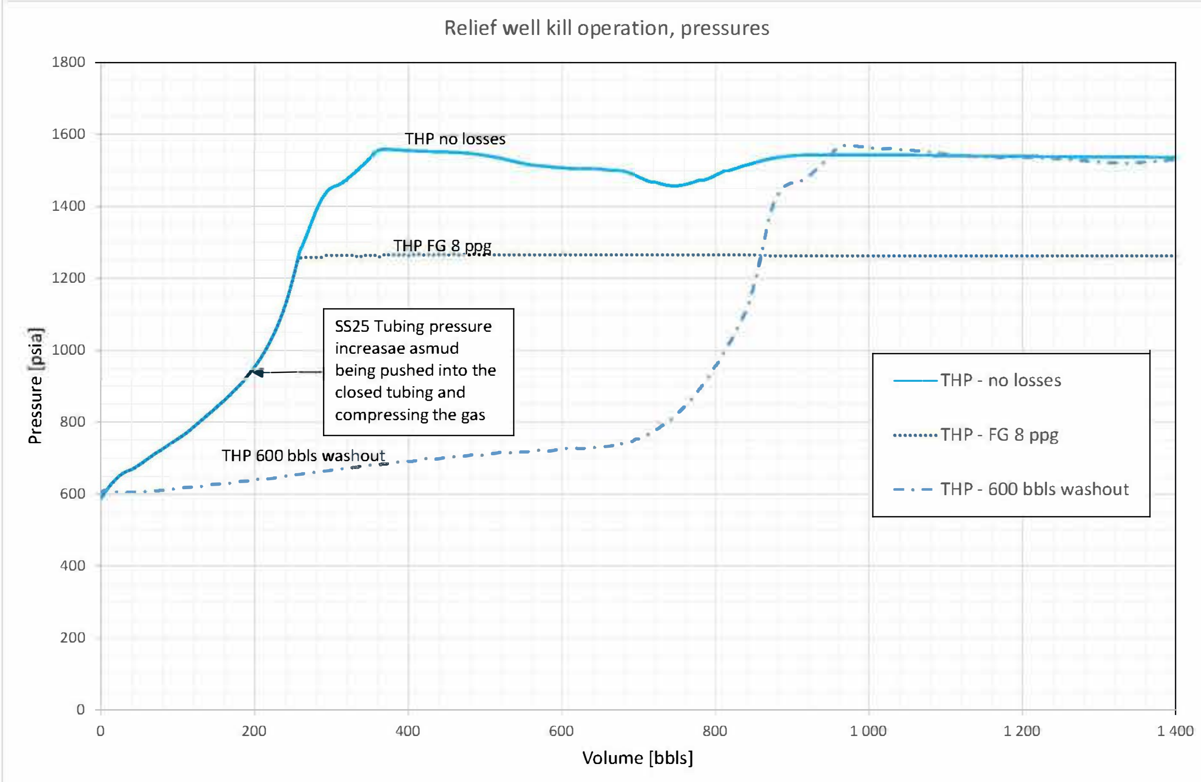


Figure 7.10: Relief well kill scenarios, 2 ⅞" tubing pressures

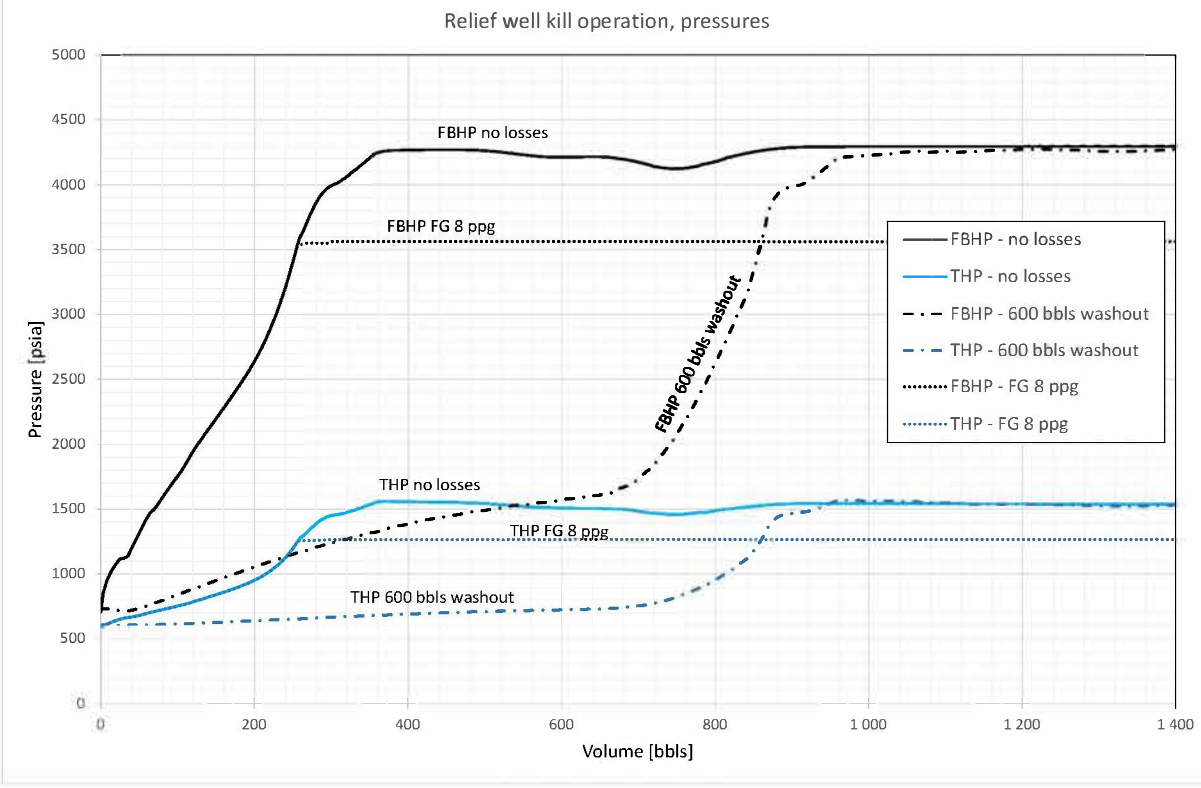


Figure 7.11: Relief well kill scenarios, FBHP and tubing pressures

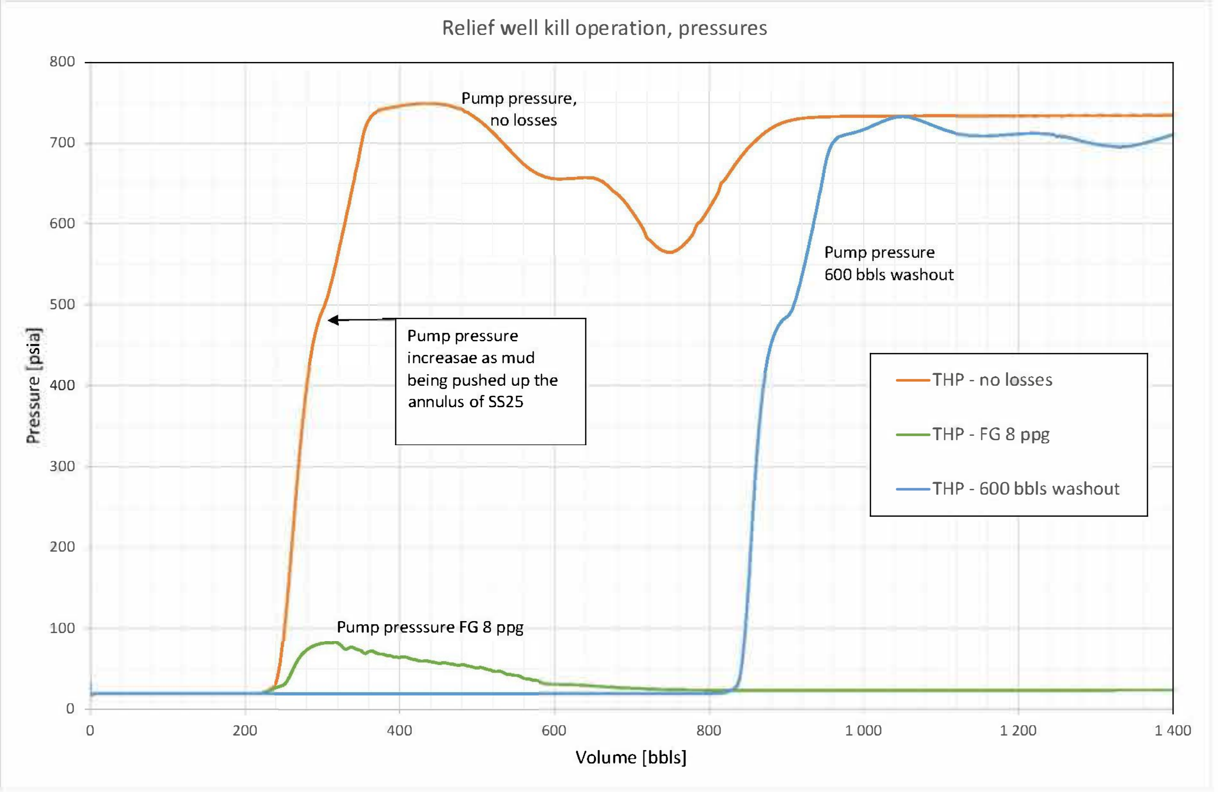


Figure 7.12: Relief well kill scenarios, RW pump pressures

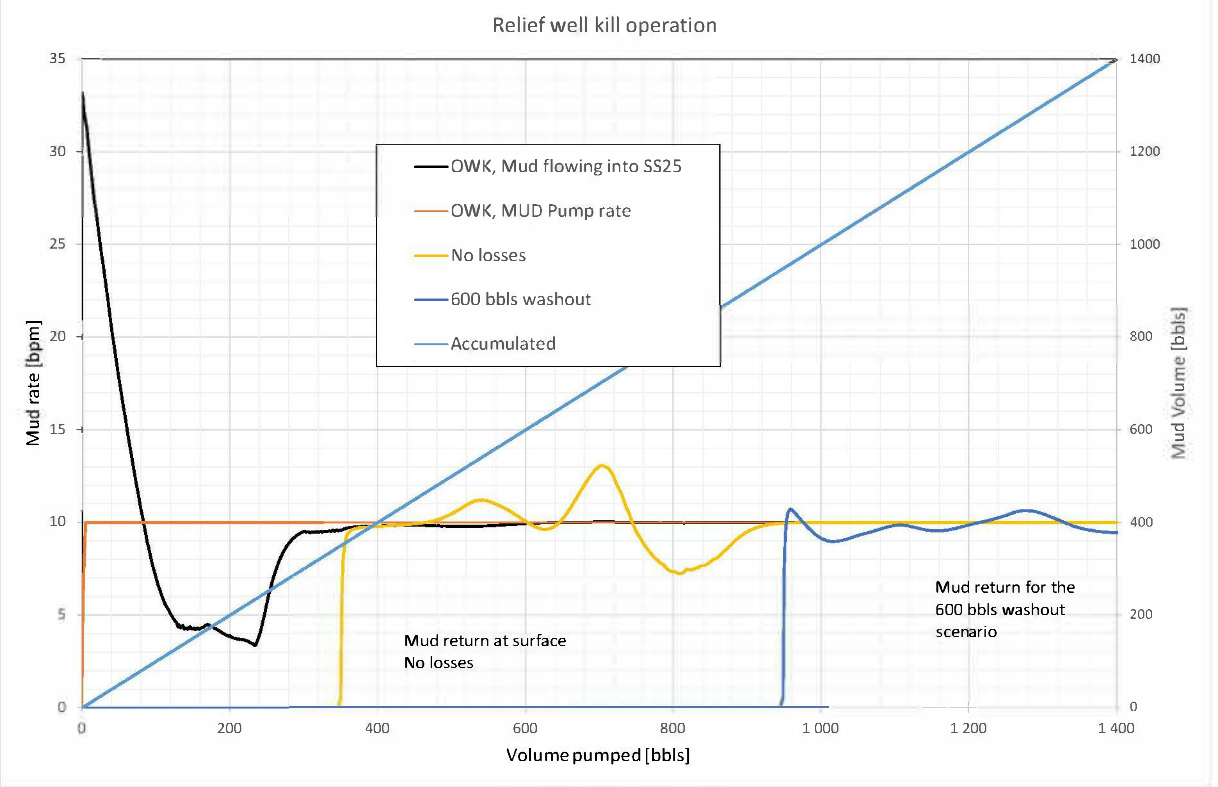


Figure 7.13: Relief well kill scenarios, mud rates and cumulative volume

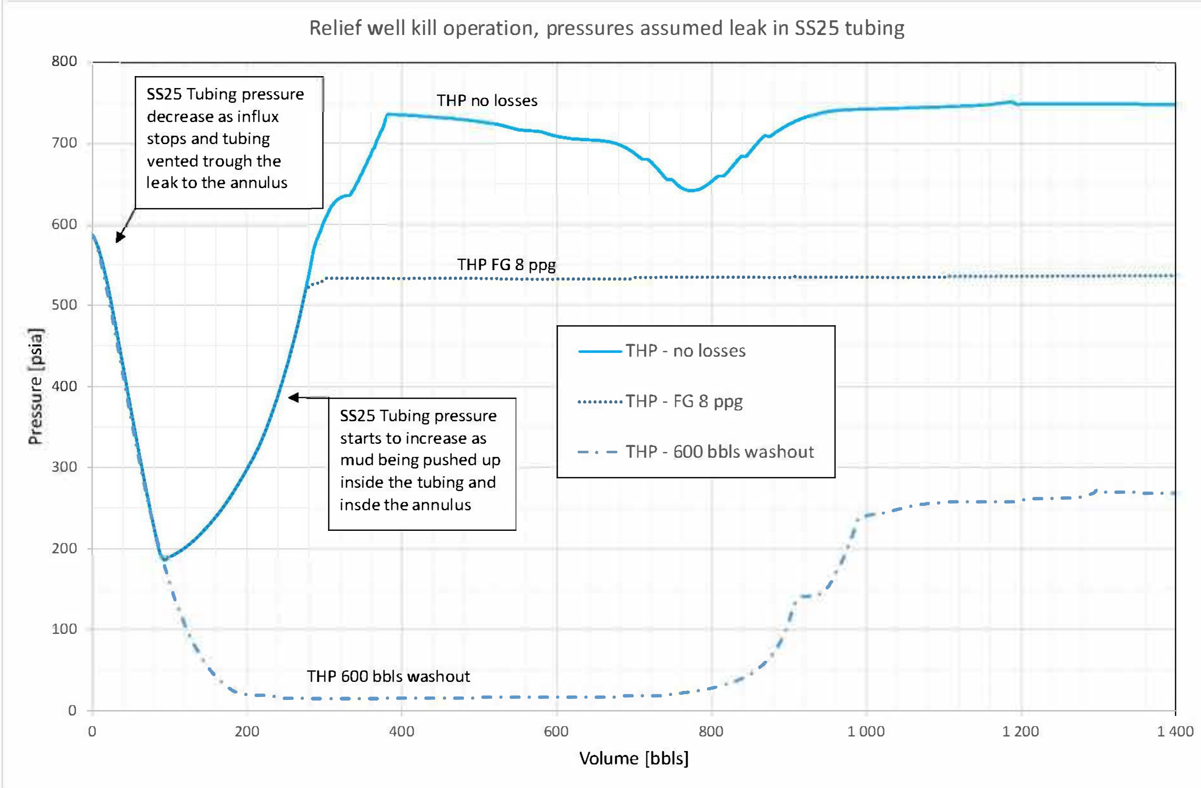


Figure 7.14: Example of relief well kill scenarios assuming hole in tubing

7.11 Relief well kill simulations for flow outside of the 7" casing

A scenario where it was assumed that the flow path was on the outside of the 7" casing, in the annulus between the 10 ⅝" hole and the 7" casing, was also simulated to have a basis for diagnostics during the kill operation. For these simulations, it is being assumed that the centrifugal pumps are being used initially, delivering a pump rate of 34.5 bpm. After 8 mins of pumping, the it is switched to the mud pumps delivering 10 bpm.

As can be observed, the pressure buildup on the tubing has a quite different slope compared to the base case flow scenario between the 7" casing and the 2 ⅞" tubing. This is because the cross sectional area in that annulus is larger than the inner annulus and hence it takes more volume of kill fluid to increase build hydrostatic height.

The following charts show trend plots of key results.

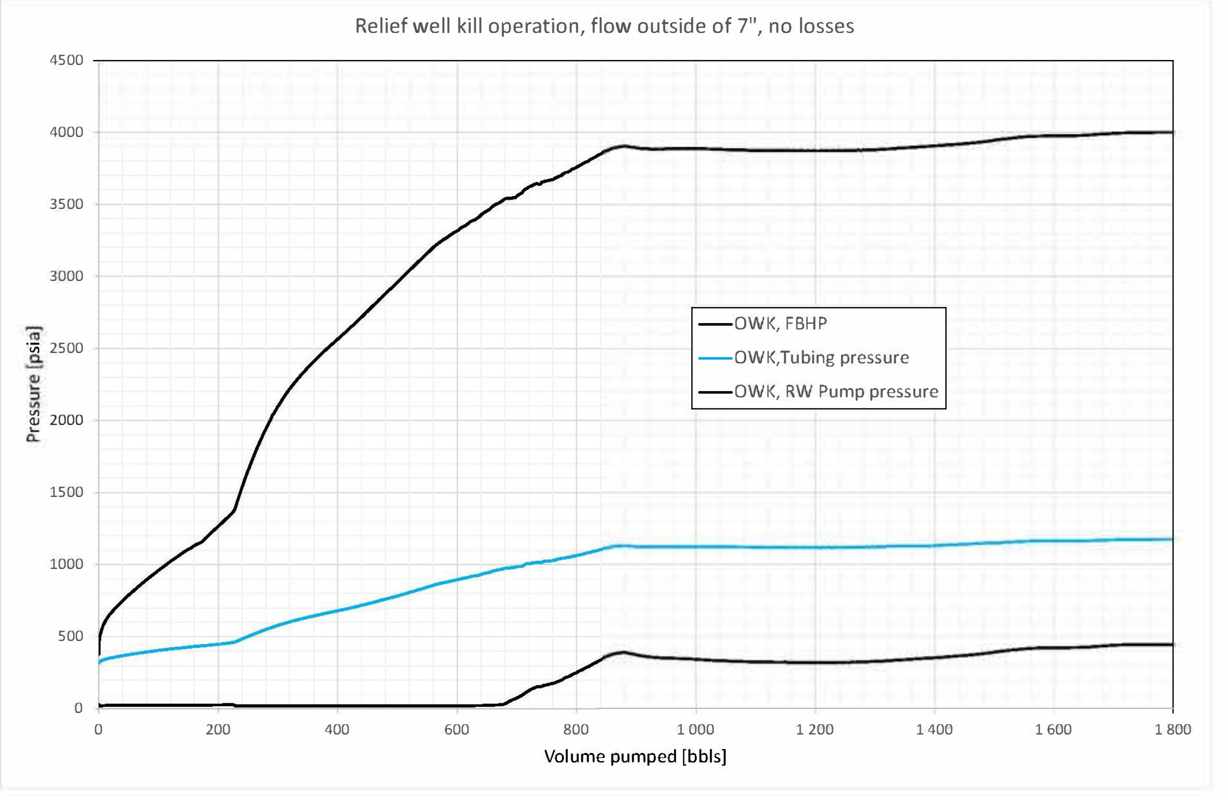


Figure 7.15: Pressures during RW kill assuming flow outside the 7" csg

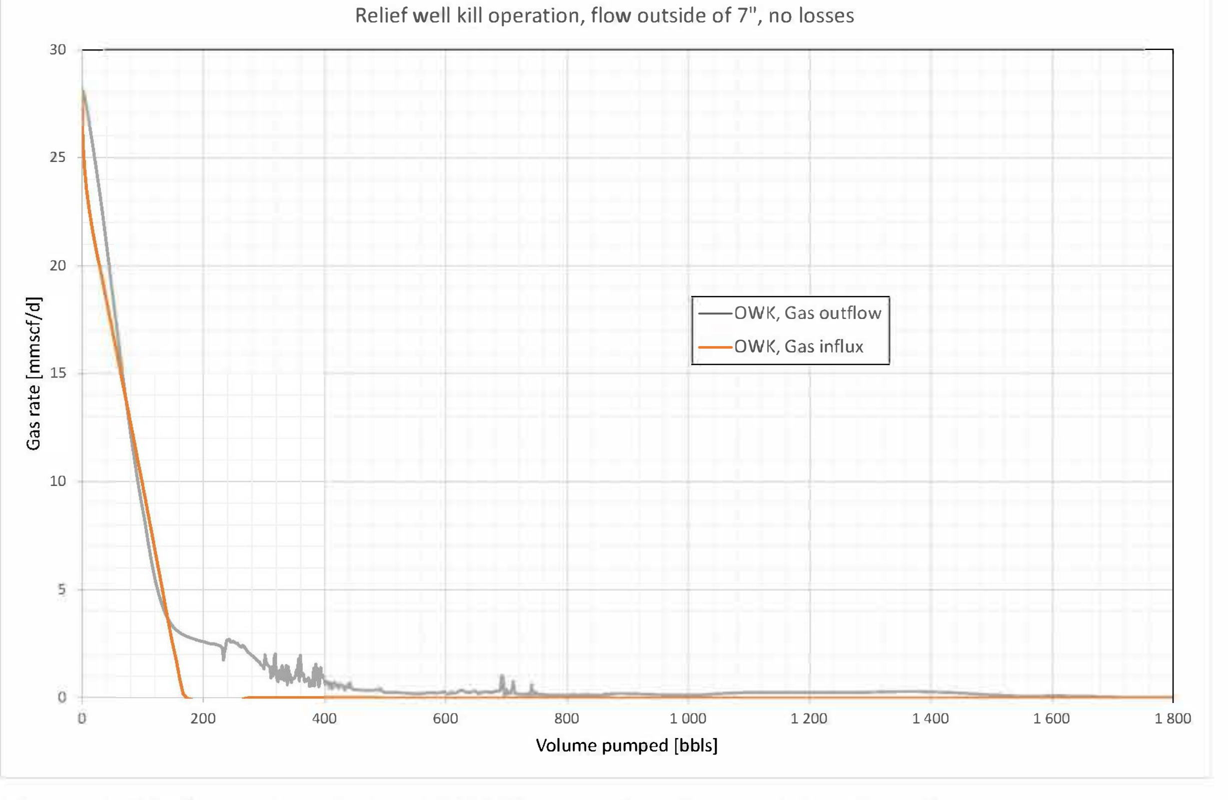


Figure 7.16: Gas rates during RW kill assuming flow outside the 7" csg

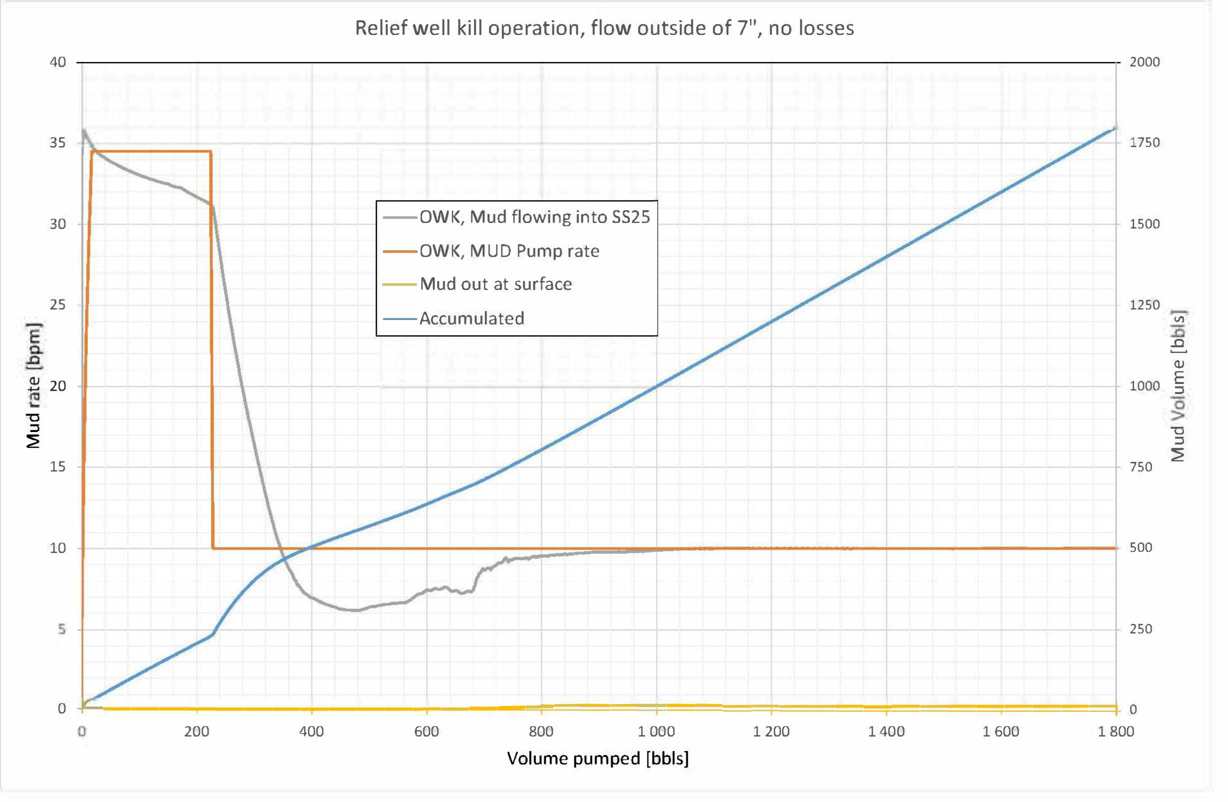


Figure 7.17: Mud rates and volumes during RW kill assuming flow outside the 7" csg

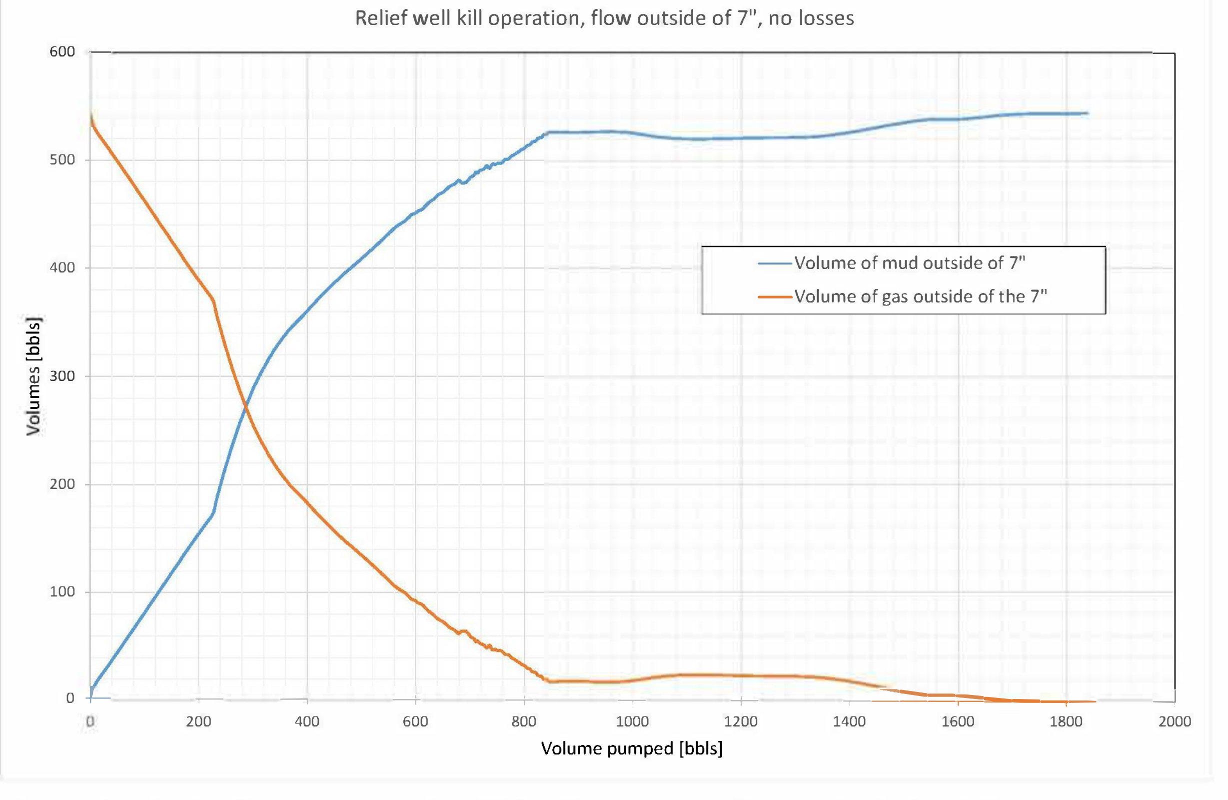


Figure 7.18: Fluid volumes during RW kill assuming flow outside the 7" csg

8. Relief well kill operation on February 11th 2016

8.1 General

The SS25 well was successfully killed on February 11th 2016. The relief well (P39A) was perfectly aligned with SS25 after 29th ranging runs and intersected at the planned depth of 8616 ft MD (8168 ft TVD) referenced the P39A. The incidence angle was 3 degrees.

The mud weight in the relief well was 8.9 ppg (not 9.0 ppg as earlier mentioned) and hence the pressure inside of the relief well was 3800 psi. The flowing bottomhole pressure in SS25 at the time was estimated to be 720 psi.

As documented in this report in the previous chapters, once intersection is being made, significant losses would occur and kill the well in minutes. The operation matched quite well with the predicted operation as already being performed prior to the operation. The operation confirmed the flow path inside of the 7" casing and the 2 ⅞" tubing, and it confirmed a shallow leak in the 7" casing. It further confirmed that close to the surface, mud will flow into fractures and cavities capable of taking large volumes of fluids.

8.2 Chronology of kill operation

Once then intercept was made with SS25 it was planned to keep the annular preventer open and fill P39A using centrifugal pumps due to heavy losses. According to the reported pit volumes including the volume transferred from the silo a total of 510 bbls was pumped down hole, see Figure 8.1. At 09:54:50, the pumps were shut down after the tubing pressure had settled out at 1400 psi.

There were no flow meters on the centrifugal pumps topping up the riser prior to closing the BOP at 08:05, and the only indication of loss rate is the mud tank volumes available from the Pason realtime data. During the kill, 200 bbls were transferred from the silo to the active mud system. There were no actual measurements on the timing of the transfer and therefore the loss rate with time is somewhat uncertain. The tank volumes are documented and available from the Pason real time data, however, the transfer from the silo to the mud system is not documented with rate and time except that a total of 200 bbls were transferred during the kill operation.

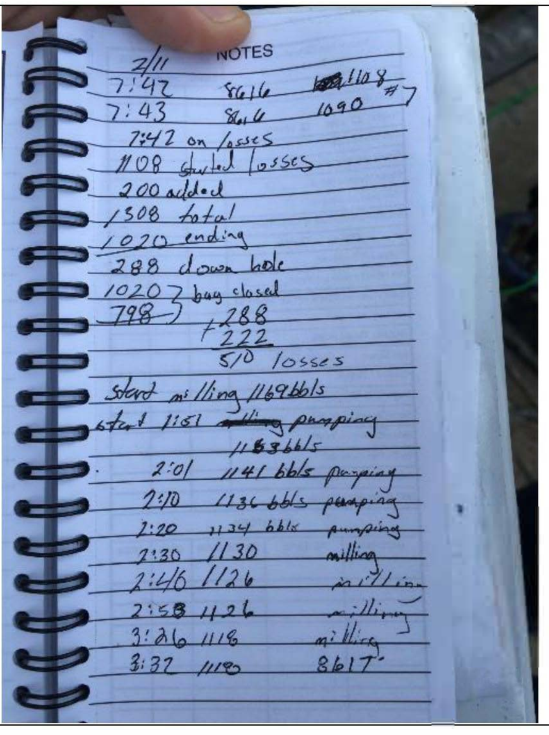
From the BOP was closed and going forward, the mud pump connected to the kill line was used and pump rate is available.

The simulation model will, however determine the flow into the wellbore based on the transient situation and showed a good matched with the total reported cumulative loss of 510 bbls.

Table 8.1: Chronology of relief well kill operation on February 11th 2016

Time	Reported Losses [bbls]	SS25 Tubing Pressure [psia]	Description	Source*
07:42:50	0	602	Intersection being made. Bit depth 8616 ft MD.	Pason
07:43:00		598	Total losses, initial rate of 35 bpm, liquid level in the relief well dropped as the fluid exists at a higher rate than the filling rate	OWK
07:44:00		606	Centrifugal pump is filling the well. Mud is flowing into the well at a peak rate of 30 bpm due to heavy underbalance	Pason, OWK
07:44:30		617	Gas influx from reservoir stopped	OWK
07:45:00		627	Mud pump no 2 still running at 4.23 bpm	Pason
07:45:20		637	Centrifugal pump shut down	Pason
07:49:00		774	Started to pull BHA being pulled back	Pason
07:50:20		847	Centrifugal pump back on and mud pump no 2 turned off	Pason
07:51:10		852	Relief well is filled up and flow returns from well.	Pason, OWK
07:54:00		913	Gas flow at surface stops	OWK
07:57:00		946	Finished pulling back BHA to 8403 ft MD	Pason
08:05:40		1174	Annular preventer was closed. Flow stopped	Pason, OWK
08:10:20		1230	Annular closed. Mud pump 2 started	Pason
09:10		1410	Tubing pressure settles out	Pason, OWK
09:54:50	510	1424	Pump shut down	Pason

* OWK – Olga-Well-Kill simulations, Pason – Relatime data



Time [hrs]	Total Tank Volume [bbls]	Cumulative loss [bbls]
07:42 (Intersection)	1108	0
07:50 – 08:05 (Transfer 200 bbls from silo)	200	
08:05 (Close BOP)	1025	285
09:54 (stop pump)	800	225
Total loss		510

Figure 8.1: Mud log from engineer Ryan Lindsay and real time data from pason

8.3 Simulation results of relief well kill operation

The following show simulation results of the relief well kill operation. As is show, the gas from the reservoir stops almost immediately after intersection has been made. The gas rate at surface ceases 12 minutes later. The pressure build up on the tubing follows the simulated values and confirm the flow path. The pressure on the tubing stabilized after approximately 420 bbls were pumped and even after 510 bbls being pumped there were no visible returns at surface.

The liquid level inside of the tubing after pumping operation stopped would have been 3200 ft measured from surface (see also Table 7.3). The entire volume of the tubing from surface down to the perforations at 8381 ft MD is 48 bbls.

Hence, the remaining volume of gas in the tubing is 18 bbls. This volume of 18 bbls with 1400 psi at surface and 1518 psi at 3200 ft will expand 122 times when vented to atmospheric conditions. Hence, when bleeding off the tubing volume after the SS25 is cemented, a total volume of 687 bbls or 11700 scf of gas will be bled off.

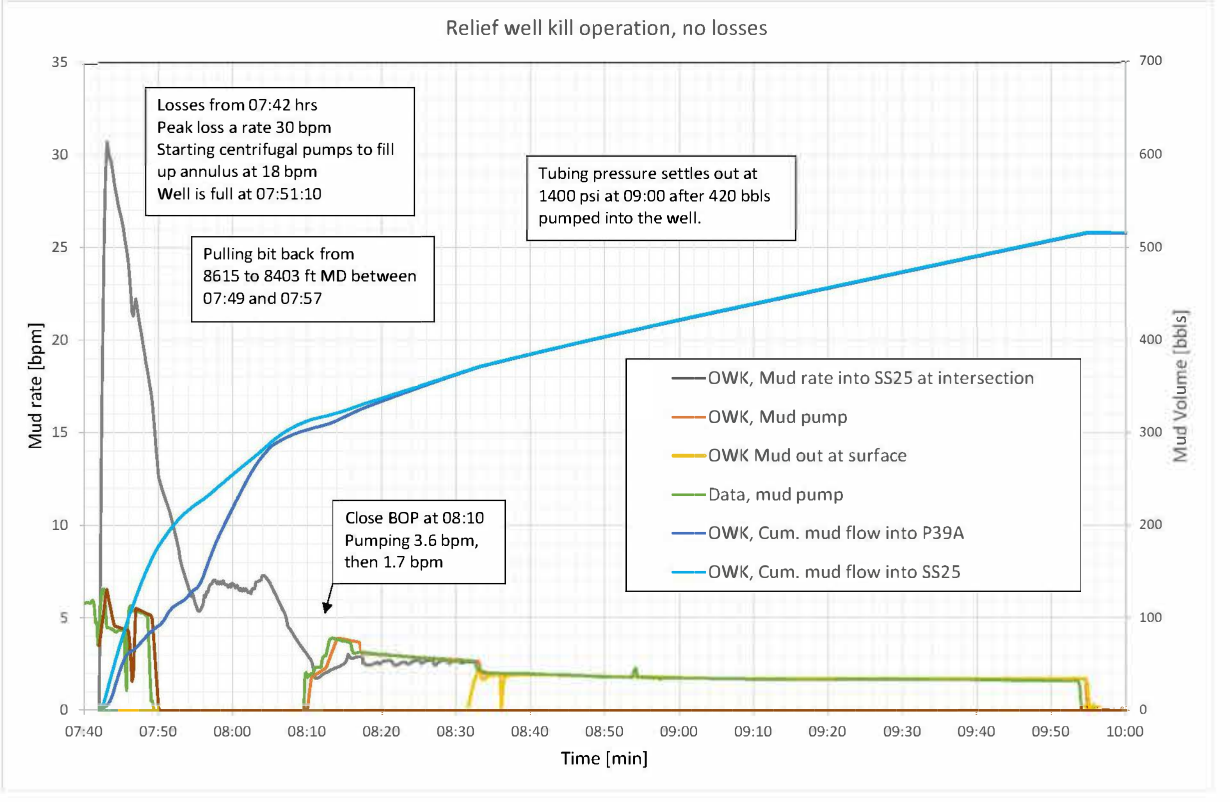


Figure 8.2: Relief well kill operation – mud flow and volumes

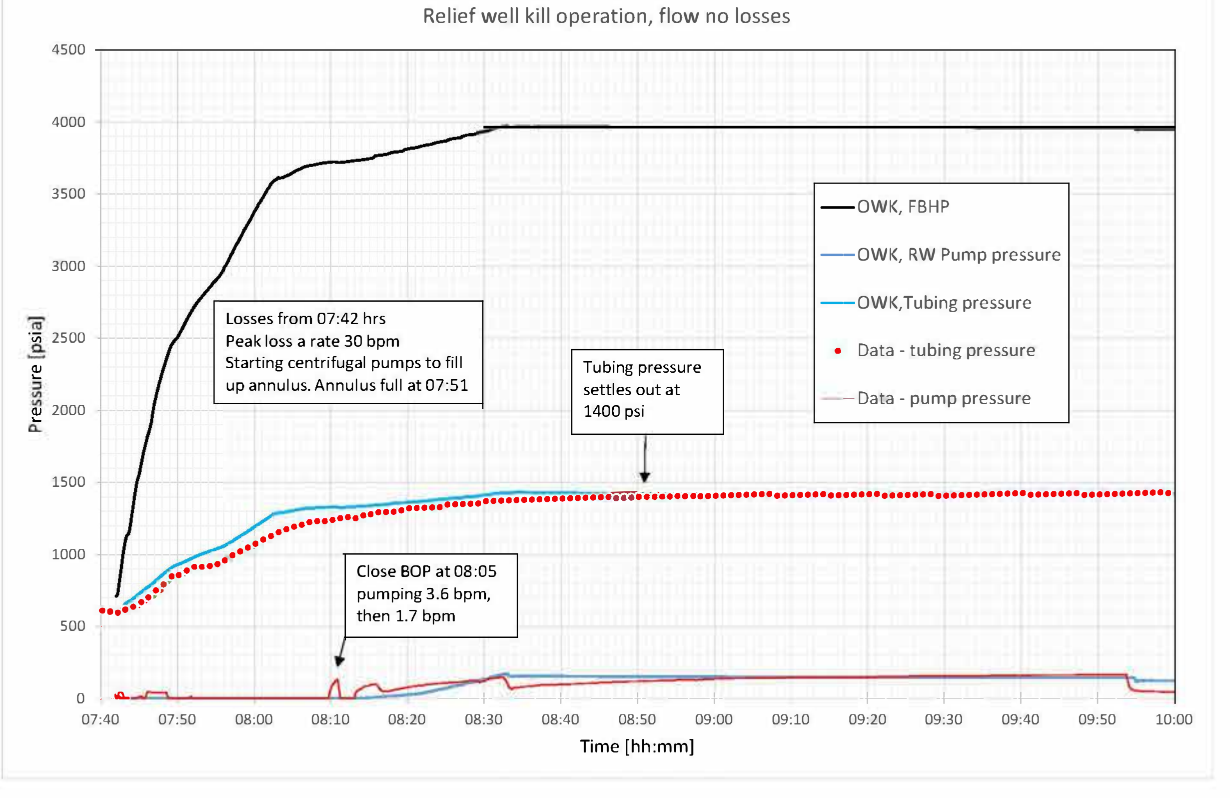


Figure 8.3: Relief well kill operation – pressures

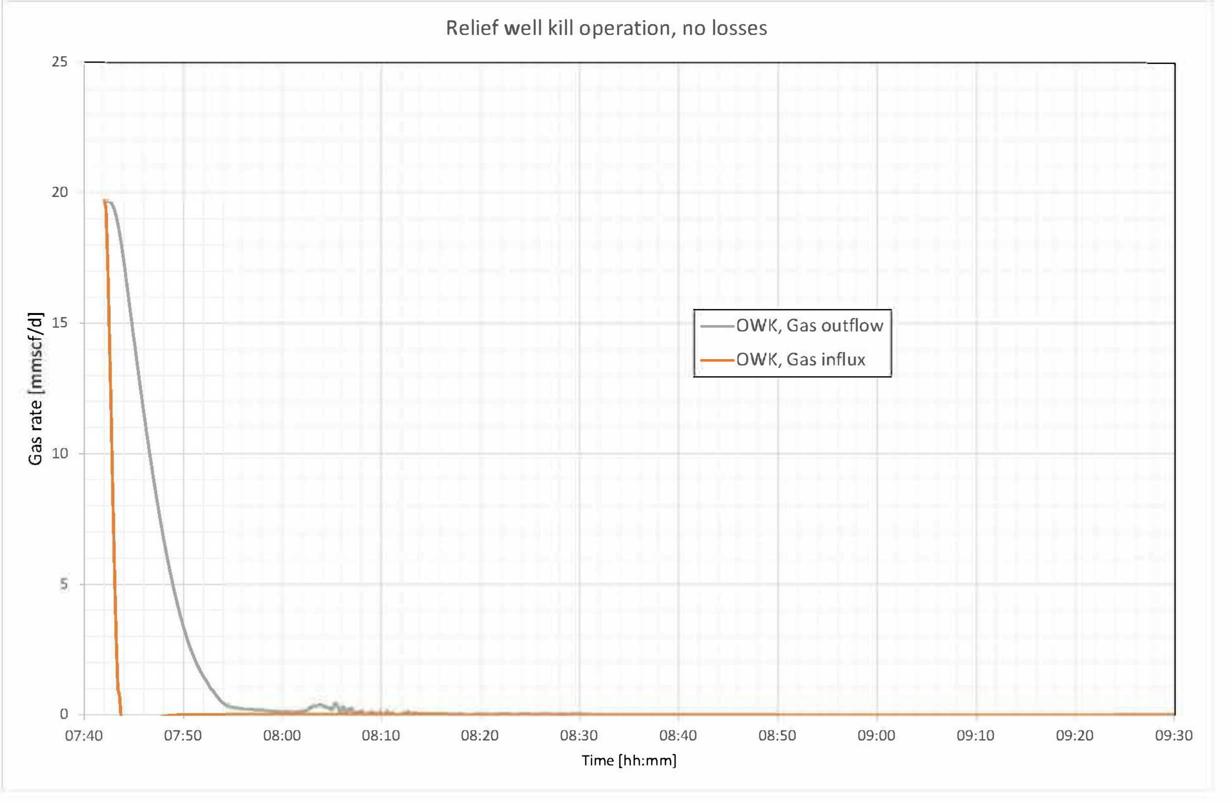


Figure 8.4: Relief well kill operation – gas flow rates

A. Boots & Coots Daily Operations Report Summary

The flowing shows a chronicle of the Boots & Coots Daily Operations

Date:	25-Oct-2015	**Well Name and Number:**	Standard Senson 25	Report #	1
Customer Name:	Southern Califonia Gas Company	**County:**	Los Angeles		
Customer Billing Address:	12801 Tampa Ave., SC 9328	**State:**	California		
	Northridge, CA, 91326	**Country:**	USA		
AFE #:		**Well Location:**	Aliso Canyon Storage Facility		
Customer Representative:		**Well Type:**	Gs		
Report Generated By:	Danny Walzel	**Job Type:**	Well Control		
Lease - Well #:	Standard Senson 25	**Rig No:**	N/A		

Hour	Hour	Activity on Site
8:30	9:30	Boots & Coots personel travel to Bush Intercontinental Airport Houston, Texas.
9:30	11:45	Check in, board plane.
11:45	13:45	Fly from Houston, Texas to Los Angeles, CA.
13:45	13:15	Get rental car.
13:15	14:00	Drive from LAX to Aliso Canyon Storage Facility.
14:00	18:30	Met with Southern California Gas Company representatives. Traveled to Standard Senson 25 wellsite. Performed site
		assessment. Observed gas broaches to surface through several fissures on well pad. Discussed operations prior to broaching
		with client representatives. Was informed client attempted to pump down tubing and could not. Attempted to lube and bleed
		the 2-3/8" x 7" annulus. Pressure increased to 3,200 psi when broaches occurred. Operations were discontinued.
		Began sourcing slick line unit, frac tanks for kill fluid, dual pump truck, and additional pump iron.
18:30	19:00	Traveled to hotel.

Date:	26-Oct-2015	**Well Name and Number:**	Standard Senson 25	Report #	2

Well Summary
Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
6:30	7:00	Traveled from hotel to Aliso Canyon Storage Facility.
7:00	8:00	Attended morning meeting. Discussed fabricating A-Frame for slick line operations, sourcing intrinsically safe slick line unit,
		wellhead integrity, greasing and testing casing valves, and where to spot equipment on location.
8:00	8:30	Traveled to Standard Senson 25 wellsite. Performed site assessment. Gas activity was observed to be unchanged.
8:30	10:15	Observed 7" x 11-3/4" annulus pressure to be 428 psi. Dug out around wellhead to expose casing valve. Closed ball valve.
		Removed gauge and bushing from ball valve.
10:15	12:30	Operations were shut down for safety meeting and operational update.
12:30	14:00	Installed ball valve. Made up 602 iron from wellhead to test separator.
14:00	15:30	Checked wellhead pressures on 25A and 25B. 25A wellhead pressure 0 psi. 25B wellhead pressure 40 psi.
15:30	16:45	Began flowing well 25 7" x 11" annulus through test separator on 16/64" choke. 2-7/8" - 680 psi. 2-7/8" x 7" - 419 psi.
		7" x 11-3/4" - 413 psi.
16:45	17:00	Opened choke to 23/64" choke. 2-7/8" - 446 psi, 2-7/8" x 7" - 416 psi, 7" x 11-3/4" - 404 psi. Gas rate 8 Mscf/day. Temp - 48F.
		Shut down. Secured well.
17:00	18:30	Attended end of the day meeting. A slick line unit has been sourced. A total of 1,000 bbls of 10.0 ppg KCl was delivered to
		location. Sourced Halliburton HT400. Customer requested B&C HSE specialist. Mike Baggett will travel to location tomorrow.
		Welder sourced materials and will begin fabricating A-Frame.
18:30	19:00	Traveled to hotel.

Date:	27-Oct-2015	**Well Name and Number:**	Standard Senson 25	Report #	3

Well Summary
Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
6:45	7:15	Traveled from hotel to location. Inspected slick line unit.
7:15	8:30	Performed site assessment. Discussed the day's operations with SCGC representatives. 7" x 11-3/4" - 325 psi. 2-7/8" x 7" -
		307 psi. 2-7/8" - 34 psi.
8:30	10:15	Rigged up to flow 2-7/8" x 7" annulus to test separator.
10:15	11:15	Spot slick line unit and generator.
11:15	13:30	Continued isolating kill lines and with draw lines to well 25.
13:30	14:45	Opened orbitz valve on with draw line. 2-7/8" x 7" annulus pressure decreased from 260 psi to 15 psi. Monitored well.
14:45	15:00	7" x 11-3/4" - 308 psi. 2-7/8" x 7" - 16 psi. 2-7/8" - 78 psi. Began bleeding 7" x 11-3/4" annulus through test separator on 11/64
		choke. Choke pressure 275 psi. Gas rate 3 Mcf/day.
15:00	15:30	Opened choke to 23/64. Choke pressure 300 psi. 2-7/8" x 7" - 21 psi. 2-7/8" 75 psi. Closed choke. 7" x 11-3/4" - 310 psi.
		2-7/8" x 7" - 25 psi. 2-7/8" - 78 psi. Mike Baggett arrived on location. Met with SCGC safety representatives.
15:30	14:00	Secured well.
14:00	17:30	Continued rigging up slick line unit. Met with welder and slick line crew to discuss required modifications to A-Frame.
		Rigged up Halliburton HT400 pump truck.
17:30	18:00	Departed location. Traveled to hotel.

Date:	28-Oct-2015	**Well Name and Number:**	Standard Senson 25	Report #	4

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
6:45	7:15	Traveled from hotel to location.
7:15	7:45	Attended morning safety/operations meeting.
7:45	8:00	Performed site assessment. Gas flow from fissures on well pad appear to have decreased.
8:00	9:30	Checked pressures on 25 well. 7" x 11-3/4" - 325 psi. 2-7/8" x 7" - 128 psi. 2-7/8" - 170 psi. Bled tubing pressure to 86 psi.
9:30	11:30	Closed all casing valves. Installed A-Frame on well. Continued rigging up slick line. (10:00) Checked pressure on
		2-7/8" x 7" annulus - 134 psi. Bled to 124 psi.
11:30	12:15	Made up 1-5/8" sample bailer. Stabbed lubricator. Opened up well. 2-7/8" x 7" - 109 psi. 2-7/8" - 87 psi. RIH with sample bailer
		Sat down hard at 467 ft. Pulled out of the hole. Inspected sample bailer. Observed polymer on tool. Tool temperature 47 deg F.
		Fluid level - 300 ft.
12:15	12:45	Lunch.
12:45	14:15	Shot fluid levels on 7" x 11-3/4" and 2-7/8" x 7" annulus. 7" x 11-3/4" - 43 ft. 2-7/8" x 7" - 164 ft.
14:15	15:30	Lined up Halliburton to pump 8.7 ppg Flozane down tubing.
15:30	16:15	Filled kill line with 9.5 bbls. Pumped 3.1 bbls. Pump pressure increased to 350 psi. Monitored 5 minutes. Pressure increased
		to 377 psi. Pumped 0.2 bbls. Tubing pressure 500 psi. Monitored for 5 minutes. Tubing pressure increased to 525 psi.
		Pumped 0.5 bbls. Tubing pressure increased to 776 psi. Monitored for 5 minutes. Tubing pressure increased to 801 psi.
		Pumped 0.1 bbls. Tubing pressure 998 psi. Monitored for 5 minutes. Tubing pressure increased to 1,027 psi. Pumped 0.1 bbls.
		Tubing pressure 1,220 psi. Monitored for 5 minutes. Tubing pressure increased to 1,337 psi. Pumped 0.1 bbls. Tubing pressure
		1,480 psi. Monitored for 5 minutes. Tubing pressure 1,603 psi.
16:15	17:00	Tubing pressure 1,824 psi. Bled to 1,790 psi. Continued monitoring well. (16:50) Tubing pressure 2,400 psi. Closed tubing
		head valve. Tubing pressure remained constant. Pressure on pump truck increased to 2,595 psi. Suspect communication with
		field injection lines. Made up 1-5/8" sample bailer.
17:00	17:30	Ran in hole with sample bailer. Tagged hard at 467 ft. Pulled out of the hole. Secured well.
17:30	18:00	Attended end of the day meeting.
18:00	18:30	Travel to hotel.

Date: 29-Oct-2015	Well Name and Number:	Standard Senson 25	Report #	5

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site. Surface casing pressure fluctuates between 505 psi and 770 psi.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
6:30	7:00	Traveled from hotel to location.
7:00	7:30	Attended morning safety/operations meeting.
7:30	8:15	Performed site assessment. Observed ice on fissures around cellar. Fissures appeared to have made fluid overnight. Checked
		pressures on SS 25. 2-7/8" - 429 psi. 2-7/8" x 7" - 353 psi. 7" x 11-3/4" - 505 psi.
8:15	8:30	7" x 11-3/4" pressure - 515 psi. Flowed annulus for fifteen minutes. Shut in. Casing pressure 509 psi.
8:30	9:30	Moved in and rigged up crane. Laid down lubricator. Removed A-Frame from well. 2-7/8"- 360 psi. 2-7/8" x 7" - 420 psi.
		7" x 11-3/4" - 560 psi. Checked pressures on 25B. 2-7/8" - 2,450 psi. 2-7/8" x 7" - 2,450 psi. 7" x 11-3/4" - 44 psi.
9:30	10:30	Western wireline added sinker bar and lubricator.
10:30	10:45	Shot fluid levels on SS 25.
10:45	11:00	Bled 2-7/8" x 7" annulus f/ 456 psi t/ 440 psi
11:00	12:00	Installed 2-9/16" 5M upper master valve. 2-7/8" - 375 psi. 2-7/8" x 7" - 462 psi. 7" x 11-3/4" - 591 psi.
12:00	12:30	Held PJSM to discuss slick line operations.
12:30	13:15	Made up 1.625" sample bailer. Stabbed lubricator. RIH. Sat down at 37 ft. POOH. Tool temperature 59 deg F. 2-7/8" - 54 psi.
13:15	13:45	Stabbed lubricator. RIH with 1.625" sample bailer. Sat down at 37 ft. POOH. Tool temperature - 19 deg F. Observed ice
		in sample bailer. Rigged down slick line.
13:45	14:15	Met with HALCO representatives to discuss coiled tubing operations. A coiled tubing unit is being mobilized from Houma, LA.
14:15	15:30	Blew down with draw and kill lines from 450 psi to 50 psi. Discussed removing lines to isolate SS 25 from facility lines.
15:30	16:00	Attended end of the day meeting. Coiled tubing unit will take 2 days to arrive at location. Will remove lateral lines from SS 25.
		Will move Halliburton pump truck closer to SS 25. SCGC will continue running diagnostics on nearby wells.
16:00	18:00	Continued monitoring pressures. (16:30) 2-7/8" - 51 psi. 7" - 685 psi. 11-3/4" 731 psi. (17:00) 2-7/8" - 55 psi. 7" - 634 psi.
		11-3/4" - 697 psi. (17:30) 2-7/8" - Shut in. 7" - 631 psi. 11-3/4" - 770 psi.
18:00	18:30	Traveled to hotel.

Date:	30-Oct-2015	Well Name and Number:	Standard Senson 25	Report #	6

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site. Surface casing pressure fluctuated between 750 psi and 830 psi.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
6:30	7:00	Traveled from hotel to location.
7:00	7:30	Attended morning safety/operations meeting.
7:30	8:15	Performed site assessment. Gas flow from fissures has decreased. Checked pressures on 25 well. 2-7/8" - Shut in. 7" - 614 psi. 11-3/4" - 823 psi.
8:15	11:45	Isolated wells 25A and 25B from injection and withdraw lines. Blew down lines from 250 psi to 0 psi. Met with Weatherford representative to discuss equipment requirements for coiled tubing operations. (10:50) Well 25 11-3/4" casing pressure decreased from 830 psi to 750 psi.
11:45	12:30	Removed tubing kill lateral from well 25.
12:30	13:00	Lunch
13:00	15:00	Removed kill and withdraw laterals from 7" casing spool and with draw line from tubing head. Removed 3-1/8" 5M manumatic valve from 7" casing head. Removed 2-1/6" 5M manumatic from tubing head. Installed 2-1/16" 5M valve on same. Installed 3-1/8" 5M 2" LP companion flanges with 2" tapped bull plugs with needles valve on 7" annulus casing valves. Installed 2-1/16" 5M 2" LP companion flanges with 2" tapped bull plugs with needle valves on tubing head casing valves. Installed tapped flanges w/ 2" LP needle valves on kill and with draw lines.
15:00	16:00	Nippled up 2-9/16" 5M x 4-1/16" 10M DSA, 4-1/16" 10M Gate Valve, and 4-1/16 10M x 4-1/16" 15M DSA on upper master valve. Installed Rotemount transducers on well 25 7" casing outlet valve and 11-3/4" casing outlet valve. 7" - 585 psi. 11-3/4" - 770 psi.
16:00	17:30	Well 25A: Bled 8-5/8" casing from 920 psi to 700 psi. Shut in. Well 25: 7" - 584 psi. 11-3/4" - 771 psi.
17:30	18:00	Traveled to hotel.

Date:	31-Oct-2015	Well Name and Number:	Standard Senson 25	Report #	7

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
6:30	7:15	Traveled from hotel to location.
7:15	7:30	Attended morning safety/operations meeting. Performed site assessment. Well 25: Tbg - Shut in. 7" - 574 psi. 11-3/4" - 716 psi.
7:30	9:30	Checked surface casing pressure on 25A - 52 psi. Removed slick line equipment from Pad 25. Spotted hydraulic choke manifold.
9:30	11:00	Removed companion flanges from tubing head outlet valves. Installed 2-1/16" x 1502 thread half adapter flanges on same. Removed companion flange from 7" casing outlet valve. Installed 3-1/8" 5M x 1502 thread half adapter flange. Installed 1" plug valve.
11:00	12:30	Lined up on 25A tubing. 25A tubing pressure 2,600 psi. 8-5/8" - 940 psi. Well 25: 7" - 576 psi. 11-3/4" - 737 psi. Pumped 30 bbls 8.7 ppg polymer pill. Displaced with 152 bbls 8.5 ppg KCl. Shut down. Tubing pressure 550 psi. 8-5/8" casing 889 psi. Well 25: 7" - 578 psi. 11-3/4" - 749 psi. Well 25A: Bled 8-5/8" casing from 889 psi to 770 psi. Shut in.
12:30	13:00	Lunch.
13:00	13:30	Removed gauges and 3-1/8" 5M companion flange from 7" casing outlet valve. Installed 3-1/8" 5M x 1502 thread half adapter flange. Installed 1" plug valve and gauges.
13:30	14:00	Well 25A: Bled 8-5/8" casing pressure from 770 psi to 0 psi.
14:00	15:45	Filled 25A 2-7/8" x 8-5/8" annulus with 205 bbl 8.5 KCl. Left 50 psi on annulus and 600 psi on 2-7/8" tubing.
15:45	16:30	Met with welder to discuss fabricating valve extension handle to operate wellhead ball valves. Well 25: 2-7/8" - Shut in. 2-7/8" x 7" - 584 psi. 7" x 11-3/4" - 727 psi.
16:30	17:00	Traveled to hotel.

Date:	1-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	8

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
6:30	7:15	Traveled from hotel to location.
7:15	7:30	Attended morning safety/operations meeting.
7:30	7:45	Performed site assessment. Well 25: 2-7/8" - Shut in. 7" - 676 psi. 11-3/4" - 690 psi.
7:45	8:30	Met with Halliburton Coiled Tubing Supervisor. Discussed well situation and where to spot coiled tubing equipment.
8:30	11:15	Rigged up on 25B. Tubing pressure - 2,500 psi. 8-5/8" - 2,440 psi. Pumped 30 bbls 8.7 ppg polymer pill down tubing. Pumped 387 bbls 8.5 ppg KCl. Shut down. Tubing pressure 0 psi. 8-5/8" - 0 psi.
11:15	11:45	Well 25: Installed valve extension handle on outer well head casing valve.
11:45	12:30	Lunch.
12:30	12:45	Well 25B: Tubing Pressure - 0 psi. 8-5/8" - 0 psi. 13-3/8" - 42 psi. Well 25 A: 2-7/8" - 1,000 psi. 8-5/8" - 140 psi. 13-3/8" - 0 psi. Well 25: 2-7/8" - Shut in. 7" - 694 psi. 11-3/4" - 679 psi.
12:45	14:30	Prepared location for coiled tubing equipment. Met with Halliburton and Onyx. Discussed rig up requirements for well 25. Onyx is going to fabricate 602 x 1502 cross overs for return lines. Rigged down and moved out 40T crane.
14:30	16:00	Moved in and rigged up 110T crane. Coiled tubing reel arrived at Aliso Canyon Storage Facility.
16:00	16:30	Attended end of the day meeting.
16:30	17:00	Traveled to hotel.

Date: 2-Nov-2015		Well Name and Number: Standard Senson 25	Report # 9
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
6:30	7:15	Traveled from hotel to location.	
7:15	7:45	Morning safety/operations meeting. Performed site assessment. Well 25: 2-7/8" - Shut in. 7" - 686 psi. 11-3/4" - 663 psi.	
7:45	10:45	Rigged up return line from 7" annulus to choke manifold. Installed panic line.	
10:45	12:00	Offloaded and spotted 1.5" coiled tubing reel.	
12:00	13:15	Offloaded cab and injector. Well 25: 2-7/8" - Shut in. 7" - 682 psi. 11-3/4" - 638 psi.	
13:15	14:30	Offloaded coiled tubing power pack, hydraulic tank, and stripper .	
14:30	15:45	Offloaded coiled tubing BOP stack, goose neck, generator, and two hose baskets.	
15:45	17:00	(16:10) Well 25: 11-3/4" pressure decreased to 284 psi. 7" decreased to 659 psi. Offloaded tool house and hose baskets.	
		Moved man lift to pad 25.	
17:00	17:30	Attended end of the day meeting.	
17:30	18:00	Traveled to hotel.	

Date: 3-Nov-2015		Well Name and Number: Standard Senson 25	Report # 10
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. LEL levels at well 25 cellar were 100%. LEL levels 25 ft from well 25 were 14%.	
		Well 25: 2-7/8" shut in. 7" - 626 psi. 11-3/4" - 599 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	7:15	Took LEL readings around well 25. LEL levels at cellar were 100%. LEL levels 25 ft from well 25 were 0 - 6%.	
7:15	12:00	Spotted coiled tubing control cab, reel, and generator. Began rigging up. Installed line from tubing head to choke line.	
		Spotted HT400 pump truck.	
12:00	12:30	Lunch.	
12:30	17:00	Continued rigging up coiled tubing unit. (13:00) Well 25: 2-7/8" - Shut in. 7" - 645 psi. 11-3/4" - 623 psi. Spotted MI/Swaco	
		choke panel. Rigged up and function tested. Function tested BOP's. Nippled up 4-1/16" 10M riser. Nippled up BOP's.	
		Installed kill lines. Dressed coiled tubing and installed connector. Delivered 490 bbls of 10.8 ppg CaCl2 to location.	
17:00	17:30	Attended end of the day meeting. Will pull test and pressure test in the morning.	
17:30	18:00	Traveled to hotel.	

Date: 4-Nov-2015		Well Name and Number: Standard Senson 25	Report # 11
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 44%. LEL 25 ft from well 25 0 - 5%. 2-7/8" - Shut in. 7" - 512 psi.	
		11-3/4" - 555 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	8:15	Pull tested coil tubing with 15k lbs.	
8:15	9:00	Filled coil tubing with 19.5 bbls 10.8 ppg CaCl2.	
9:00	13:00	Held PJSM to discuss pressure testing operations. Tested reel to 300/8,000 psi for 10 minutes each test. Test good.	
		Filled stack. Trouble shoot leak in kill line. Tested choke line to 300/4,000 psi 5 minutes/test. Change out two lo-torq valves.	
		Continued pressure testing choke line. Observed leak from adapter flange on choke manifold. Tightened flange. Tested both	
		BSR's to 300 psi low/4,000 psi high. Tests good.	
13:00	14:00	Made up wash assembly BHA.	
14:00	17:30	Stabbed injector. Tested BOP's to 300 psi low and 4,000 psi high. Tested choke manifold valves to 300 psi low and 4,000 psi	
		high. Trouble shoot leak in choke manifold. Secured well for the night. Well 25: Tbg - Shut in. 7" - 523 psi. 11-3/4" - 488 psi.	
17:30	18:00	Attended end of the day meeting.	
18:00	18:15	Traveled to hotel.	

Date: 5-Nov-2015		Well Name and Number: Standard Senson 25	Report # 12
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 25%. LEL 25 ft from well 25 0 - 6%. 2-7/8" - Shut in. 7" - 551 psi.	
		11-3/4" - 467 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	7:30	Discussed yesterday's pressure testing. Will continue trouble shooting choke manifold and retest coil tubing BOP's	
7:30	8:00	Greased valve #2 on choke manifold.	
8:00	11:15	Pressure tested choke manifold valves to 300 psi low and 4,000 psi high. Valve #2 did not test.	
11:15	13:30	Pressure tested lower BSR's to 300 psi low and 4,000 psi high. Changed out valve #2.	
13:30	15:00	Shell tested choke manifold to 300 psi low and 4,000 psi high. Test good. Tested valve #2 to 300 psi low and 4,000 psi high.	
		Test good. 11-3/4" - 515 psi.	
15:00	18:00	Made up wash assembly BHA. Stabbed injector. Tested lower and upper pipe rams to 300 psi low and 4,000 psi high. Tests	
		good. Tested stripper to 300 psi low and 4,000 psi high. Test good. Removed injector and stood back. Secured well.	
18:00	18:30	Traveled to hotel.	

Date: 6-Nov-2015	Well Name and Number: Standard Senson 25	Report # 13

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 44%. LEL 25 ft from well 25 0%. 2-7/8" - Shut in. 7" - 560 psi.
		11-3/4" - 460 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	8:30	Greased Rotac valves on kill line. Made up wash assembly BHA. Stabbed injector. Tested stripper and outside Rotac valve to
		300 psi low and 4,000 psi high. Test good. Tested BPV 300 psi low and 4,000 psi high. Test good. Broke circulation in riser
		at 1 bpm. Maintained 2,800 psi back pressure with choke.
8:30	9:00	Held BOP drill with essential personnel.
9:00	10:00	Ran in hole to swab valve. Pumped 3 bbls of glycol and displaced out of the reel with 19 bbls 10.8 ppg CaCl2.
10:00	16:00	Held PJSM. Applied 3,000 psi on riser. Opened swab valve. Pressure stabilized at 2,700 psi. Began washing down at 3/4 bpm
		maintaining 2,900 psi with choke. Pump pressure 6,500 psi. Tagged up at 20 ft. Washed down to 53 ft. Pumped 5 bbls glycol.
		Displaced out of the coil with 19 bbls of 10.8 ppg CaCl2. Shut down. Applied 3,300 psi pressure. Waited 10 minutes. Pressure
		decreased to 2,800 psi. Continued washing down at 3/4 bpm holding 2,800 psi back pressure. Found bottom of hydrate plug
		at 188 ft. Continued washing down. At 482 ft choke pressure decreased to 1,200 psi. Unable to maintain back pressure. Lost
		returns. Experienced drag. Continued pumping without returns. Pulled coil tubing up into riser. Began pumping down tubing
		tubing head outlet. At 2 bpm PP - 41 psi. At 4 bpm PP - 120 psi. Continued pumping down tubing at 1 bpm waiting on polymer
		pill.
16:00	17:30	Began pumping polymer pill 4 bpm. Pump pressure 100 psi. Pumped total of 62 bbls. Gas activity from fissures increased.
		Observed polymer from fissures around cellar. Shut down pumping operations. Tubing pressure 0 psi. Evacuated personnel.
		11-3/4" - 64 psi. 7" - 305 psi. Flowed gas from 7" and 11-3/4" annulus to open top tank. Activity from fissures appeared to
		decrease. Shut in well. 7" - 262 psi. 11-3/4" - 71 psi.
17:30	18:00	Attended end of the day meeting. Discussed running caliper tool on slick line to determine restriction at 482 ft.
		Pumped approxiamtely 200 bbls without returns.
18:00	18:15	Traveled to hotel.

Date:	7-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	14

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 54%. LEL 25 ft from well 25 49%. 2-7/8" - 940 psi. 7" - 229 psi.
		11-3/4" - 60 psi. Could not start equipment due LEL levels.
6:30	7:00	Attended morning operations meeting. Discussed bleeding off tubing. Discussed removing mushroom from stripper to rig up
		slickline.
7:00	8:45	Installed gauge on tubing. Tubing pressure 1,100 psi.
8:45	9:30	Monitored well.
9:30	10:00	Tubing pressure 1,146 psi. 7" - 228 psi. 11-3/4" - 59 psi. Bled tubing to 1,110 psi. Bled gas and fluid. Shut in. 7" - 228 psi.
		11-3/4" - 59 psi. After 10 minutes tubing pressure increased to 1,161 psi.
10:00	10:30	Tubing pressure 1,170 psi. 7" - 231 psi. 11-3/4" - 60 psi. Bled tubing to 1,070 psi. Bled gas and fluid. Shut in. 7" - 231 psi.
		11-3/4" - 60 psi. After 10 minutes tubing pressure increased to 1,226 psi.
10:30	11:00	Attempted to shoot fluid levels. Could not detect fluid levels due to well noise.
11:00	14:00	Start equipment. Removed mushroom from stipper. Spotted slickline unit and rigged up. (11:45) 2-7/8" - 1298 psi. 7" - 222.
		11-3/4" 60 psi. (13:45) 2-7/8" - 1,407 psi. 7" - 227 psi. 11-3/4" - 60 psi.
14:00	15:00	Made up 4-1/16" 15M x Bowen X-over on stripper.
15:00	17:00	Made up 2.30" gauge ring. Stabbed lubricator. Tested lubricator to 300 psi low and 4,000 psi high. Test good. Equalized swab
		valve with 1,250 psi. Opened swab valve and ran in hole. Estimated fluid level - 3,750 ft. Tagged nipple profile 8,425 ft. Pulled
		out of the hole. Secured well. Laid down lubricator. 2-7/8" - 1584 psi. 7" - 217 psi. 11-3/4" - 60 psi.
17:00	17:30	Traveled to hotel.

Date:	8-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	15

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 100%. LEL 25 ft from well 25 35 - 75%. 2-7/8" - 1,660 psi. 7" - 218 psi.
		11-3/4" - 65 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	8:15	Continued monitoring LEL levels. Commenced operations.
8:15	11:15	Began making up slickline tools. Tool string: Spinner, ITL CL, Temperature, Pressure, and GR. Stabbed lubricator.
		2-7/8" - 1,681 psi. 7" - 192 psi. 11-3/4" - 62 psi.
11:15	14:15	Pressure tested lubricator to 300/4,000 psi. Test good. Equalized swab valve with 1,500 psi. Opened swab valve RIH at 50 fpm.
		sat down at 8,425 ft. (13:15) 2-7/8" - 1,615 psi, 7" - 212 psi. 11-3/4" - 65 psi.
14:15	15:45	Pulled out of the hole at 100 fpm. In lubricator. Secured well.
15:45	16:00	Laid down lubricator. Down load data. Began preparing logs. Shut down for the night.

Date:	9-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	16

Hour	Hour	Activity on Site
Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. LEL at Well 25 cellar - 100%. LEL 25 ft from well 25 35 - 75% (North side of pad). LEL around
		equipment 0%. 2-7/8" - 1,620 psi. 7" - 215 psi. 11-3/4" - 66 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	10:30	Rigged up e-line. SDI began preparing to run gyro.
10:30	11:15	Decision was made to run/noise temp. Made up noise/temp tools.
11:15	12:15	Stabbed lubricator. Tested to 300/4,000 psi. Test good. Equalized swab valve with 1,500 psi. Opened swab valve. RIH.
		Pulled out of hole to check noise/temp tools.
12:15	13:15	Pulled into lubricator. Secured well. 2-7/8" - 1,585 psi. 7" - 216 psi. 11-3/4" - 69 psi. Changed out noise/temp tools.
13:15	18:00	Stabbed lubricator. Tested to 300/4,000 psi. Test good. Equalized swab valve with 1,500 psi. Opened swab valve. RIH.
		Logged temperature down to 8,435 ft. Log noise out of the hole. Secured well. Laid down lubricator. 2-7/8" - 1,585 psi.
		7" - 218 psi. 11-3/4" - 69 psi.
18:00	18:30	Attended end of the day meeting.
18:30	18:45	Traveled to hotel.

Date:	10-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	17

Hour	Hour	Activity on Site
Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. LEL at Well 25 cellar: 75 - 100%. LEL 25 ft from well 25 25 - 75%. 2-7/8" - 1,624 psi. 7" - 211 psi.
		11-3/4" - 70 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	9:30	SDI prepared to run gyro.
9:30	12:00	Stabbed lubricator. Tested lubricator to 300/4,000 psi. Test good. Equalized swab valve with 1,500 psi. Opened swab valve.
		RIH. Attempted to orient gyro. Unsuccessful. Pulled out of the hole.
12:00	14:00	Tested gyro. Cut 300 feet of e-line. Made up gyro.
14:00	16:00	Stabbed lubricator. Tested lubricator to 300/4,000 psi. Test good. RIH. Could not orient gyro. Well temperature and vibrations
		affecting tool. Pulled out of the hole.
16:00	17:00	Secured well. Laid down lubricator. Rigged down SDI.
17:00	17:45	Attended end of the day meeting. Located 2-7/8" EZSV in Longview, Texas.
17:45	18:00	Traveled to hotel.

Date:	11-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	18

Hour	Hour	Activity on Site
Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Took LEL readings. Cleared location to begin work. 2-7/8" - 1,705 psi. 7" - 227 psi.
		11-3/4" - 75 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	12:00	Drained riser to vac truck. Nippled down coil tubing BOP's. Nippled down riser and 4-1/16" 10M gate valve. Installed 2-9/16" 5M
		gate valve on swab valve. Installed 2-9/16" 5M x Bowen adapter flange. Tested to 300 psi low and 5,000 psi high. Test good.
		Talked with Western Wireline representative. Ordered out 2 Baker 5 setting tools to set 2-7/8" EZSV. Halliburton is flying
		2 2-7/8" EZSV's from Longview, Texas and setting sleeves from Utah. Tools will arrive tonight. Bridge Plug conversion kits
		are being machined in Ventura, California.
12:00	15:00	Back loaded slickline unit and sent to staging area. Back loaded lateral lines from well 25. Pulling 10.8 ppg CaCl2 from frac tank.
		Will cut to 9.4 ppg.
15:00	15:30	2-7/8" - 1,707 psi. 7" - 229 psi. 11-3/4" - 85 psi. Flowed 11-3/4" casing for 5 minutes on 32/64 choke. Flowing casing pressure
		69 psi. Shut in. 11-3/4" - 85 psi. Flowed 7" casing on 28/64 choke for 15 minutes. Flowing casing pressure - 200 psi.
		Shut in 7" casing pressure 220 psi. 2-7/8" - 1,703 psi. 7" - 220 psi. 11-3/4" - 84 psi.
15:30	17:00	Continued removing equipment from location in preparation for kill.
		Discussed kill plan with SCGC representative.
17:00	17:30	Traveled to hotel.

Date:	12-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	19

Hour	Hour	Activity on Site
Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Took LEL readings. Cleared location to begin work. 2-7/8" - 1,737 psi. 7" - 240 psi.
		11-3/4" - 108 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	11:15	Two 2-7/8" EZSV's arrived on location. Baker 5 setting tool arrived on location. Stabbed lubricator. Tested to 300/4,000 psi
		with HAL pump. Test good. Laid down lubricator. Made up 2-7/8" EZSV. Tested lubricator to 400/4,000 psi. Test good.
11:15	15:00	Equalized swab valve with 1,500 psi. Opened swab valve. RIH. Set EZSV at 8,393 ft. Pulled out of hole.
15:00	15:30	2-7/8" - 1,694 psi. 7" - 245 psi. 11-3/4" - 105 psi. Bled tubing to 1,195 psi. Shut in. 2-7/8" - 1,195 psi. 7" - 245 psi. 11-3/4" -
		105 psi.
15:30	16:00	Attended end of the day meeting. Discussed perforating tubing and kill plan.
16:00	16:30	Traveled to hotel.

Date:	13-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	20

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Took LEL readings. Cleared location to begin work. 2-7/8" - 1,202 psi. 7" - 229 psi.
		11-3/4" - 89 psi.
6:30	7:00	Attended morning safety/operations meeting. Discussed perforating tubing and pumping kill.
7:00	9:00	Installed targeted 90 on wellhead flowline. Stabbed lubricator. Tested to 300/4,000 psi. Test good. Equalized swab valve with
		1,200 psi. Opened swab valve. Tubing pressure 1,201 psi. Pumped 6 bbls of 10.8 ppg CaCl2. 2-7/8" - 908 psi. 7" - 229 psi.
		11-3/4" - 90 psi.
9:00	11:15	RIH with tubing punch. Tagged EZSV at 8,402 ft. Perforated tubing 8,387 ft to 8,391 ft. Pulled out of hole. Laid down lubricator.
11:15	14:00	2-7/8" - 1,526 psi. 7" - 253 psi. 11-3/4" - 89 psi. Held PJSM. Pumped 10 9.4 ppg polymer pill. Began displacing with 9.4 ppg
		CaCl2. After displacing tubing volume opened choke on 7" casing. Pump rate 6 bpm. PP - 166 psi. After 80 bbls displaced
		observed increased gas flow and liquid from fissures. Pump rate 8.0 bpm. PP - 1,500 psi. Continued pumping at 8.0
		bpm. After 185 bbls pumped. Pump pressure - 1,400 psi. Pony motor went down. 7" - 45 psi. 11-3/4" - 45 psi. Pumps offline.
		Brought pumps online at 7 bpm. Pump pressure 0 psi. After 210 bbs pumped. Pump pressure 203 psi. After 320 bbls pumped
		PP - 634 psi. Brine, oil, and gas flowing from fissures on pad. After 693 bbls pumped 10 bbls 9.4 ppg polymer pill.
		Displaced into tubing with 3 bbls. Shut down. Tubing pressure 0 psi. 7" - 192 psi. 11-3/4" - 92 psi.
14:00	17:00	Lined up to pump down 2-7/8" x 7" annulus. Pumped junk shot. After 5 bbls pumped observed brine from fissures. Continued
		pumping junk shots. Shut down. 2-7/8" - 278 psi. 7" - 293 psi. 11-3/4" - 42 psi.
17:00	17:45	Attended end of the day meeting. Discussed pumping junk shot to plug hole in 7" casing and pumping barite pill
		out of perfs in tubing.
17:45	18:00	Traveled to hotel.

Date:	14-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	21

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Took LEL readings. Cleared location to begin work. 2-7/8" - 1,610 psi. 7" - 245 psi. 11-34" - 35 psi.
6:30	7:30	Checked pressures on Well 25A: 2-7/8" - 680 psi. 8-5/8" - 80 psi. Checked pressures on Well 25B: 2-7/8" - 2,375 psi.
		8-5/8" - 1,500 psi.
7:30	8:30	Bled Well 25 7" annulus from 245 psi to 200 psi. Bled gas. Shut in and monitored.
8:30	16:30	Cleaned location and equipment. Discussed pumping barite pill with SCGC representatives. Created program for pumping
		barite pill. Gave to SCGC for review. Perfomed pilot tests with chemicals for 18.0 ppg pill. Samples proved to be pumpable
		with good settling times. (15:15) Well 25: 2-7/8" - 1.690 psi. 7" - 213 psi. 11-3/4" - 32 psi. Moved in and rigged up HAL
		batch mixer. Sucked out Well 25 cellar. 11-3/4" casing valve is covered with silt. Ordered out Super Sucker.
16:30	18:00	Filled frac tank on Pad 25 with 500 bbls 9.4 ppg brine. Modified pump line to pump junk shots down 7" annulus.
18:00	18:15	Traveled to hotel.

Date:	15-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	22

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Took LEL readings. Cleared location to begin work. 2-7/8" - 1,607 psi. 7" - 217 psi. 11-34" - 32 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	7:45	Cleaned location.
7:45	10:30	Began moving chemicals for barite pill to pad 25. Began mixing 22 bbl 18.0 ppg barite pill. Held PJSM.
10:30	11:15	Began pumping 9.4 ppg CaCl2. Initial pump pressure - 1,645 psi. Staged pumps up to 5 bpm. After 50 bbls pumped PP - 83 psi.
		Increased pump rate to 8 bpm. After 75 bbls pumped PP - 1,305 psi. Gas rate from fissures increased followed by oil and brine.
		After 170 bbls pumped PP - 1,550 psi. Pumped 19 bbls 18.0 ppg barite pill. Began displacing with 9.4 ppg CaCl2 at 8.0 bpm.
		PP - 220 psi. After displacing 35 bbls PP - 1,367 psi. After displacing 45 bbls PP - 1,500 psi. After displacing 50 bbls pump
		pressure 1,250 psi. (11:15) Shut down. 2-7/8" - 0 psi. 7" - 107 psi. 11-3/4" - 22 psi.
11;15	14:00	Monitored well. Flow from fissures stopped briefly and then began flow gas. (12:20) 2-7/8" began increasing. 7" - 205 psi.
		11-3/4" - 35 psi. (13:00) 2-7/8" - 220 psi. 7" - 190 psi. 11-3/4" - 38 psi. (14:00) 2-7/8" - 600 psi. 7" - 190 psi. 11-3/4" - 40 psi.
		(15:00) 2-7/8" - 980 psi. 7" - 220 psi. 11-3/4"- 39 psi. (16:00) 2-7/8" - 1159 psi. 7" - 251 psi. 11-3/4" - 37 psi.
14:00	14:30	Attended end of the day meeting. Discussed pumping another barite pill. Will pump 35 bbl 18.0 ppg barite pill.
14:30	14:45	Traveled to hotel.

Date:	16-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	23

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 ft from well 0 to 100%. LEL around equipment 0 - 75%. 2-7/8" - 1,688 psi. 7" - 218 psi. 11-3/4" - 33 psi.
6:30	7:00	Attended morning safety/operations meeting. Will wait for LEL readings to decrease before starting equipment.
7:00	13:00	Continued monitoring LEL's around location. Cleaned e-line unit in preparation for logging operations. Filled batch mixer with 22
		bbls fresh water. Transported barite pill materials to pad 25. Prepared barite pill program and submitted to SCGC for review.
		Continued cleaning equipment and location.
13:00	13:30	Operations were shut down for the day due to LEL levels. Assisted with DOGGR afternoon survey. 2-7/8" - 1,696 psi. 7" - 211
		psi. 11-3/4" - 33 psi.
13:30	13:45	Traveled to hotel.

Date:	17-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	24

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 ft from well 0 to 100%. LEL around equipment 0 - 77%. Winds out of the North 40 - 50 mph.
		2-7/8" - 1668 psi. 7" - 204 psi. 11-3/4" - 35 psi.
6:30	7:00	Attended morning safety/operations meeting. Decision was made to wait for LEL levels to subside before starting equipment.
7:00	11:00	Escorted HAL and T&T crane personnel to wellsite to inspect equipment.
11:00	14:00	Talked with B&C Houston about relief well trajectories. Provided surface locations and Well 25 survey data.
14:00	14:30	Escorted DOGGR representatives to Well 25 for afternoon survey. Decision was made to end operations for the day due to LEL
		levels. 2-7/8" - 1,688 psi. 7" - 209 psi. 11-3/4" - 32 psi. Secured location. Placed absorbent boom across access road.
14:30	15:00	Attended end of the day meeting with state agency representatives and SCGC.
15:00	15:15	Traveled to hotel.

Date:	18-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	25

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 feet from well - 0 to 100%. LEL level around equipment 0 - 100%. 2-7/8" - 1,597 psi. 7" - 199 psi. 11-3/4" - 34 psi.
6:30	7:00	Attended morning safety/operations meeting. Discussed pumping barite pill.
7:00	8:00	Identified location north of well pad 25 to spot pump, frac tanks, and batch mixer. Began preparing location for equipment.
8:00	9:00	Continued monitoring LEL around well pad 25.
9:00	10:00	Began mixing 35 bbls 18.0 ppg barite pill. Began pumping 9.4 ppg CaCl2 down tubing. Began pumping at 0.5 bpm. Pump
		pressure - 1,650 psi. Staged pumps to 5 bpm. After 50 bbls pump pressure - 65 psi. Shut down. Perforations clear. Well
		unloaded tubing.
10:00	10:15	Held PJSM.
10:15	11:00	Began pumping 9.4 ppg CaCl2. Staged pumps up to 6.0 bpm. PP - 125 psi. At 45 bbls pumped gas increased from fissure.
		Observed brine and oil from fissure. After 65 bbls pumped increased pump rate to 8 bpm. PP - 225 psi. At 70 bbls pumped PP
		increased to 987 psi. After 100 bbls pumped PP - 1,116 psi. After 130 bbls pumped increased pump rate to 9.0 bpm. PP -
		1,838 psi. At 230 bbls pump PP - 1,830 psi. Winds began shifting out of the North. Pumped 35 bbl 18.0 ppg barite pill. Displaced
		with 13 bbls at 8.0 bpm. PP - 1,333 psi. Pumped 17 bbls at 6.0 bpm. Pump pressure 123 psi. Pumped 10 bbls at 4 bpm.
		PP - 74 psi. Pumped 10 bbls at 1 bpm. PP - 68 psi. Total volume displaced 50 bbls. Shut down. Pump pressure 0 psi.
11:00	16:30	Monitored well. 2-7/8" - 36 psi. 7" - 190 psi. 11-3/4" - 48 psi. (11:30) 2-7/8" 45 psi. 7" - 175 psi. 11-3/4" - 40 psi. (12:30)
		2-7/8" - 80 psi. 7" - 150 psi. 11-3/4" - 40 psi. (13:30) 2-7/8" - 90 psi. 7" - 220 psi. 11-3/4" - 40 psi. (14:30) 2-7/8" - 100 psi.
		7" - 240 psi. 11-3/4" - 34 psi. (15:30) 2-7/8" - 108 psi. 7" - 265 psi. 11-3/4" - 38 psi. (16:30) 2-7/8" - 110 psi. 7" - 241 psi.
		11-3/4" - 32 psi.
16:30	17:30	Spotted slickline unit. Cleaned equipment. Work continued on secondary pumping location.
17:30	17:45	Traveled to hotel.
		B&C Houston prepared preliminary relief well plots and submitted to SCGC.

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Date: 19-Nov-2015	**Well Name and Number:** Standard Senson 25	Report #	26

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 feet from well - 0 to 100%. LEL level around equipment 0 - 65%. 2-7/8" - 138 psi. 7" - 210 psi. 11-3/4" - 28 psi.
6:30	7:00	Attended morning safety/operations meeting. Discussed cleaning equipment and moving equipment to SS-1.
7:00	13:00	Began rigging down batch mixer and pump truck. Cleaned equipment. Moved out batch mixer for cleaning. Began making up
		2-7/8" pump line from SS-1 to SS-25. Prepared SS-1 for equipment. Completed pump line.
13:00	14:00	Installed night cap with pressure gauge on SS-25. Tubing pressure 1,600 psi. Trouble shoot manifold tubing pressure gauge.
14:00	17:00	Moved 2 500 bbls frac tanks, batch mixer and HAL Elite pump truck to SS-1. Continued cleaning equipment at SS-25.
17:00	17:15	Traveled to hotel.

Date: 20-Nov-2015	**Well Name and Number:** Standard Senson 25	Report #	27

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 feet from well - 0 to 100%. LEL level around equipment 0 - 100%. 2-7/8" - 1,630 psi. 7" - 208 psi. 11-3/4" - 26 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	7:30	Placed barrier across road to pad 25 to prevent vehicles from entering. High LEL reading across road.
7:30	11:30	Modified manifold on well 25 to allow flowing 2-7/8" tubing to withdraw line.
11:30	12:00	Escorted ER team to pad 25 for assessment.
12:00	13:00	Checked pressure on Well 25A: 2-7/8" - 620 psi. 8-5/8" - 43 psi. Checked pressure on well 25B: 2-7/8" - 2,300 psi. 8-5/8" -
		1,850 psi.
13:00	17:00	Moved in 2-7/8" pump line to well 25. Continued preparing SS-1 site for pumping operations. Filled one 500 bbl frac tank with 9.4
		ppg CaCl2. Filled one 500 bbl frac tank with fresh water. Spotted additional 500 bbl frac tank. Will fill with fresh water.
		GEO Zan polymer arrived. Continued working on kill program.
17:00	17:15	Traveled to hotel.

Date: 21-Nov-2015	**Well Name and Number:** Standard Senson 25	Report #	28

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.
		LEL level 25 feet from well - 0 to 100%. LEL level around equipment 0 - 52%. 2-7/8" - 1,628 psi. 7" - 204 psi. 11-3/4" - 29 psi.
6:30	7:00	Attended morning safety/operations meeting.
7:00	8:30	Rigged up Batch Mixer and Pump Truck at SS-1. Reconfigured pump line at SS 25 to pressure test lubricator at SS 25A and
		SS 25B wells.
8:30	9:30	Installed uni-bolt adapters on SS 25A and SS 25B. Completed 2-7/8" pump line tie in at SS 25.
9:30	11:30	Moved out pump truck from 25 pad. Sent to decon. Removed pump line from CT reel. Moved out man lift. Sent to decon.
11:30	12:30	Lunch.
12:30	16:30	Repositioned Pump Truck at SS-1. Tested 2-7/8" pump line to 300/4,000 psi. High test failed. Trouble shoot leaks. Tightened
		2-7/8" connections. Moved in and rigged up 40T crane at SS 25. 2-7/8" - 1,661 psi. 7" - 194 psi. 11-3/4" - 26 psi.
16:30	17:00	Attended end of the day meeting.
17:00	17:15	Traveled to hotel.
		(12:00) John Hatteberg arrived at LAX. (15:00) Arrived at hotel. Reviewed survey data. Submitted discussion points to SCGC.
		Danny Walzel and John Hatteberg will meet at SCGC Chatsworth office at 08:00 to discuss operations to date.

Date: 22-Nov-2015		Well Name and Number: Standard Senson 25	Report # 29
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. Winds predominately out of the North. Took LEL readings. LEL level at the cellar - 100%.	
		LEL level 25 feet from well - 0 to 100%. LEL level around equipment 0 - 49%. 2-7/8" - 1,628 psi. 7" - 204 psi. 11-3/4" - 29 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	9:00	Monitor LEL levels. Began rigging up slickline to run tubing plugs in SS 25A and SS 25B. Danny Walzel and John Hatteberg	
		met Alan Gosse and SCGC representatives at Chatsworth office to discuss relief well planning.	
9:00	13:00	Well 25B: RIH with 2.3" gauge ring to 8,372 ft. Pulled out of the hole. Ran in the hole with PX plug and set at 8,372 ft. Ran and	
		set prong.	
13:00	16:15	Well 25A: RIH with 2.8" gauge ring to 8,144 ft. Pulled out of the hole. Ran in the hole with PX plug and set at 8,144 ft. Pulled	
		out of the hole. Ran in the hole with prong. Prong did not set in PX plug. Pulled out of the hole. Tested 2-7/8" pump line to	
		300/,5000 psi. Test good.	
16:15	17:30	Laid down lubricator. Repositioned Grease Pack Unit. Will re-run prong in the morning. 2-7/8" - 1,646 psi. 7" - 199 psi.	
		11-3/4" - 25 psi.	
17:30	17:45	Traveled to hotel.	
		John Hatteberg continued reviewing survey data. Entered data into compass. Ran anti-collision against SS 25 and relief well.	
		Determined which wells need to be re-surveyed. Began relief well plan.	

Date: 23-Nov-2015		Well Name and Number: Standard Senson 25	Report # 30
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. Winds predominately out of the South East. Took LEL readings. LEL level at the cellar - 100%	
		LEL level 25 feet from well - 0 to 24%. LEL level around equipment 0%. 2-7/8" - 1,624 psi. 7" - 202 psi. 11-3/4" - 29 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	8:30	Rigged up slickline on well SS 25A. RIH with prong. Set in PX plug at 8,144 ft. Pulled into lubricator. Bled tubing from 580 psi	
		to 560 psi. Rigged down slickline. Moved in second HAL Elite pump truck to SS-1 and rigged up.	
8:30	14:00	Back loaded slickline unit and equipment. Sent to decon. Back loaded injector, guide, control cab, power pack, generator, and	
		tool house. Sent to decon. Rigged down 40T crane and moved out. Survey crew took surveyed surface coordinates for SS-25.	
		Installed anchor chains around Well 25. Left loose.	
		Moved in nitrogen truck and blew out coil tubing. Back loaded reel and sent to decon.	
14:00	14:30	Pressure tested second HAL Elite pump line to 300/5,000 psi. Test good.	
14:30	16:00	Anchored 2-7/8" pump line. Secured 2-7/8" pump line at pad 25 with concrete blocks.	
16:00	17:00	Rigged down 100T crane and moved out. Prepared location for kill.	
17:00	17:15	Traveled to hotel.	
		John Hatteberg continued working on the data base, relief well directional plan. Discussed forward operations.	

Date: 24-Nov-2015		Well Name and Number: Standard Senson 25	Report # 31
Well Summary			
Standard Senson 25 has broached to surface with several fissures on pad site.			
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.			
Hour	**Hour**	**Activity on Site**	
5:45	6:00	Traveled from hotel to location.	
6:00	6:30	Performed site assessment. Winds predominately out of the South East. Took LEL readings. Cleared location for personnel.	
		2-7/8" - 1,638 psi. 7" - 199 psi. 11-3/4" - 26 psi.	
6:30	7:00	Attended morning safety/operations meeting.	
7:00	8:45	Prepared for pumping operations. Held PJSM.	
8:45	9:45	Mixed 50 bbls GEO Zan polymer pill loaded with LCM. Mixed 35 bbls 18.0 ppg barite pill.	
9:45	11:45	Pumped 50 bbl GEO Zan pill. Began pumping fresh water. Began pumping fresh water at 5 BPM. Pump pressure 1,944 psi.	
		After 60 bbls pumped PP - 355 psi. Increased pump rate to 8 BPM. PP - 1,670 psi. After 80 bbls pumped increased pump rate to	
		10 BPM. PP - 2,774 psi. Gas from crater increased after 90 bbls pumped. After 135 bbls pumped increased rate to 12 BPM.	
		PP - 3,502 psi. Increased pump rate to 13 BPM. PP - 4,167 psi. Opened 7" choke after 850 bbls pump. 7" casing pressure	
		decreased from 160 psi to 8 psi. Pumped 950 bbls water. PP - 4,067 psi. Pumped 35 bbls barite pill. Displaced out of the tubing	
		with 56 bbls. Shut down. Pump pressure 0 psi.	
11:45	13:00	Monitored well.	
13:00	17:15	Tubing pressure increased to 76 psi. 7" - 188 psi. 11-3/4" - 27 psi. (17:15) 2-7/8" - 1,311 psi. 7" - 155 psi. 11-3/4" - 26 psi.	
		At time of report recovered 700 bbls of fluid from location.	
17:15	17:30	Traveled to hotel.	
		John Hatteberg continued planning relief well. Updated SHL's of offset wells and target well, corrected all well elevations, made	
		wall plot and anti collision report. Began working on final presentation.	

Date: 25-Nov-2015	Well Name and Number: Standard Senson 25	Report # 32

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Cleared location for personnel to begin work. 2-7/8" - 1,651 psi. 7" - 199 psi. 11-3/4" - 25 psi.
6:30	7:00	Attended morning operations/safety meeting.
7:00	8:00	Prepared for pumping operations. 2-7/8" - 1,643 psi. 7" - 200 psi. 11-3/4" - 25 psi.
8:00	11:00	Pumped 50 bbl GEO Zan pill loaded with LCM. Displaced with fresh water down tubing with 56 bbls at 5 BPM. IPP - 1,760 psi.
		FPP - 280 psi. Increased pump rate to 12 bpm. PP - 3,496 psi. After 60 bbls pumped increased pump rate to 13 bpm. PP -
		4,173 psi. After 140 bbls pumped gas activity increased from crater. 7" - 40 psi. After 700 bbls pump water flow from crater
		increased. Continued pumping at 13 BPM. PP - 4,164 psi. Pumped 960 bbls of water. 7" - 17 psi. 11-3/4" - 27 psi.
		Pumped 100 bbls GEO Zan pill loaded with LCM. Began displacing with 9.4 ppg CaCl2 at 4 bpm. PP - 89. After 20 bbls of
		displacement slowed pump rate to 2 BPM. PP - 20 psi. After displacing 40 bbls slowed pump to 1 bpm. PP - 0 psi. After
		displacing 56 bbls shut down. 2-7/8" - 0 psi. 7" - 0 psi. 11-3/4" - 27 psi.
11:00	16:00	Flowline from 7" and tubing head broke. Nipple on well head broke. Pump line to 7" casing head broke. Fabricated valve
		extension handles for tubing head valve and 7" casing valves.
16:00	17:00	Closed tubing head valve and 7" casing valves.
17:00	17:30	Attended end of day meeting.
17:30	17:45	Traveled to hotel.
		John Hatteberg continued working on relief well plan and presentation. Gave presentation to SCGC. Will travel to Houston
		tomorrow.

Date:	26-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	33

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Cleared location for personnel to begin work.
6:30	7:00	Attended morning operations/safety meeting.
7:00	15:45	Pilot tested Sodium Silicate delivered to location. Installed cables around wellhead to stabilize. Performed site work.
15:45	16:00	Attended end of the day meeting.
16:00	16:15	Traveled to hotel.
		John Hatteberg traveled to Houston, Texas.

Date:	27-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	34

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Cleared location for personnel to begin work.
6:30	7:00	Attended morning operations/safety meeting.
7:00	12:00	Met with crane operator and discussed location to spot 100T crane. Moved in backhoe and cleared area for crane.
12:00	12:30	Lunch.
12:30	16:45	Delivered 320 track hoe to pad 25. Began clearing around well 25. Moved in man lift. Installed hand wheel on crown valve.
		Tightened hand wheel on tree wing valve. Installed pressure gauge on night cap. Checked tubing pressure. Tubing pressure
		1,600 psi. Removed whip check from 2-1/16" 5M x 1502 adapter flange.
16:45	17:15	Attended end of the day meeting.
17:15	17:30	Traveled to hotel.

Date:	28-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	35

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. LEL's too high to run equipment.
6:30	7:00	Attended morning operations/safety meeting.
7:00	13:30	Monitored LEL's. Met with Onyx and Weatherford. Ordered out hoses for hydraulic choke. Identified rig up to flow tubing
		through hydraulic choke to test separator with the option to flow to withdraw line or open top tank. Identified rig up to flow
		7" casing through secondary test separator to open top tank. Made up 50 ft of 2" 5M co-flex hose. Met with SCGC
		representatives to discuss rig up to flow tubing to withdraw line. Discussed installing surface safety valve on tree assembly.
		Discussed re-installing relief valve on withdraw line. Located relief valve for withdraw line. Relief valve will be bench tested.
		Located surface safety valve that was removed from SS 25. Sent for bench testing.
13:30	16:00	Winds out of the North East. Moved in track hoe and backhoe. Excavated around SS 25. Cleaned east side of location.
		Performed site work.
16:00	16:15	Attended end of the day meeting.
16:15	16:30	Traveled to hotel.

Date:	29-Nov-2015	Well Name and Number:	Standard Senson 25	Report #	37

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. LEL's too high to run equipment.
6:30	7:00	Attended morning operations/safety meeting.
7:00	12:30	Continued monitoring LEL's. Installed culvert on NW corner of Pad 25. Discussed rigging up to flow Well 25 tubing to Well 25B withdraw line. Met with SCGC personnel to discuss required equipment. Replaced block valve in withdraw line. Dug out and exposed pump in manifold. Installed additional line to secure Well 25.
12:30	16:30	Moved in man lift. Moved in and rigged up 100T crane. Repositioned E-line equipment and cleaned. Steam cleaned hydraulic choke manifold and test separators. Made up noise/temp tools. Rigged down and moved out 100T crane. Moved in back hoe. Excavated around concrete pad south of well 25. Exposed wash out. Backfilled. Located grease fittings for 2-1/16" 5M safety valve. Function tested, shell tested, and block and bleed tested to 400/5,000 psi. Tests good. Sent safety valve to welder. Instructed how to tack weld ring gaskets in place. Inspected adapter flanges to rig up to Well 25 production line. Installed relief valve on production line.
16:30	16:45	Attended end of the day meeting.
16:45	17:00	Traveled to hotel.

Date: 30-Nov-2015	**Well Name and Number:** Standard Senson 25	Report # 37
Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:45	6:00	Traveled from hotel to location.
6:00	6:30	Performed site assessment. Winds predominately out of the North. LEL's too high to run equipment.
6:30	7:00	Attended morning operations/safety meeting.
7:00	10:00	Continued monitoring LEL's. Moved in man lift. Moved in and rigged up 100T crane. Stabbed lubricator. Ran in hole with noise/temp tools.
10:00	15:30	Logged temperature to 8,390 ft. Logged noise out of the hole.
15:30	16:30	Laid down lubricator. Rigged down and moved out 100T crane. Moved out man lift. Continued rigging up to flow Well 25 tubing to Well 25B production line.
16:30	17:00	Attended end of the day meeting.
17:00	17:15	Traveled to hotel.

01-Dec-2015

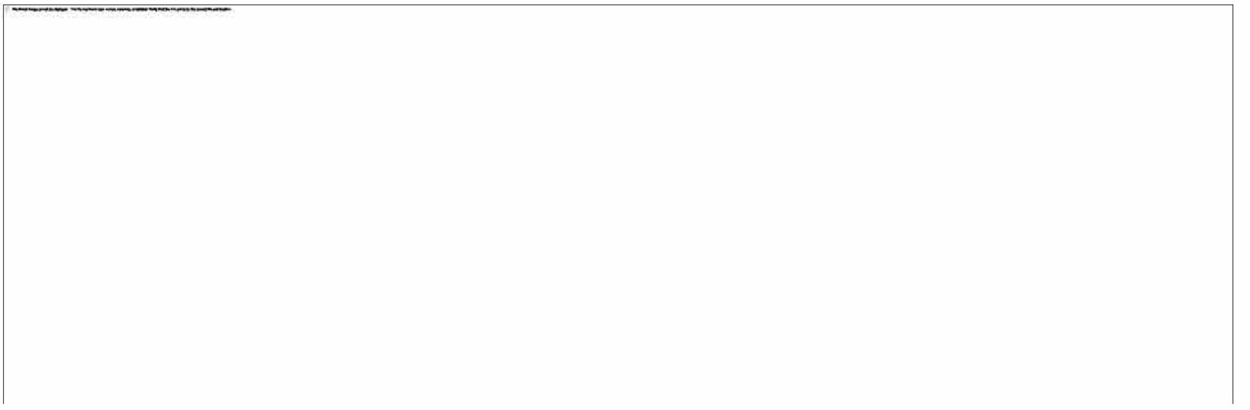
02-Dec-2015

03-Dec-2015

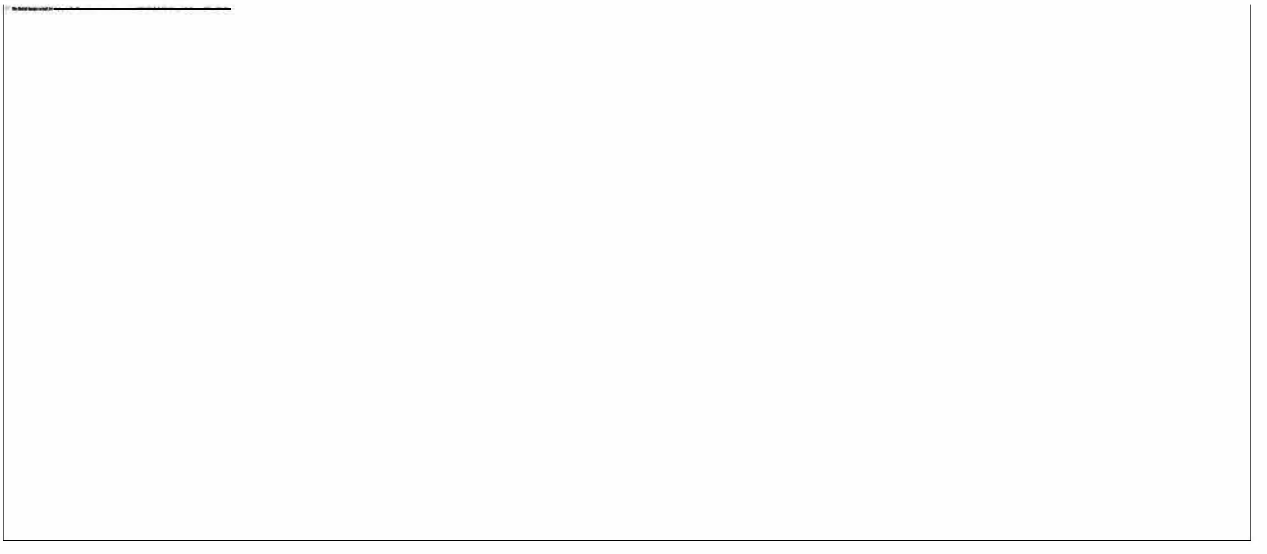
04-Dec-2015

05-Dec-2015

06-Dec-2015



07-Dec-2015



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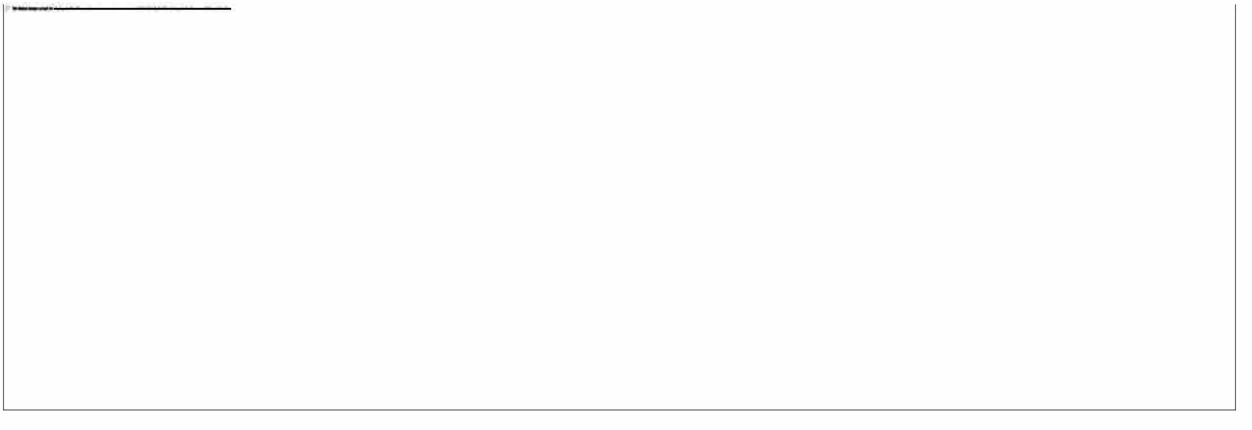

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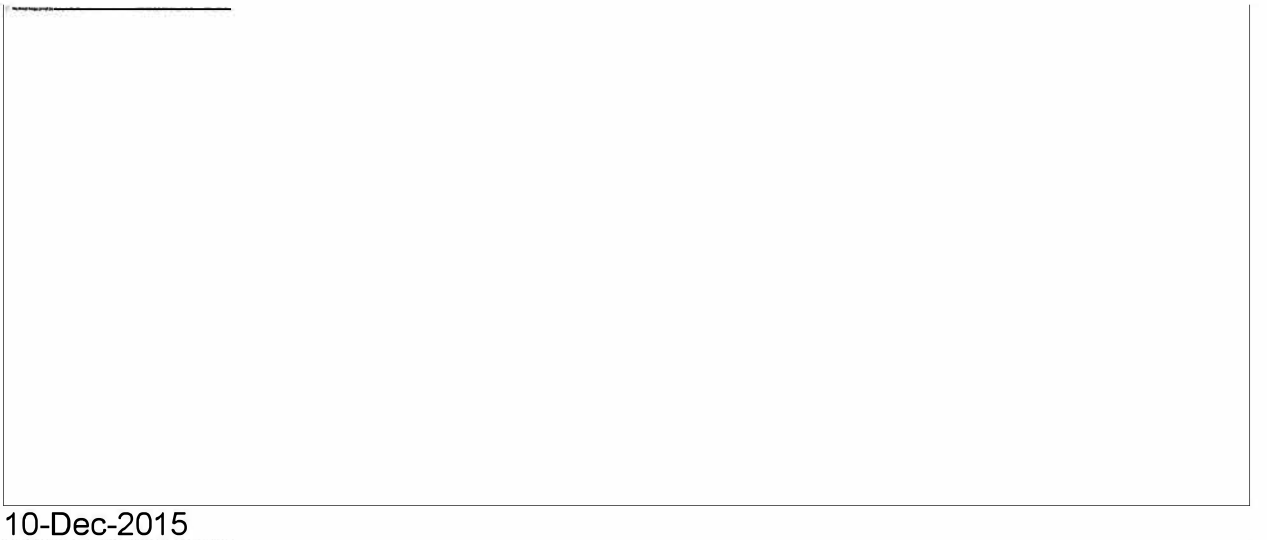

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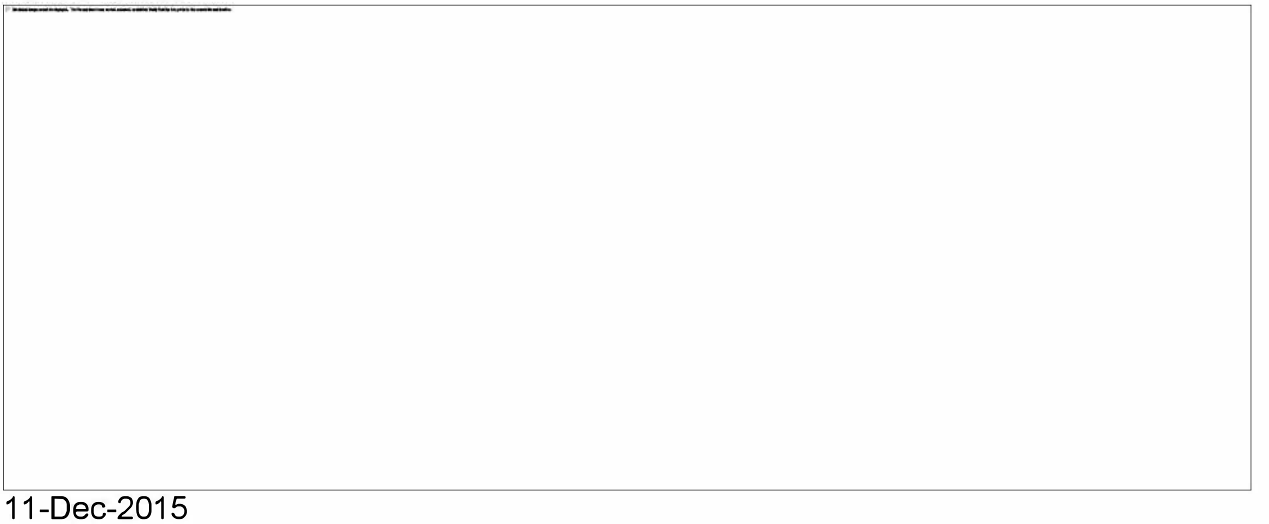
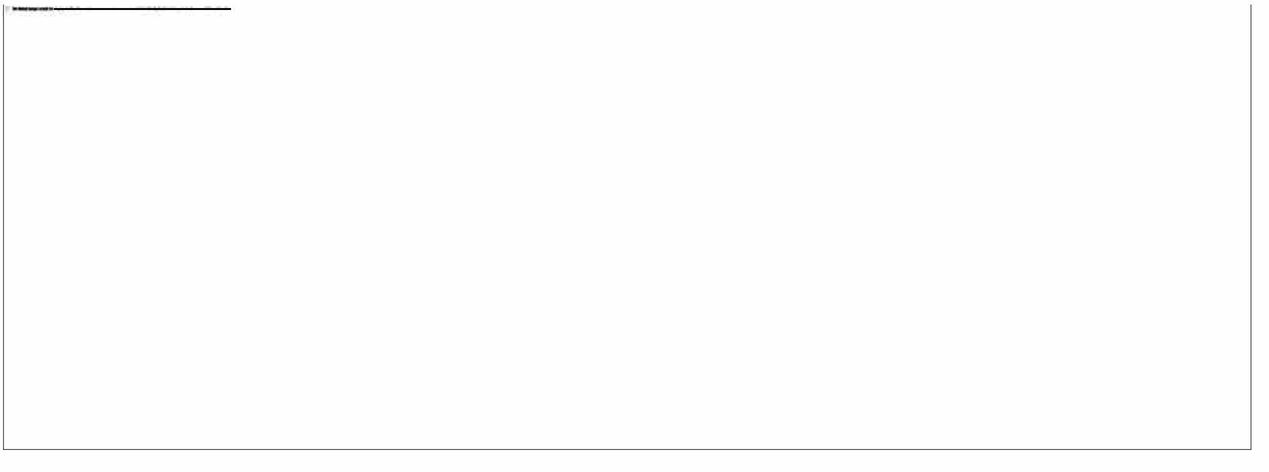


11-Dec-2015



12-Dec-2015

13-Dec-2015

Date:	16-Dec-2015	Well Name and Number:	Standard Senson 25	Report #	53

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:35		Operations Mtg w/all service companies and Dept of Oil & Gas
		Move to location. Clean eqpt and maintenance.
		Reposition chain from west side to clean mud and debris from west side of location. Can't get to southside due to north wind
11:30		Lunch
12:00		Winds become calmer and turning to the west. Western Wireline inspects its E-Line unit
		Regulators arrive on site to access well (Dept of Oil & Gas). Operations shut down for insection
13:30		Re-install stabilizing line of wellhead to east and west side of tree. Clean Swaco gauges
		Took Man-Rider to de-contamination site for cleaning.
		Start and check air compressor
17:00		Depart for hotel
		LaGrone & Gomez attend meeting for Regulators (Dept of Oil & Gas, US EPA, Ca. OSHA; Sandia, Berkley, & Lawrence-Livermore Labs)
		to discuss pumping plan on target well and ranging concepts of relief well
		Bridge was revamped for larger span. Mud mixing plant complete. Receiving mud, should receive all by Thursday.

Date:	17-Dec-2015	Well Name and Number:	Standard Senson 25	Report #	54

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:45		Arrive on SS25 location. Check LEL and wind direction. Move in crane. Held Tool Box safety mtg. Used man basket
		and take 2 personnel to tree. Used long reach track hoe to assist and undo pump lines.
		Close in upper crown valve and bleed off line, remove line. Insure that wing valve on north side is shut-in and bleed off/remove line
		Remove all pump lines on manifold. Reposition 2-7/8" pump lines from Location 1. Built new dirt bridge over pump lines.
		Break down wireline lubricator. Remove pump iron hanging in cellar. Load out same to decontamination site. Send wireline eqpt to DECON
11:30		Lunch in shifts while wireline is loaded out for DECON
12:45		Stop operations to take gas samples for LA COUNTY HAZMAT AND FIRE DEPARTMENTS
13:00		WAIT ON OSHA, NO SHOW
13:30		Commence operations on cleaning south side of wellbore
14:35		SUSPEND OPERATIONS DUE TO SMALL AIRCRAFT (Cesna 172) DOING FLY-BYS VERY CLOSE TO LOCATION
14:50		Flour Eng and AE Eng representatives arrive and stand by until plane leaves
14:55		B&C takes representatives to inspect well and are looking at ideas to capture the gas coming out of the crater (Operations stopped)
15:00		Clean on east and south side of location, preparation for bridge
16:30		Secure site for evening
17:30		Travel to Hotel
		LaGrone, Gomez, Richard meet w/ Flour Eng on building a Sombrero & installing mist extractors
		LaGrone, Gomes, Richard meet w/ California OSHA and discuss safety issues with placing bridge and kill plan
		LaGrone, Richard, Clayton meet w/ Jim Fox, Shackelford and SOCAL staff on alternatives and Contingencies

Date:	18-Dec-2015	**Well Name and Number:**	Standard Senson 25	Report #	55

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:30		Attend morning Ops meeting
6:45		Arrive on SS25 well and check LEL and wind direction, blowing from the NNW. Unable to clear debris due to strong northernly winds
		Tools taken to DECON to be cleaned. Stage junk shot manifold to SS25 site. Modified surface casing stinger sub for wellhead "A"
		Retest both pump lines from Location 1 to 300 psi LOW and 5000 psi HIGH. Good Test
12:30		Lunch
13:15		On SS25 site, check LEL's and wind direction. Move dirt to fill low places on east side. Clean remaining debris from east side
		and crater. Retighten chaines supporting tree west to east
16:00		Depart location
		Bridge is 100 % complete. As assembled, picked up for Center of Gravity (Total Weight = 15,000 lbf). Took apart the two 50 ft
		sections for transport up the hill to location. Installed pad eyes for section lift. Will be delivered to location @ 09:00 tomorrow
		B&C attend overview and troubleshooting session of options available to kill the target well from surface.

Date:	19-Dec-2015	**Well Name and Number:**	Standard Senson 25	Report #	56

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:30		Morning Operations Mtg including Oil/Gas Regulators
6:45		Arrive on location and monitor gas and slight wind direction from the south
		Complete all dirt work to accept bridge (bury 7" kill/choke lines), which is finished down the hill
8:40		Move in 220T hydraulic crane w/ 200 ft stick.
9:40		Tool box safety meeting
10:25		1/2 of bridge arrives and position
11:00		2nd 1/2 of bridge arrives and is assembled and pull tested w/ crane
11:30		Move bridge and "straddle" Well 25. No issues. Job went smooth. Bridge was weight @ 15,000 lbm
		Remove slings from BOX of bridge
12:30		Lunch
13:00		Install additional grating onto bridge around tree to congeal oil to fall back into crater and keep out of air
14:00		Rig down crane and remov from location
15:00		Shut down operatons due to wind and rain
		Attend meeting with California O&G regulators discussing merits/risks of cutting tubing prior to jet cuttin tubing
		James Bottoms w/ Western Wireline (Bakersfield) in group meeting to discuss issues around cutting tubing while it is in 10-15 M#
		compression.
17:30		Leave location and head to hotel.

Date:	20-Dec-2015	**Well Name and Number:**	Standard Senson 25	Report #	57

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.

11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:30		Depart Hotel
6:30		Attend Morning Operations meeting
6:45		Arrive on SS25 pad, check LEL and wind direction. Check Tbg Pressure of SS25=1318 psig
7:00		Function tested SSV (manumatic) valve off of casing valve twice (OK)
8:00		Move in HOWCO pump iron and tie into wireline pump-in tee. Drive in ground rod and ground Hatteberg's crossing
10:00		Move in 100T crane and set up for wireline. Ground same to bridge & earth
11:00		Spot gas/safe safe mono-condutor wireline unite
12:00		Lunch
12:35		Cont. RU W/L.
		Unable to run gauge ring and be off location prior to end of daylight
13:30		Leave W/L unit, drive crane down hill to DeCon area. All ready to RIH first thing in morning
		Secure well w/ turnbuckles on north side. Wellhead is stable and secure
		Cover wireline unit w/ plastic
14:00		Perorm general housekeeping. Operations suspended for evening
15:00		Inspetion of grating section to place over bridge for access and droplet collection
		Appears to be assiting in droplet coalesce size
		Relief well appears to be 2 ft from target on high side, running 4" gradient tool to determine exact distance to target.

Date: 21-Dec-2015 | **Well Name and Number:** Standard Senson 25 | Report # 58

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.

11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:30		Depart Hotel
6:30		Attend Morning Operations meeting, wind from the south
6:40		Tubing Pressure on SS25 is 1285 psi, est BHP is 1551 psi or 3.5 ppg equivalent
7:00		Move in crane & wireline eqpt
7:30		Place cment blocks on choke line
8:30		RU lubricator and test 400# low, 4000# high. Equalize to 1300#, open crown valve and RIH w/ 2.133" Gauge ring
9:30		Tag up @ +/-100 ft. POH & remove lubricator. Rig up on 25B (offset well on same pad close to well 25 downhole)
		for spinning magnet survey. Results showed 25B is NOT interferring with Wellspot/Gradient Runs, but actually seeing 25
14:30		Finish out of hole w/ rotating magnet, 2000# on 25B
15:00		Install additional grating on bridge for coalescing purposes (grating is knocking down the oil mist)
16:00		Move slick line eqpt and glycol pump onto location. Release crane from wellsite
16:30		Reconfigure pump tie in lines to glycol line. Equalize w/ 2000 psi and pump 1 bbl of glycol into well. No "sealing" ice plug
17:15		Leave location
		Target well is 13 ft away at TD and 18 deg left of high side

Date: 22-Dec-2015 | **Well Name and Number:** Standard Senson 25 | Report # 59

Well Summary

Standard Senson 25 has broached to surface with several fissures on pad site.

11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.

Hour	Hour	Activity on Site
5:30		Depart Hotel
6:30		Attend Morning Operations meeting, wind from the south/west variable w/ lots of fog, frequently can't see kill location
7:10		Arrive and site check wind and LEL. Clear location for Western Wireline to pump glycol. Tubing pressure is 1215 psi
		Equalize across crown valve, open same. Pump 1.5 bbl of glycol @ 7 gpm. Tubing pressure dropped to 1140 psi
8:00		Close wellhead, bleed off lines and remove chem injection pump. Call HOWCO and inform SS 25 ready for pump line test pressure
9:00		Site safety meeting
9:10		Begin Pump Line test 400 psi Hi/ 5000 psi low. While bleeding back from 5M# high @ 1200 psi, chicksan o-ring leaking on location
		Change out loop/bale
9:50		Repeat test 400/5000 with 5/10 min test, respectively. All OK
10:10		Began kill w/ 300 bbl of all WBM at 15.1 ppg at 5 BPM (100 bbl of mud, 100 bbl mud w/ 125#/bbl mud & 30 ppb Nutplug, 100 bbl of mud)
10:15		Pumping at 5 BPM thru entire job. 40 bbl gone, 150 psi on pump, 13 psi on wellhead
10:20		60 bbls pumped 200 psi
10:22		70 bbs gone, 200 psi, mud/oil mist in crater
11:05		300 bbl gone, pumps off, slow rate via low torgque to 1/2 BPM (max pressure 400 psi, min 120 psi, flat lined at 260 psi on last 60 bbl)
11:20		shut down all pumping due to rocking of wellehad and unloading mud from crater, very little formation. Similar as before
		but w/ much less fluid (mud) to surface due to 15# mud weight
13:28		Tubing pressure rose from zero to 248 psi, well contiuing to unload dehydrated/clabbarded mud
14:00		Pump line to top TEE broke off due to movement of wellehad. Close LowTorque bale on pump line to isolate manifold. Monitor well
14:30		Gather sample of mud ejected from crater. Well began to settle down, clabbard mud still being ejected
15:30		Secure well site and Demob all personnel

Date: 23-Dec-2015 | **Well Name and Number:** Standard Senson 25 | Report # 60

Well Summary		
Standard Senson 25 has broached to surface with several fissures on pad site.		
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.		
Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:30		Attend Morning Operations meeting, high wind from the north
7:10		Arrive on site and check wind and LEL's. Access to determine best way to clear debris. Crater has grown 5 ft wider and 12 ft to the north
		Later inspection showed south side of crater had large and deep hole due to 11-3/4" casing outlet. Mark safety zone on surface.
7:30		Check tbg pressure at chemical pump, 750 psi. Attempt to close valve on tree of injection tee. Grating had moved and restricted
		valve access. Isolate HOWCO pump line at well and attemp to bleed off. Couldn't bleed off, valve possible cut out
8:30		Close valve on tree by taking off handle and closing with wrench. Bleed from 800 psi to 600 psi on Tee pump line manifold.
9:00		Decide to bleed pump line at Location 1 (where HOWCO cmt trucks are)
9:50		Line up valves on Location 1, bleed same.
10:00		Check all lines on SS25 and confirm they are bled off
10:30		Clear Western Wireline to demob eqpt
11:30		Disconnect chemical inj line from pump manifold
12:30		Lunch
13:00		Wind not favorable to bring crane down to load out quipment
14:00		Continue to rig down eqpt. Kill power to site and disconnect electric wireline unit. Reconfigure power to Location 9 site down hill.
15:15		Hook T&T tractor to electric line float and remove from site
15:30		Secure and clear site of all peronnel

Date:	24-Dec-2015	**Well Name and Number:**	Standard Sesnon 25	Report #	61
Well Summary					
Standard Senson 25 has broached to surface with several fissures on pad site.					
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.					

Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:30		Morning Operations Mtg
7:00		Check wellsite for LEL's. Bring in eqpt operator to clear debris. Strong wind from the north
7:30		Pull grating skid from north end of bridge. Clear mud & debris off of bride from north and east side of bridge. Clean north bridge walk
9:30		Pull up hydraulic hoses and steel line for pressure sensor and SSV
10:30		Move in crane after wind stalled. Load out all remain W/L equipment
		Continue clearing mud off of bridge from east side of bridge. Remove skid grating from south end of bridge
11:50		Lunch
12:30		WO California OSHA for permission to return to work
13:40		Return to site, wind from the West, OK given from Cal OSHA
14:00		Flour eng visit site to access gas recovery. Continue cleaning mud (dehydrated and sticky/heavy) and debris from south and east side
		of bridge. Clear mud off of Xmas tree and haul off grating platforms for cleaning
		Haul off VOC bin full of debris
16:00		Secure site and demob site of all peronel
		Merry Xmas to all, and to all a good night

Date:	25-Dec-2015	**Well Name and Number:**	Standard Sesnon 25	Report #	62
Well Summary					
Standard Senson 25 has broached to surface with several fissures on pad site.					
11-3/4" casing to 990 ft. 7" casing to 8,585 ft. 5-1/2" slotted liner to 8,745 ft. 2-7/8" tubing to 8,510 ft. Packer depth 8,468 ft.					

Hour	**Hour**	**Activity on Site**
5:30		Depart Hotel
6:30		Morning Operations Mtg
6:45		Arrive on site and check wind and LEL levels. Strong wind from the north. Clean grating skid on north side of well. Cover with
		steel mesh (mist extractor) to catch oil droplets/mist in gas flow. Clean mud and debis off of NW side. Clean second grating of mud
		Install and strap down full length w/ SS316 mist extractor mesh. Wind unfavorable to work on south side w/ crane
14:00		Secure site and travel to hotel

26-Dec-2015

27-Dec-2015

28-Dec-2015

29-Dec-15

30-Dec-2015

31-Dec-2015

01-Jan-2016

02-Jan-2016

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07-Jan-2016

08-Jan-2016

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10-Jan-2016

12-Jan-2016

13-Jan-2016

14-Jan-2015

B. Additional relief well kill simulations

8.1 Additional simulations for 7" x 2 ⅞" annulus assuming higher KH

8.1.1 Relief well Kill simulations assumed no losses and high productivity

A constant pump rate of 10 bpm of 9.0 ppg mud was used for these simulations. Initially, after intersection is achieved, the flow rate of mud into the blowout well will be higher than 10 bpm due to the heavy overbalance. No losses are assumed and the kill mud will accumulate in the annulus.

For these simulations, the higher IPR of 13150 mD·ft was used, and the well was flowing at an initial rate of 30 mmscf/d. Even for this gas rate, the kill mud will accumulate in the annular space between the 2 ⅞" tubing and the 7" casing and the pressure response will be similar for lower productivities. Simulations show that the annulus will be filled with mud and the required kill mud volume is not much higher than the volume required to fill the wellbore. The following show the pressure response curves and volumes.

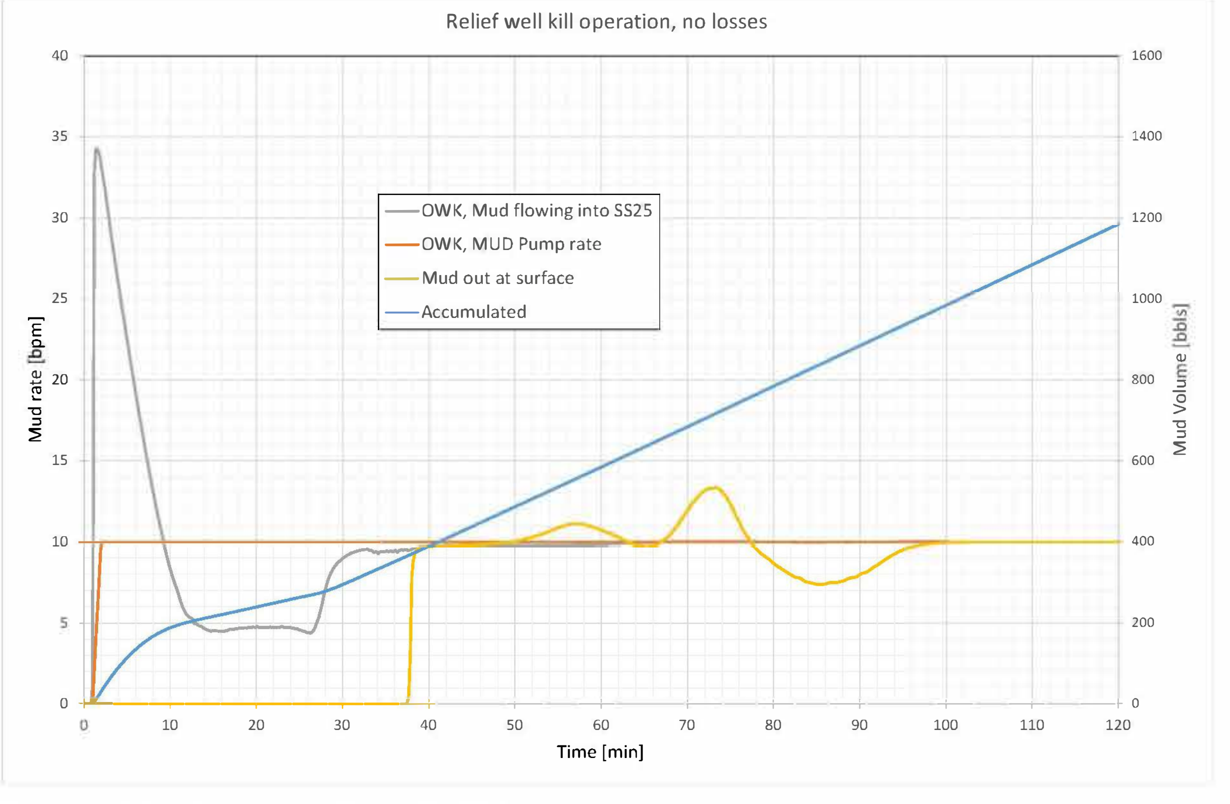

Figure B.1: Mud flow rates, RW kill, no losses

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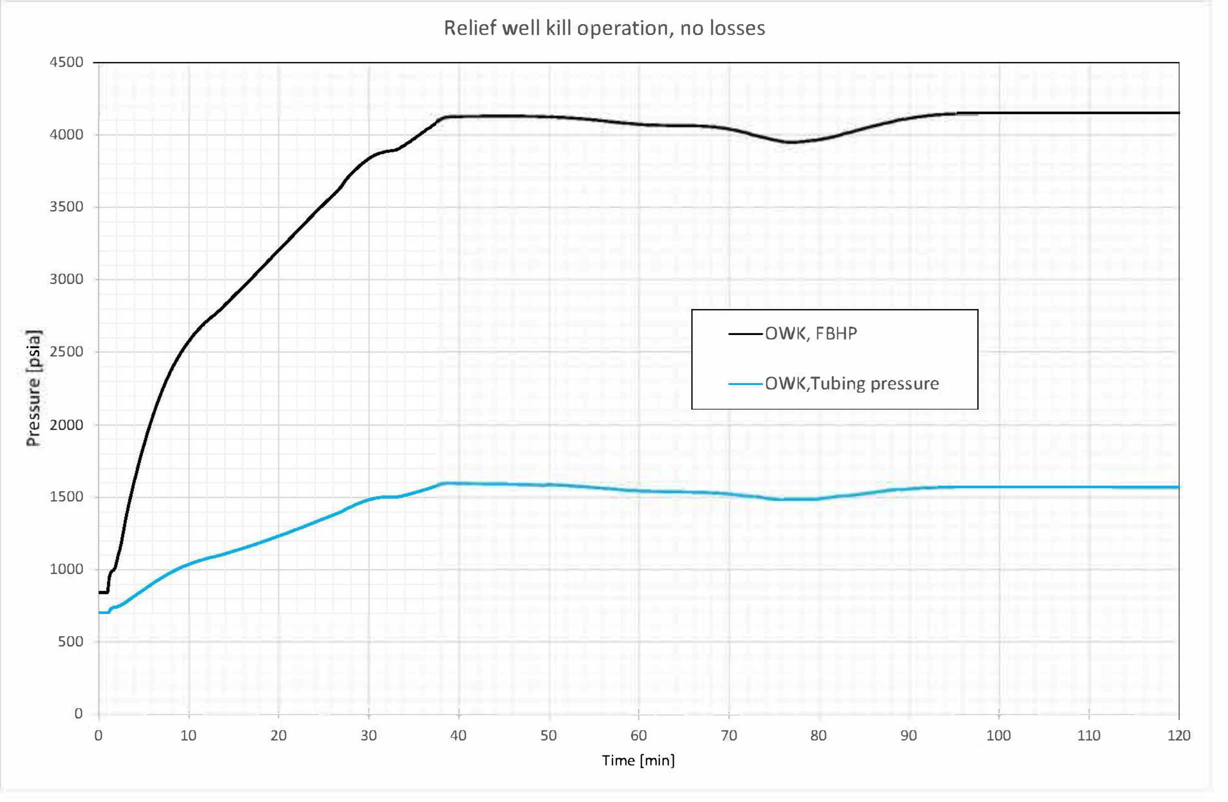

Figure B.2: Pressure response curves, RW kill, no losses

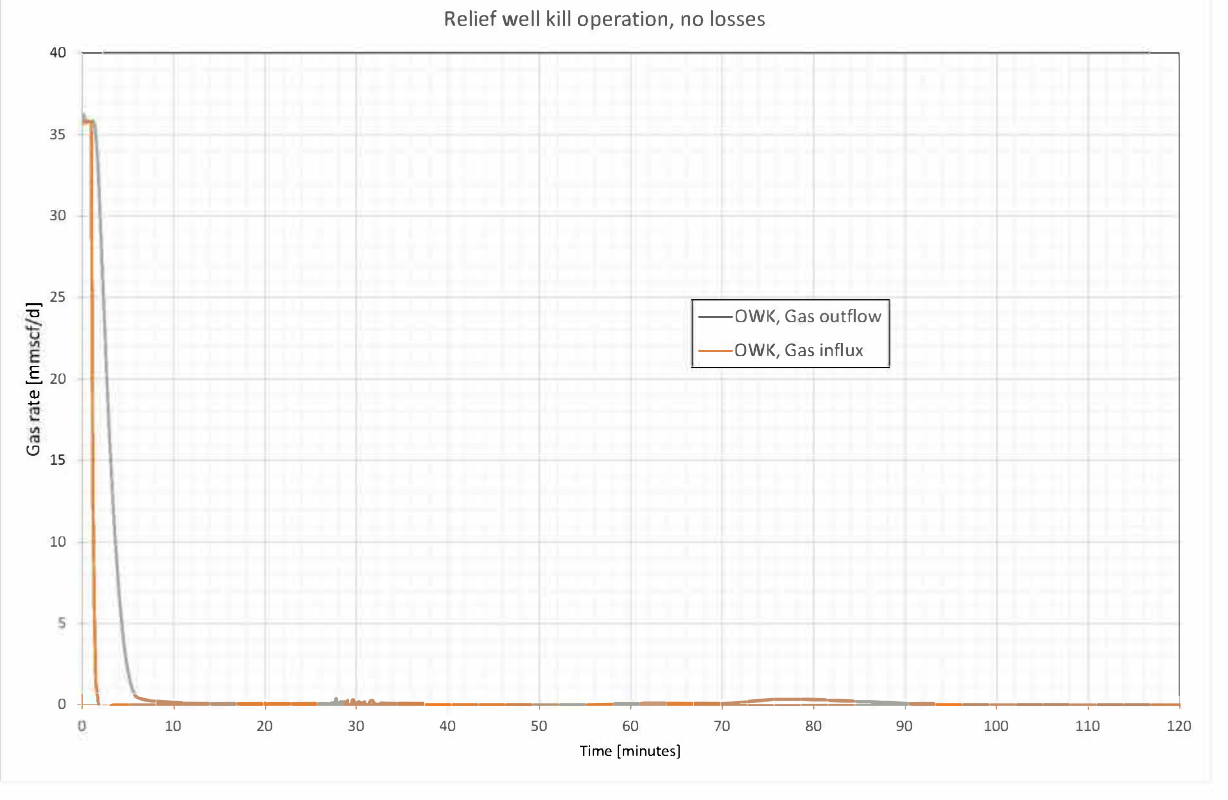

Figure B.3: Flow rates, RW kill, no losses

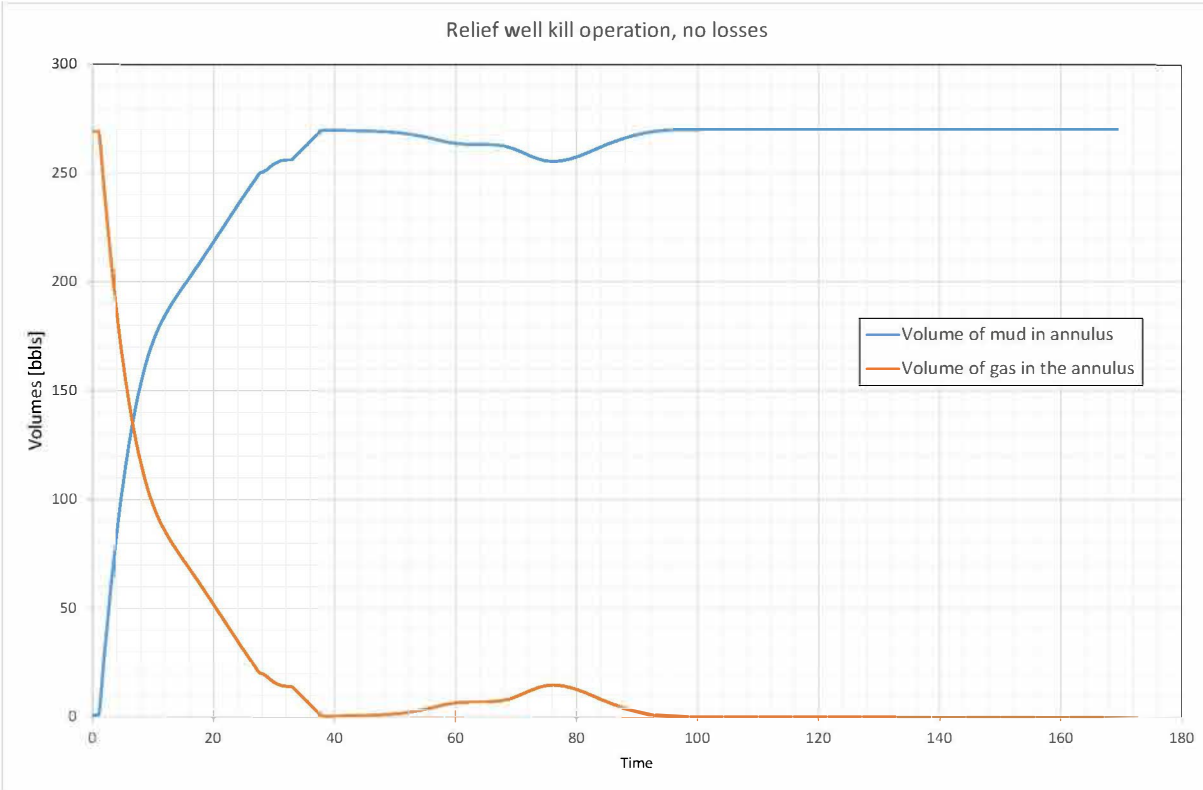

Figure B.4: Volumes, RW kill, no losses

8.1.2 RW Kill simulations, bottom hole washed out to 600 bbls, high KH

For these simulations, the hole from the top producing sand S4 and down has been assumed washed out to a total volume of 600 bbls. Simulations were similar to the previous runs using a constant pump rate of 10 bpm of 9.0 ppg mud.

The following shows the pressure response curves and volumes. As expected, a similar pressure trend is observed, but with a delay as mud will fill the washed out volume prior to flowing up the annulus.

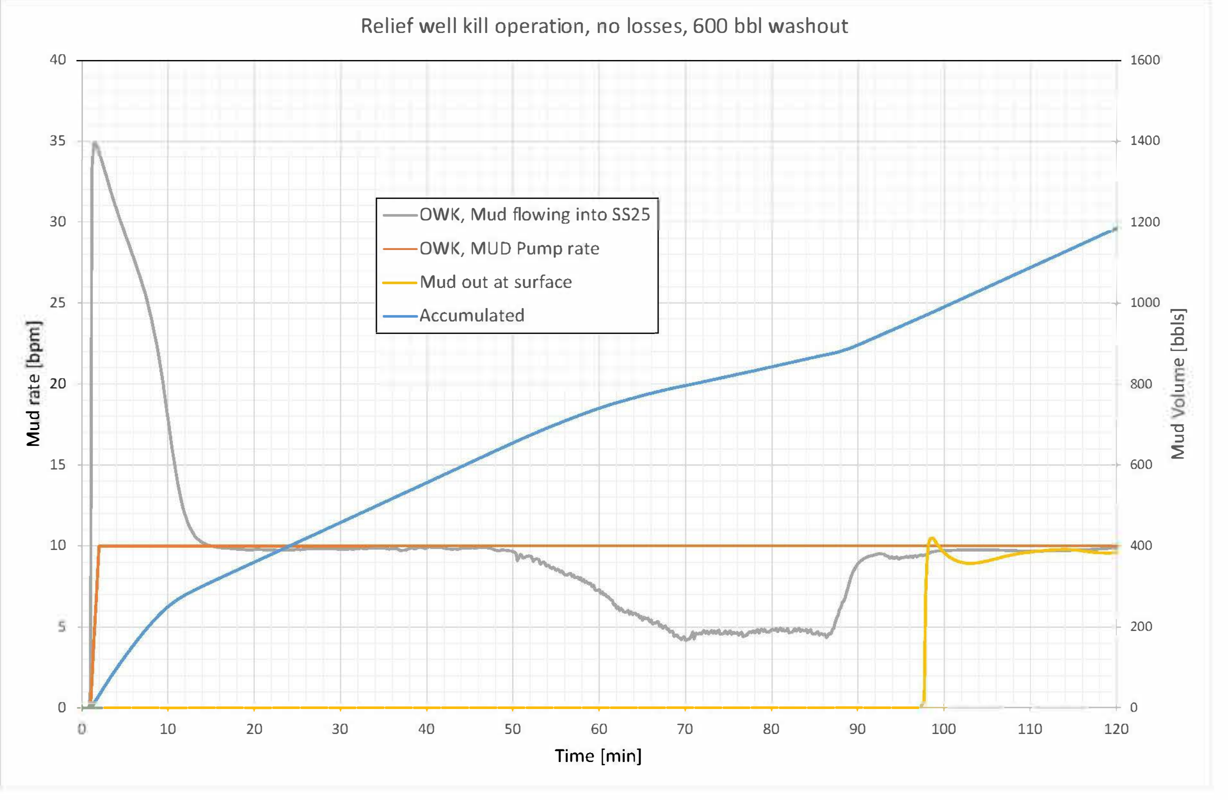

Figure B.5: Mud flow rates, RW kill, no losses, bottom washed out to 600 bbls

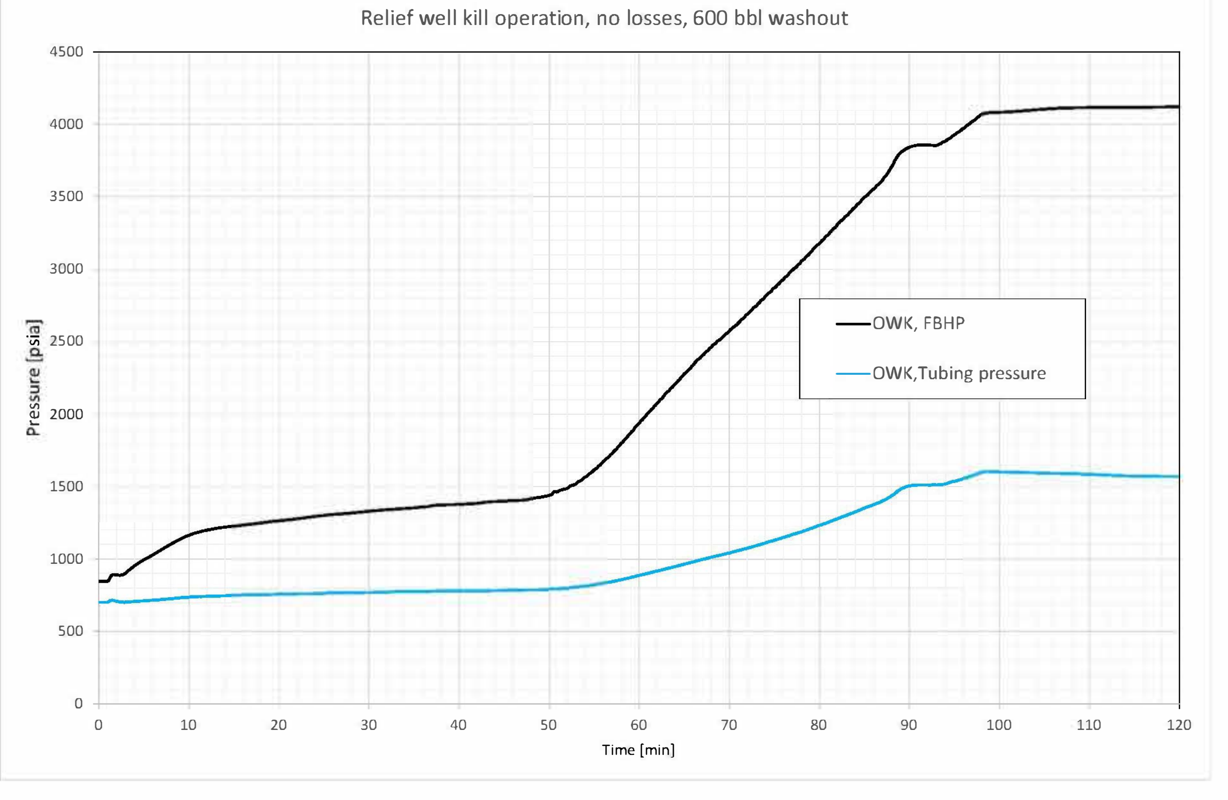

Figure B.6: Pressure response curves, RW kill, bottom washed out to 600 bbls

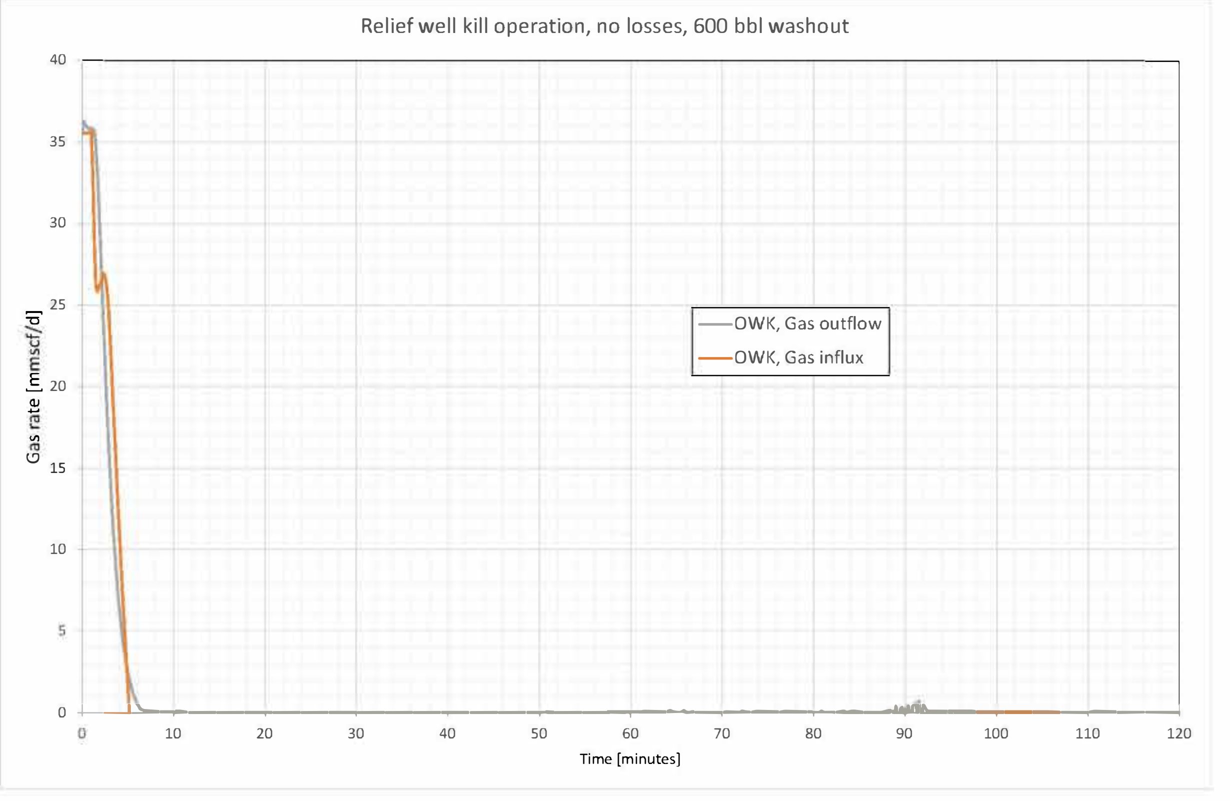

Figure B.7: Flow rates, RW kill, no losses, bottom washed out to 600 bbls

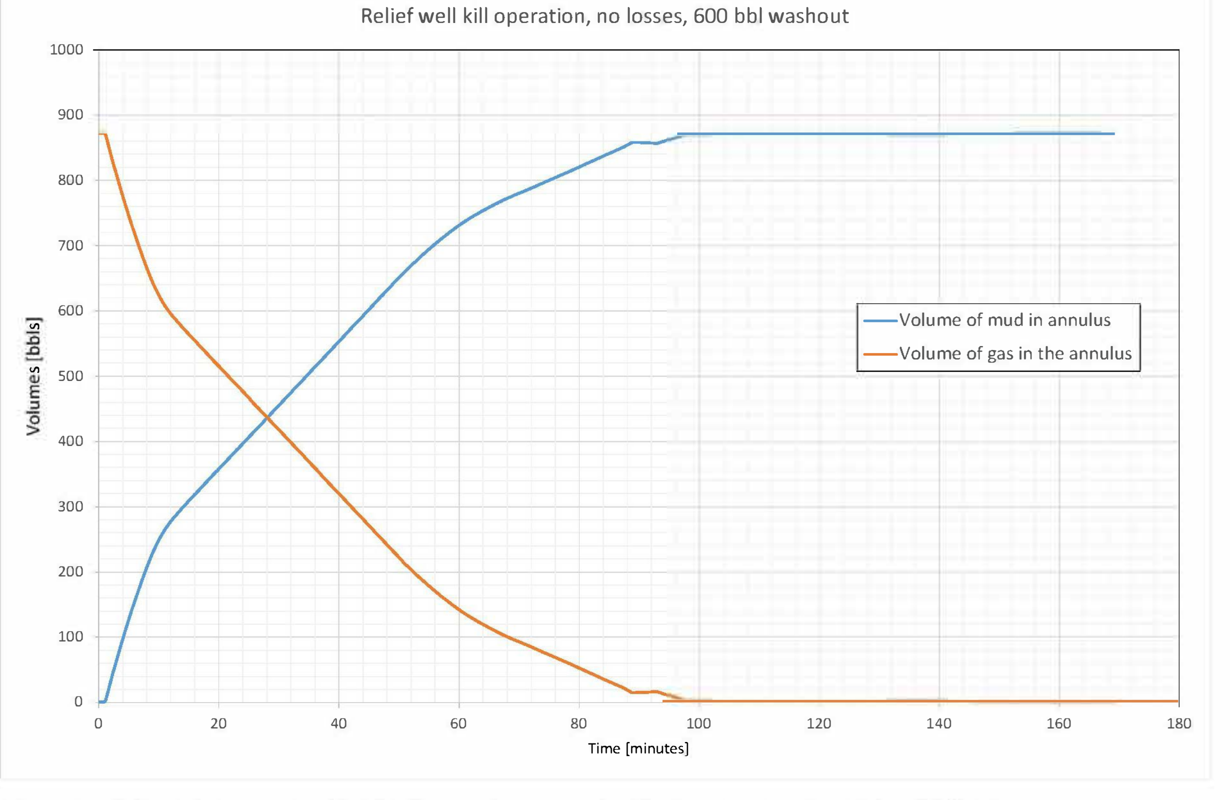

Figure B.8: Volumes, RW kill, no losses, bottom washed out to 600 bbls

8.1.3 *Relief well Kill simulations, assumed fracture zone at 8 ppg, high KH*

Simulations were performed assuming a fracture pressure of 8 ppg downhole. Hence, the formation will fracture before full returns can be achieved and leave the upper part of the wellbore, 1000 ft, filled with gas.

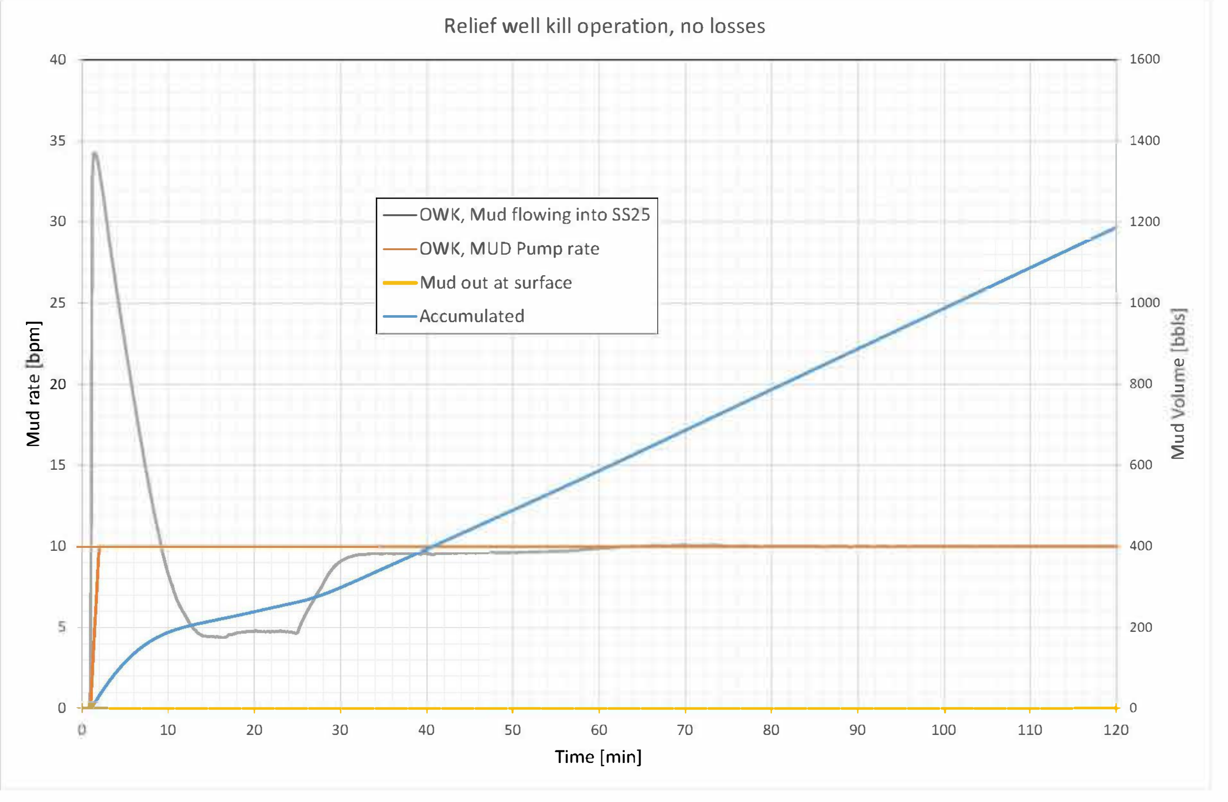

Figure B.9: Mud flow rates, RW kill, no losses, fracture gradient of 8 ppg

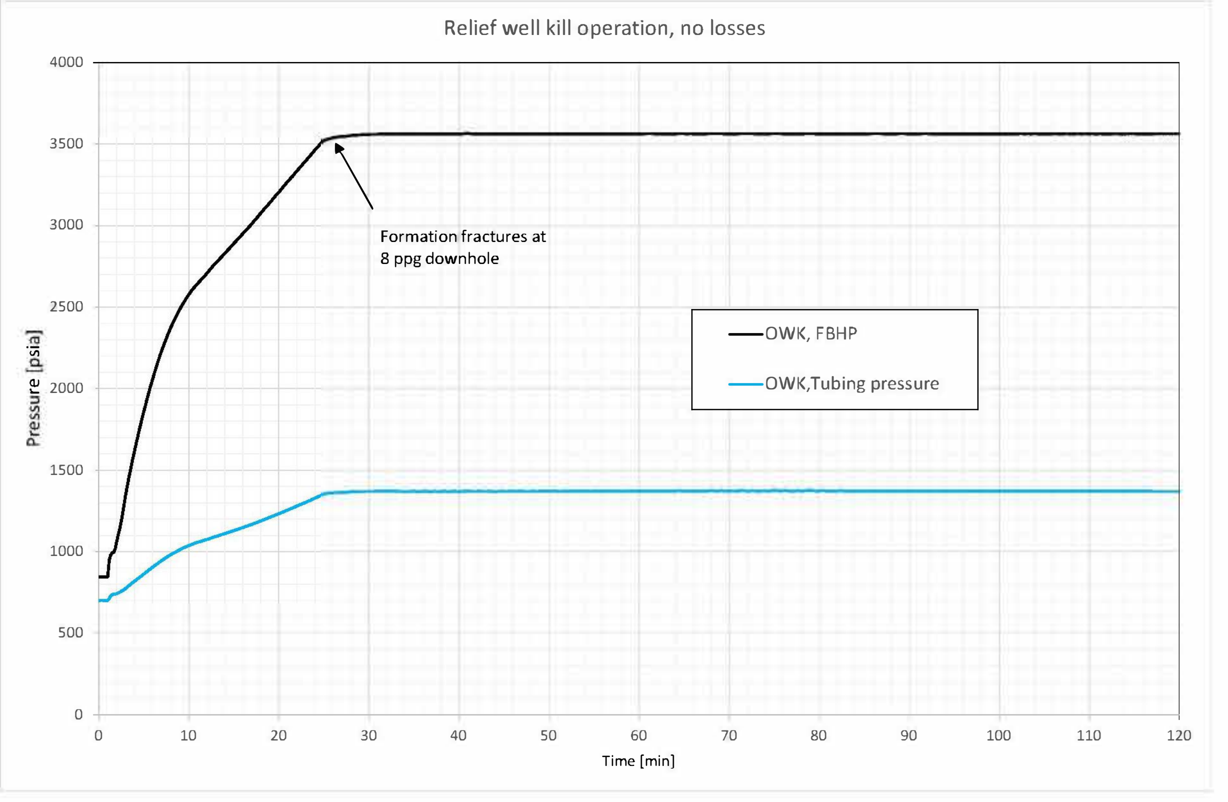

Figure B.10: Pressure response curves, RW kill, fracture gradient of 8 ppg

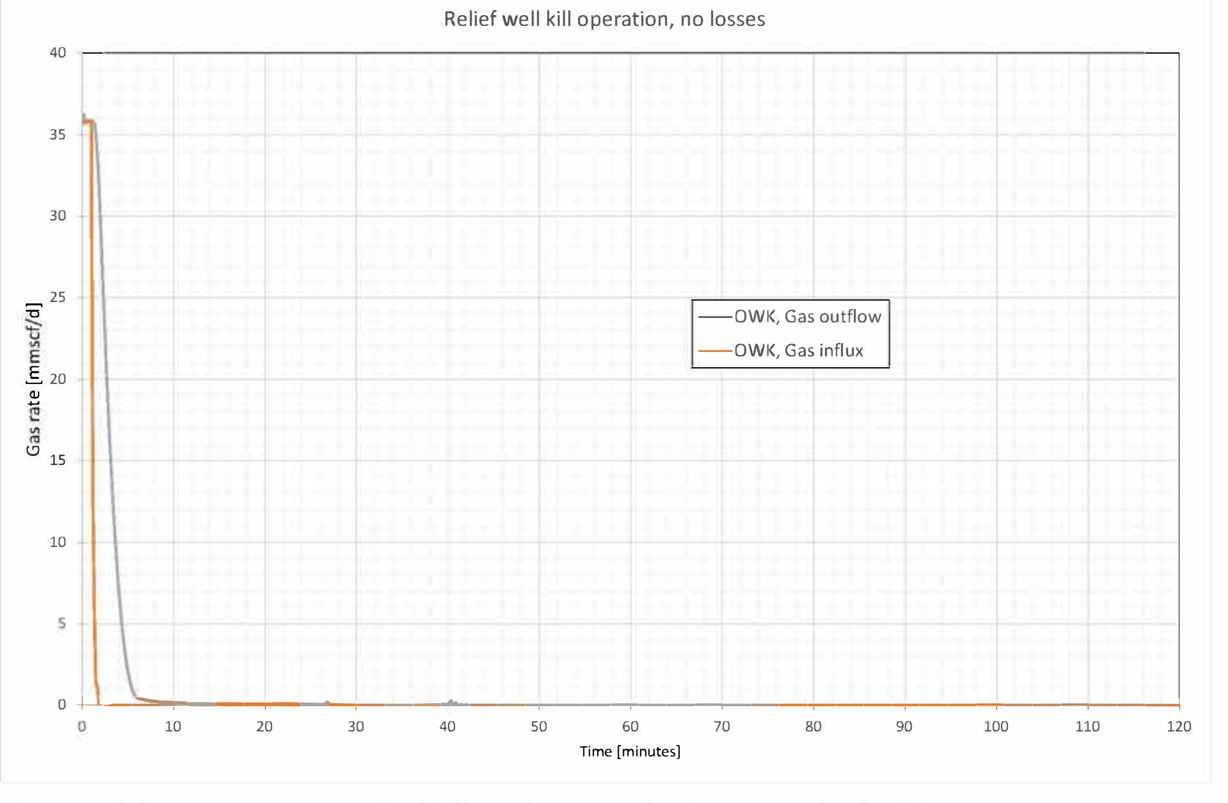

Figure B.11: Flow rates, RW kill, no losses, fracture gradient of 8 ppg

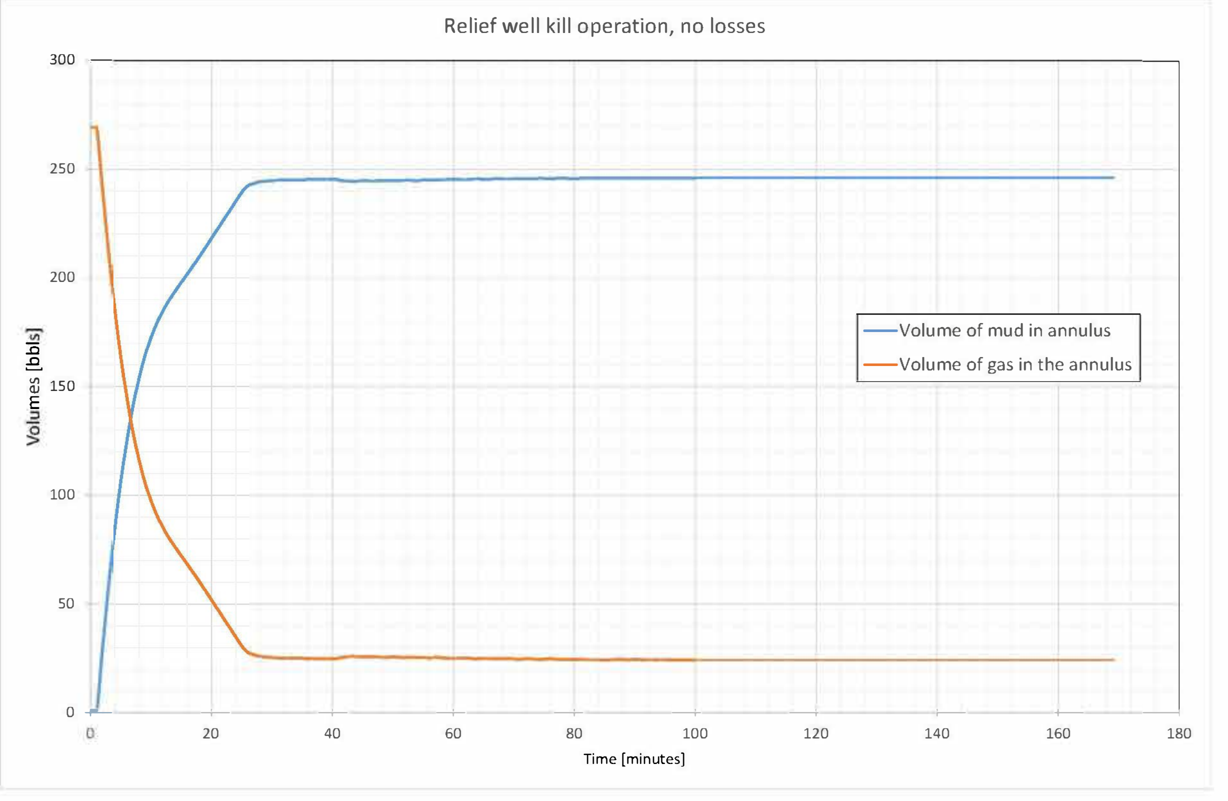

Figure B.12: Volumes, RW kill, no losses, fracture gradient of 8 ppg

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D. Software

The OLGA-WELL-KILL software is a tailor-made application for well and well control simulations and has been used in a number of on-site incidents in addition to more than 1200 studies since it was first developed in 1989.

The model has been specifically adapted to calculation of pump rates and mud volumes for a variety of blowout situations. OLGA-WELL-KILL has been developed from the state-of-the-art three-phase flow simulator OLGA from Schlumberger. It can handle numerous well flow configurations - from a single vertical well to multiple horizontal wells with complex completions. Assistance with the model is available on-site in a blowout kill planning and control situation.

OLGA-WELL-KILL has been designed for planning and evaluation of kill scenarios and intervention options. The model can be used to analyze blowout flow, kill point, pumping schedule, casing design, kill fluid properties and volumes, temperature, pressure and other related parameters. The results may be presented versus time for a complete dynamic and volumetric response.

The development of OLGA started at Institute for Energy Technology (IFE) in 1980. A major research program, in cooperation with SINTEF and sponsored by a group of large oil companies, has resulted in an industry standard dynamic three-phase code used world-wide by most operators for multiphase flow design.

After experience from a North Sea blowout in 1989, IFE sponsored by Saga Petroleum, developed a multiphase dynamic flow simulator for well kill planning. The simulator, named OLGA-WELL-KILL, was based on the dynamic two-phase flow simulator OLGA and later further developed through an R&D program. An agreement with IFE and SINTEF and later SPT Group gave add energy the rights to offer this extremely powerful tool as a service to oil companies and operators world-wide.

Well kill applications for the model include:

- Dynamic kill simulations for relief well control operations
- Top kill simulations for underground blowouts from a rig or snubbing unit
- Bull heading analysis
- Momentum kill analysis
- Shallow gas analysis

Production applications include:

- Production and injection flow characterization
- Horizontal well flow analysis
- Water alternating gas injection analysis

OLGA-WELL-KILL features that are unique to well kill applications include:

- State-of-the-art multiphase flow technology
- Advanced controller system which is representative of real pumping operations
- High pressure pump models
- Oil and gas properties fully modeled
- Pressure and temperature effects on mud properties
- Non-Newtonian flow
- Well path obstructions and leaks
- Critical flow conditions
- Various models can be used for the reservoir inflow
- User defined graphical presentation

The results from OLGA-WELL-KILL will typically provide:

- Fully dynamic simulations of the kill operation with pressures, blowout rates, pump rates, cumulative volumes, hydraulic horse power requirements and temperatures. Parameters can be displayed versus time at any point in the well(s).
- Calculation of necessary kill fluid rates, time and volumes to obtain dynamic and static kill.
- Sensitivity analysis of different kill fluids; water, brine or mud with different densities and viscosities.

The base core Olga code was presented in 1991 [ref. 14]. The original version of the OLGA-WELL-KILL model is described in a paper from 1996 [ref. 10]. Application of the model have been presented in a number of papers, see references.

PVTsim was used for fluid properties and generation of files for OLGA-WELL-KILL simulations. PVTsim is a versatile PVT simulation program developed for reservoir engineers, flow assurance specialists, PVT lab engineers and process engineers.

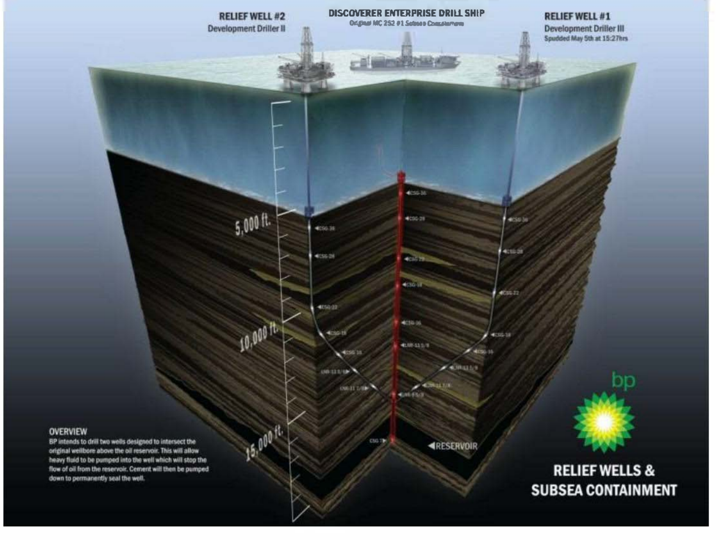
PVTsim allows reservoir engineers, flow assurance specialists and process engineers to combine reliable fluid characterization procedures with robust and efficient regression algorithms to match fluid properties and experimental data. The fluid parameters may be exported to produce high quality input data for reservoir, pipeline and process simulators.

See www.calsep.com for more info.

E. Example Cases

Based on involvement in a number of blowout intervention projects for the last two decades, **add energy** have gained a unique experience in planning and execution of blowout intervention projects. Among the many projects where **add energy** have planned and supervised the operation, the following three offshore cases have had a particular influence on well control methods and the oil industry at large.

Deepwater Horizon/Macondo blowout in GOM (2010):



While preparing to abandon a deepwater HPHT exploration well in the Macondo field in the Gulf of Mexico, oil and gas started to flow freely to the drill floor of the Deepwater Horizon drilling unit. 11 people were killed and 17 people were injured when the flow caught fire. The fire lasted for 36 hours before the rig sank to the seabed at 1500 m. The drilling riser broke and oil continued to flow at a high rate out at the seabed.

Figure B.1: Macondo blowout 2010

Key features of the well control project:

- Flow from target reservoir
- Open hole blowout with a short section of drillpipe in the upper part of the well
- Two intervention methods initiated: relief well drilling and subsea intervention
- Two relief wells drilled, one relief well drilled for dynamic kill operation, the second relief well serving as a back-up
- Kill method used: Subsea capping followed by bullheading down the production casing. The primary relief well intersected and performed final confirmation of kill and plugging with cement
- Kill rate and fluid: 5 bpm with 13.2 ppg water based mud followed by cement
- Duration from time of incident to time of kill: 87 days

add energy was providing multiphase flow modeling and well control supervision throughout the entire project and provided expert witness during the trial in 2013.

West Atlas/Montara blowout offshore Australia (2009):

Figure B.2: Montara blowout 2009

The gas condensate blowout on the Montara field in the Timor Sea occurred while starting to get in position to re-enter a batch drilled horizontal production well. The jack-up rig West Atlas was preparing to install the BOP on one of the production wells on an unmanned wellhead platform. Condensate started to flow from a thin oil reservoir layer and gas coned in from a high permeable gas cap. All personnel were safely evacuated.

Key features of the well control project:

- Flow from the target reservoir
- Open hole blowout with no drillstring or equipment in the well
- Two intervention methods evaluated: relief well drilling and surface intervention
- Surface intervention not considered safe and rejected due to high risk of explosion
- West Triton jack-up rig mobilized for relief well operation
- One relief well drilled to intersect in the horizontal section of the blowing well
- Milling operation of the reservoir casing
- Pumping operation using a combination of mud pumps and cementing unit
- No additional pumping equipment installed on the rig
- Kill rate and fluid: 67.2 bpm with 1.6 sg water based mud
- Gas flow ignited, West Atlas burned down, wellhead platform partly damaged
- Duration from time of incident to time of kill: 74 days

add energy was providing multiphase flow modeling and well control supervision throughout the entire project.

Elgin Gas Blowout in the North Sea (2012):

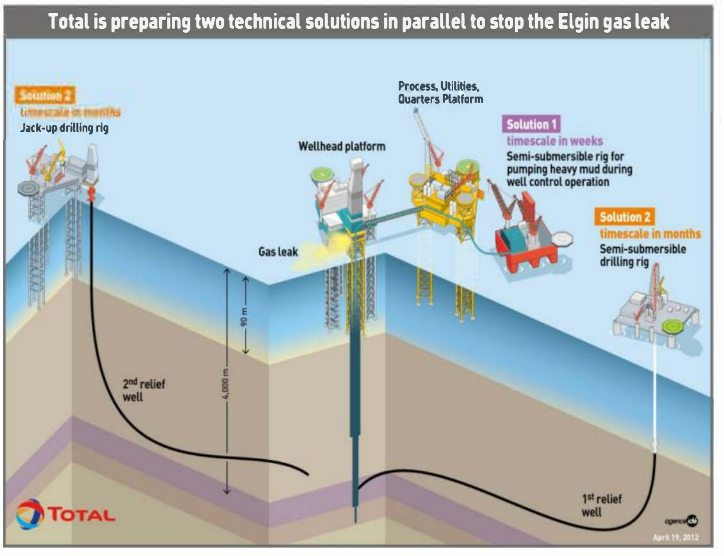


Figure B.3: Elgin blowout 2012

The blowout occurred during P&A of a HPHT production well on the Elgin wellhead platform in the UK sector of the North Sea. The well flowed gas and condensate to the platform deck due to mechanical failure of all casing strings after pressure build-up. A successful surface intervention followed by dynamic kill was possible due to low flow rate of gas and condensate. All personnel safely evacuated.

Key features of the well control project:

- Annulus blowout with leak paths through several annuli
- Flow from a charged reservoir zone above the main target expected to be charged by the production zone over years
- Two intervention methods initiated: relief well drilling and surface intervention
- Two relief wells planned: one from a semi-submersible rig and one from a jack-up rig. One of the relief wells spudded and drilled in parallel with the attempting surface intervention
- A relief well intersection had an expected lead time of more than 5 months
- Kill method used: Surface intervention with dynamic kill down existing production tubing
- Kill rate and fluid: 10 bpm with 2.05 sg water based mud
- Pumping operation performed from the West Phoenix DP rig in position alongside the platform connected with coflex hose
- Gas flow not ignited. Re-boarding of platform possible due to low gas rate.
- Duration from time of incident to time of kill: 51 days

add energy was providing multiphase flow modeling and well control supervision throughout the entire project.