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Ultra-Deepwater Blowout Well Control and Abandonment Operations Through Relief Well Under Capping and Containment Scenario After Worst Case Discharge

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Abstract

For ultra-deepwater wells, the ability to control and plug the blowout well is more and more important as regulatory agency has more strict rules to issue a drill permit. After the blowout well is killed, cement plugs need to be placed in the borehole to prevent migration of fluids between the different formations. Because of the mixing and contamination process of the cement slurry pumping through relief well, to ensure required cement height and good quality for blowout well, is more challenging than the topside intervention well plugging operations.

In this study, dynamic simulations are carried out to assess the difficulties faced during blowout well control and abandonment. In the selected scenarios, the capping stack system is installed on the wellhead of the blowout well and three vessels are used to capture the oil with risers connected to each vessel separately. Through the relief well, sea water is pumped to the blowout well, increasing the hydrostatic pressure and reducing the rate of production. The injection of sea water together with the manipulation of choke outlet pressures on the vessels provides proper conditions for controlling the blowout well, keeping the liquid flow rates within the limits imposed by the processing capacity at surface. As sea water accumulates in the blowout well, reducing oil production rate, each vessel is shut down accordingly. Once the blowout well is completely filled up with sea water, kill mud is used to replace sea water to ensure static kill. Cement slurry is then pumped to blowout well to set the cement plug. The displacement is specially studied when the cement slurry is flowing into the blowout well. In the sensitivity analysis, borehole enlargement, cement slurry rheology, and flow rate are considered to investigate the contamination of the cement slurry.

The presented outcomes allow engineers to better understand the operation procedures for blowout well control with capping, containment and zero discharge to the environment under capping and containment scenario after worst case discharge, and the methods to mitigate cement slurry contamination and ensure good cement plug for well abandonment.

Introduction

As the uncontrolled production of hydrocarbons from a well is, certainly, one of the most serious incidents can happen within the operational context of the oil and gas industry, the best approach consists of formulating well contingency plans to prescribe adequate emergency responses to possible blowouts in advance of spudding. For ultra-deep water wells, formulating a well contingency plan is crucial because the efforts to regain control over the well are more complex and expensive than for any other scenarios. As a consequence, the industry has introduced the idea of being effectively prepared to deal with the worst case discharge scenario, above all, in deep and ultra-deep waters. It is so important that literature presents a significant number of studies focusing on different aspects, such as the calculation of the worst case discharge rate (Liu et al., 2015), its effects on casing design (Bowman, 2012; Wu, 2013), and the potential leak paths to surface after the well is capped (Zaki et al., 2015). In 2006, Lage et al. assessed the risk and hazard of blowout rate calculations and relief well planning. Besides, Yuan et al. (2014) analyzed the strategies to ensure wellbore integrity to control the blowout well under worst case discharge event.

The present scenario differs significantly from the one usually adopted to study subsea blowouts, which is characterized by a subsea well discharging to the bottom of the sea. The produced fluids rise and flow to the surface of the sea, forming an upside down cone from bottom to surface (see Fig.1). In addition, the upward movement of hydrocarbons induces seawater motion, producing streams. For this situation, as chokes are not available to control the subsea blowout well, the killing procedure demands for injecting seawater or drilling fluid with high rates. In addition, as possible horizontal sections are in deeper portions of the well, free gas does not appear, meaning that there is no two-phase or multiphase mixture flowing through horizontal tubular or annular geometries. In other words, two-phase, liquid and gas, or multiphase flow, different types of liquids and gas, occurs only through the upper portion of the well, which is a vertical or slightly inclined section.

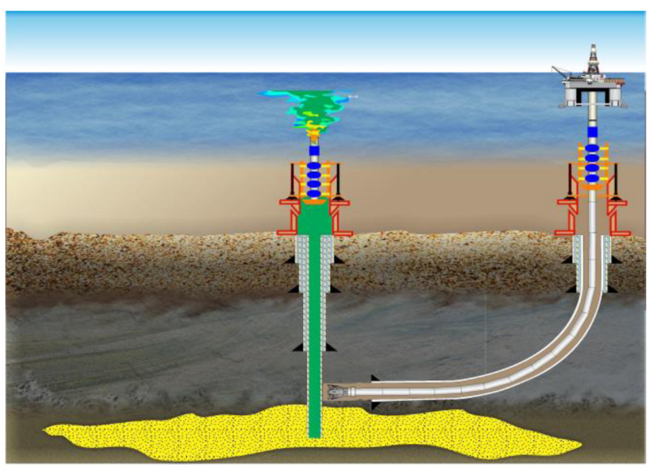

Figure 1—Usual scenario for blowouts in subsea wells

Under the condition that the blowout well is capped with the containment system collecting all fluids produced (see Fig. 2), the present study focuses on the development of an operational sequence to kill and abandon it. Besides that, improvement opportunities are identified based on the evaluation of the present scenario. In this study, two main assumptions are adopted: (1) the containment system collects the whole production from the blowout well. In other words, discharges to the environment are not tolerated; and (2) the relief well is hydraulically connected to the blowout well at the pre-defined interception point. It is worth to mention that operational difficulties related to achieving the interception between those two wells are out of the scope of the present study.

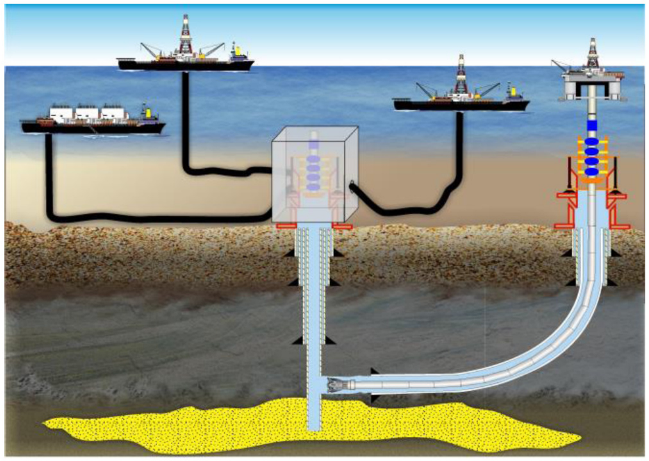

Figure 2—Present scenario with capping and containment

Subsea chokes from the capping stack and chokes at surface, which are upstream the processing plants, are available to assist well control and split the produced fluids to the plants at surface in accordance to their capacities. However, as the zero discharge philosophy is adopted, the chokes at surface are used instead of the ones from the capping system. Regarding twophase or multiphase flow, they are likely to occur through the containment components, consisting of horizontal flexible lines and vertical risers.

In principle, well killing operational procedures are composed of: (1) a programed sequence of fluids to be pumped through the relief well to reach the blowout well with controlled injection rates; (2) a set of rules to guide the process of maneuvering the three distinct surface chokes, each one located upstream to a processing plant; (3) a set of parameters to be monitored, helping to secure that the control process evolves properly and (4) a set of contingency procedures considering equipment and human failure.

However, as controlling the three surface chokes simultaneously is a difficult task, demanding exceptional level of communication among involved personnel, the adopted strategy to make it simpler consists of reducing as quick as possible the produced flow from the blowout well and closing the processing plants in sequence, accordingly to the production reduction. The idea is to reach rapidly a situation in which only one processing plant is in use, meaning that only one surface choke is used to control.

After reaching the control stage and filling the whole system with drilling fluid with hydrostatic capacity to stay overbalance, a cement plug is mixed and displaced to the blowout well, providing condition for, at least, temporary abandonment.

Target well description

As shown in Fig. 3, this is a hypothetical vertical well with water depth of 2218 m (7277 ft). The approximated reservoir properties assumed are: Gas oil ratio of 2500 scf/bbl; Productivity index 44 bbl/day/psi; Reservoir pressure 9200 psia; Reservoir top depth: 4990 TVD m. Fig. 4 shows that three vessels are connected to the wellhead by risers and sea bed flow lines. Vessel 1, 2, 3 are designed respectively to process 14000 STB/day, 8700 STB/day and 8700 STB/day of oil capacity. For vessel 2 and 3, the length of sea bed flow line between the wellhead and riser bottom is 2050 m, however, for vessel 1, it is 1450m. The flow line ID and riser ID are 6″ and 5.5″ respectively. Before the interception of the blowout well, the oil production rates for vessel 1, 2, 3 are 13607 STB/day, 8450 STB/day, and 8450 STB/day respectively. The gas production rates for vessel 1, 2, 3 are 33.8 MMscf/day, 21.0 MMscf/day, and 21.0 MMscf/day respectively.

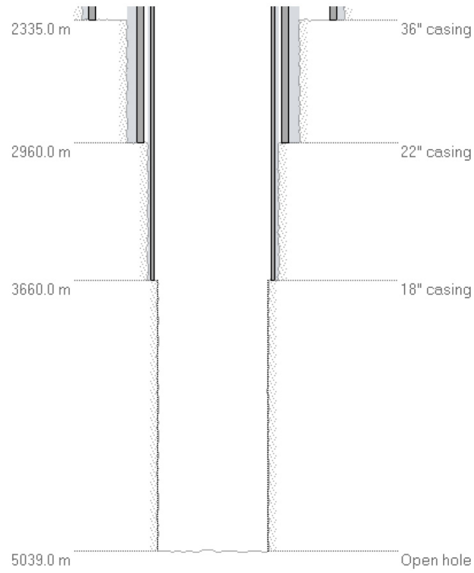

Figure 3—Blowout wellbore geometry

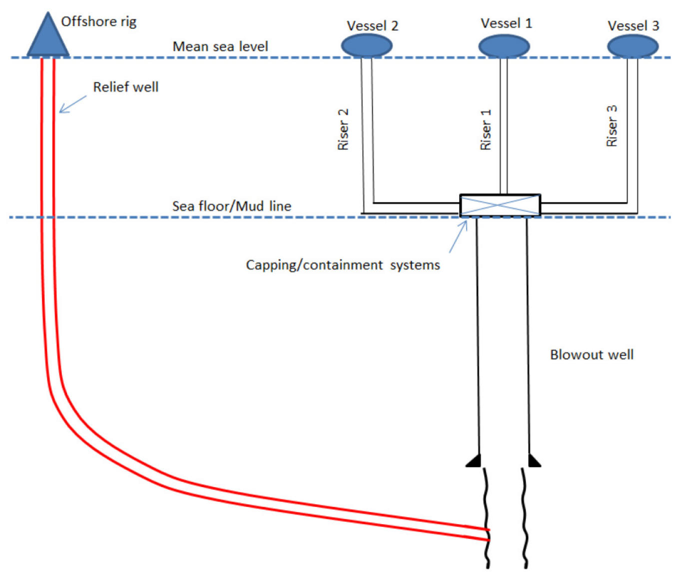

Figure 4—Blowout and relief well configurations

Relief well description

The intersection point is designed to be 4987 m TVD, which is at the reservoir top. Last 9 5/8″ casing is set at 5025 m MD. Relief well openhole size is 8.5″ and the length is 50 m. The bit is 15 m above the intersection point. Before intersection, relief well is filled up with 10.9 ppg water based mud.

For the present scenario, the killing operation demands dealing with a certain number of challenges, such as: (1) a narrow operational window, established by pore pressure, 9234 psia, at the top of the reservoir and fracture at casing shoe, 7600 psia, at 3650 m; (2) the long openhole section, 1327 m, in the relief well; (3) limited processing capacity at surface, vessel 1: 14000 STB/day (408 gpm), vessel 2: 8700 STB/day (254 gpm) and vessel 3: 8700 STB/day (254 gpm); (4) before starting the killing operation, the production steady state to the containment system in place was achieved with high surface pressure (at about 3200 psia), operating close to the maximum processing capacity; (5) as a premise, discharges to the environment are not tolerated.

Considering all those aspects, the dynamic multiphase flow software OLGA® is used as the fundamental tool to carry out the simulations.

Pump rate optimization to mitigate free-fall

When both relief and blowout wells are connected, as the relief well is drilled with 10.9 lbm/gal drilling fluid, its pressure at the interception point is higher than the one at the same point in the blowout well. As a consequence of this pressure imbalance, the drilling fluid flows automatically into the blowout well. If the flow rate into the blowout well is higher than the pumping rate, there is no pressure seen on the pump due to the void created at the top of the relief well. This phenomenon is well known as “free-fall” effect, happening just after having both wells hydraulically connected.

Five cases were simulated varying different pump flow rates, by injecting through the drillstring and through the kill and choke lines (relief well), to assess free-fall and back flow into the relief well. Table 1 shows the maximum depth for free-fall and how long it takes to disappear. Even with 320 gpm pump rate, there is still 20 minutes of free-fall.

Table 1—Free fall results

Pump rate		Drillstring		Kill and choke lines	
Drillstring (gpm)	Kill and choke lines (gpm)	Free-fall max depth (m)	Time (minutes)	Free-fall max depth (m)	Time (minutes)
200	160	139	14	386	44
200	170	139	14	386	42
200	320	139	12	288	22
400	160	No free fall	No free fall	386	36
400	320	No free fall	No free fall	288	20

Regarding back flow into the relief well, some simulations are also carried out to detect its occurrence. It is observed that 50 gpm is the smallest pump rate through relief well to avoid back flow. As a summary of the conclusions after performing this set of simulations, the pump rate of 400 gpm for drillstring and 320 gpm for relief well kill line are used for the initial pump rate during the blowout well control.

Decision workflow

The simulation task is planned previously to be concluded after studying two or three different scenarios. However, following the philosophy of reaching rapidly a situation in which only one surface choke and only one processing plant are used to control leads to the occurrence of severe slugging (SS), which is better explained by the sequence from Fig. 5 to Fig. 8.

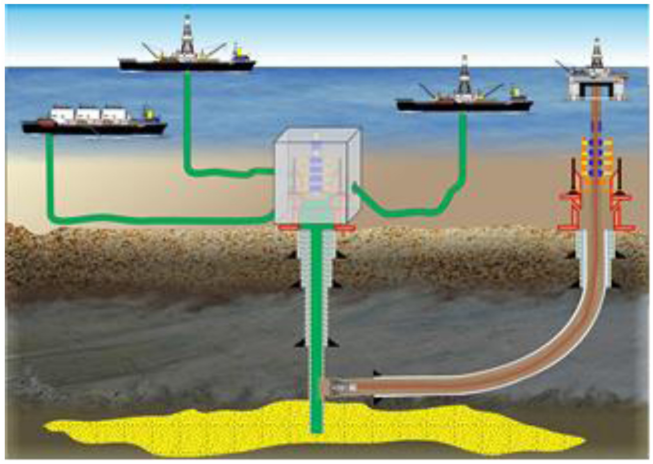

Figure 5—Relief Well is connected to the Blowout Well

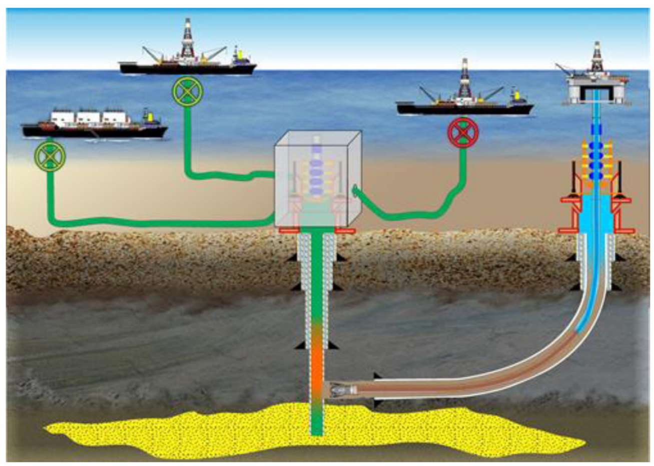

Figure 6—One leg is closed with the mud mixed to produced fluids

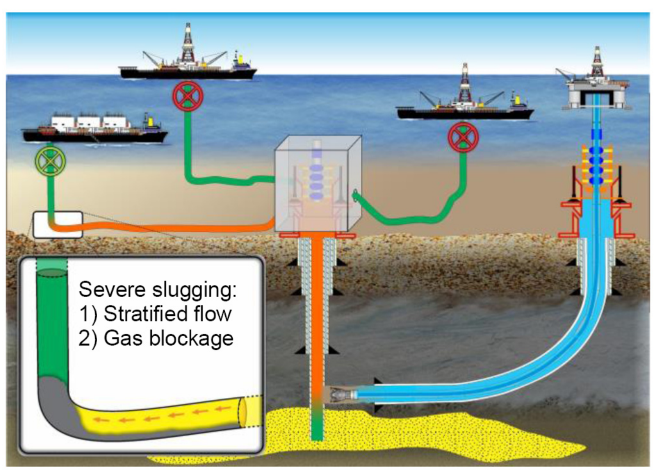

Figure 7—Two legs closed and gas blockage at the base of the riser

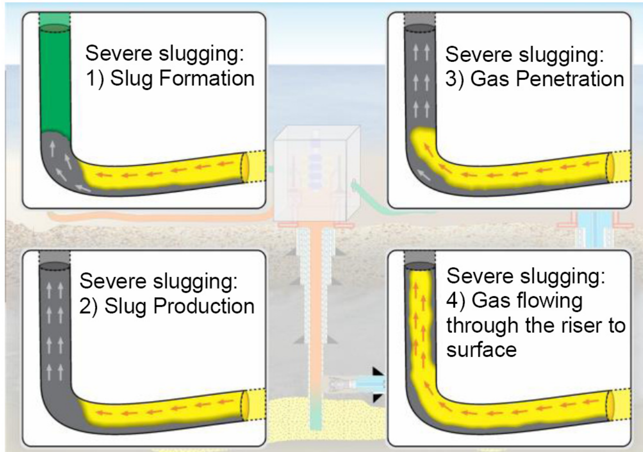

Figure 8—SS stages

Regarding the Figures, from Fig. 5 to Fig. 8, the green color is associated to the mixture of produced fluids from the reservoir, the brown color is the drilling fluid and the blue color represents seawater. Further, the orange color represents the mixture between the drilling fluid and the produced fluids from the reservoir, which is mixed in the blowout well. However, as the orange mixture of fluids flows into the flexible line, see Fig. 7, the flow pattern gains more relevance, demanding a much more detail view. As represented in Fig. 7, the flow through the horizontal flexible line leads to a kind of stratified flow condition, in which, the liquid, a mixture of drilling fluid and oil from the reservoir is represented by the gray color and flows through the lower part of the duct. The yellow color represents the gas flowing through the upper part of the duct. Flowing through the riser, the liquid mixture, drilling fluid and reservoir oil, represented by the gray color, blocks the gas in the flexible line. The upper part of the riser contains a mixture of oil and gas from the reservoir, which is painted green.

The condition for maintaining the gas blockage is described by Eq. (1):

$$\frac{dp_r}{dt} > \frac{dp_d}{dt} \tag{1}$$

From the occurrence of the gas blockage, the growth of hydrostatic pressure in the riser must be faster than the increase in pressure in the flexible line, maintaining the gas trapped. In fact, this is the Bøe (1981) criterion, which is a simple and conservative mathematical expression, which leads to the following equation:

$$v_{sl} \geq \frac{p_d}{\Delta\rho_l g \alpha L} v_{sg} \tag{2}$$

where p_d denotes the pressure at the base of the riser at the moment gas blockage occurs, $\Delta\rho_l$ is the difference of density between the mixture of drilling fluid and oil from the reservoir, 1100 kg/m^3 (9.2 lbm/gal), and the produced oil reaching the surface separation plant, 820 kg/m^3 (6.8 lbm/gal), α is the average void fraction in the flexible line, L is the length of the line, v_{sl} and v_{sg} are, respectively, the superficial velocity of liquid and gas. Eq. (2) is presented in Fig. 9, where it appears as the Bøe criterion line. In addition, the black square represents the operational condition when the phenomenon is observed while performing the computer simulations and the green line represents the limit for stratified flow through the flexible line.

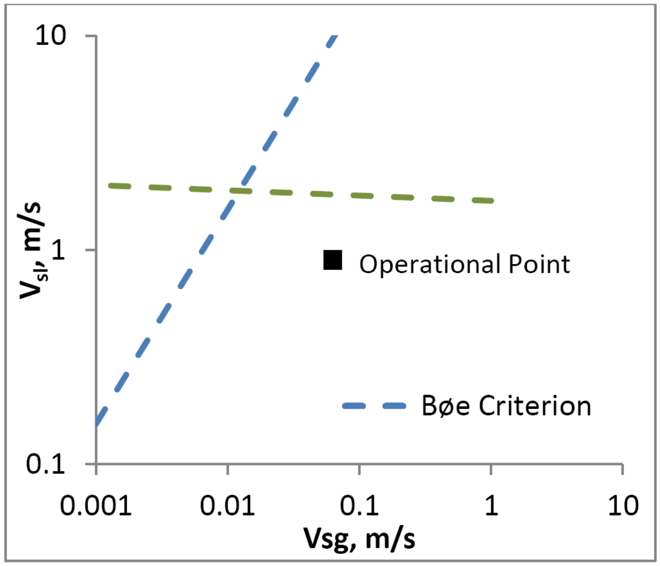

Figure 9—Severe slugging map for scenario 2

Despite not being above the Bøe line, it is well known that the phenomenon of SS can also appear in a much bigger area in the map (Luo et al., 2011).

Many scenarios are considered in the process to find a way to mitigate slugging issues in well control process as shown in Fig. 10. The phenomenon occurs once the high density liquid mixture composed of high viscosity drilling fluid and produced oil flows through the sea floor flow lines and reaches the base of the riser. The adopted approach for mitigating the slugging issues is based on diluting drilling fluid, which reduces its density and viscosity. Two possibilities are accessible: (1) keeping or even stimulating the oil production while having the drilling fluid flowing through the blowout well; (2) sea water injection from the wellhead through lines which are available for injecting chemicals while having the drilling fluid flowing through the horizontal flexible lines. In other words, for diluting the drilling fluid with the produced oil, killing the blowout well is postponed for a certain period during the controlling process. Then, after having the drilling fluid diluted, seawater injection rate from the relief well is increased to kill the blowout well.

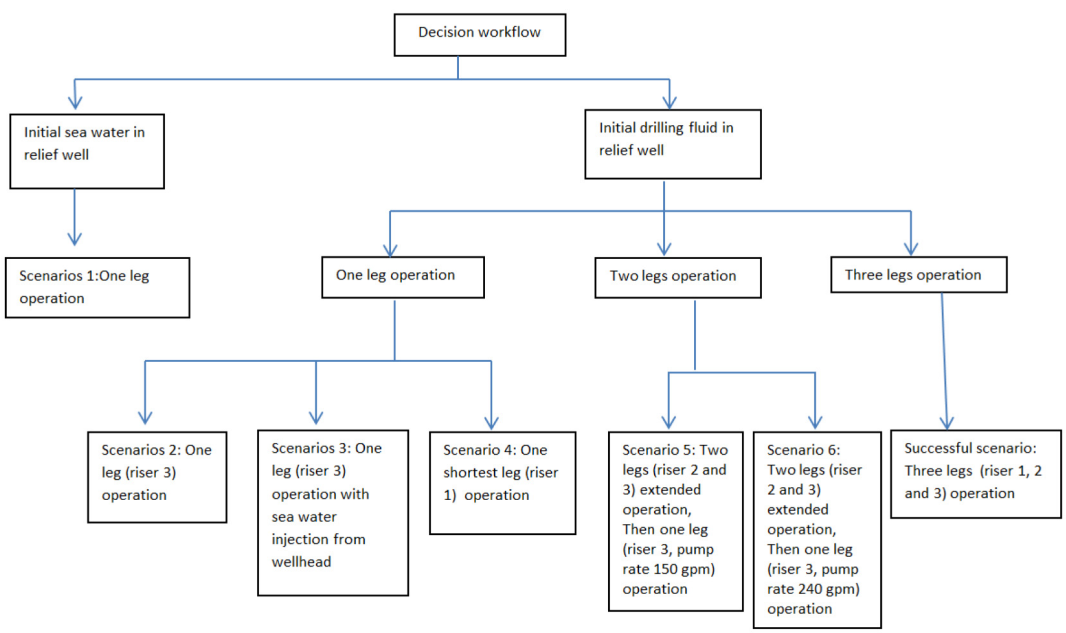

Figure 10—Decision Workflow

Scenario 1: if the relief well is initially filled with sea water, no SS issues will be observed during the well control process. However, in reality, the relief well should be initially filled up with high density high viscosity drilling fluid. This scenario is only simulated to help investigating free-fall and flow back effects.

Scenario 2: SS issues are observed once drilling fluid mixture occupies the sea floor flow lines. Because of the sudden high flowrate arriving at surface and the high peak of pressure generated by the SS phenomenon, the wellbore can be fractured below the casing shoe and the surface facility has to manage an abrupt condition in which liquid and gas rates coming from the well are much higher than the capacity of the plant.

Scenario 3: Sea water injection from the wellhead reduces the peaks but is not enough to mitigate the SS issues. The casing shoe and surface facility can still be facing an unfavorable scenario during the well control process.

Scenario 4: Using the shortest leg (riser 1) reduced the peaks but is not enough either.

Scenario 5: Using two legs to extend the period of production from the blowout well dilutes a bit more the drilling fluid and mitigates the slugging issues. Once the drilling fluid is diluted, the decision is made to produce through only one leg (riser 3). Because of the high reservoir pressure and lower mixture density between the reservoir top and casing shoe, it is necessary to reopen all legs (riser 1, 2 and 3) to avoid casing shoe fracture and restart the killing process, this time, with the whole system with just water, oil and gas.

Scenario 6: Since the drilling fluid dilution in scenario 5 leads to reopening 3 legs, it is tried to reduce the drilling fluid dilution, increasing the mixture density and keeping just one leg open in the final phase of the process. However, the SS issues occur due to the higher density mixture and the lower flow rates.

Successful scenario: The final decision is made to keep producing with the highest possible rates at surface through the three risers. The computer simulation confirms that this solution can effectively mitigate the consequences of SS.

Severe slugging issues for Scenarios 2

For this scenario, the following control procedure is proposed: at the moment the relief well is connected with the blowout well, the seawater pumping is started. When the total production rate is lower than 20000 STB/day, the second leg (vessel 2) is closed. After that, when the total production drops to 6000 STB/day, the first leg is closed. The third leg is always kept open. The shut-in procedure for each leg is to close the valve near wellhead first, and then close the surface choke. Sea water is pumped 400 gpm through the drillstring until it is filled with 100% sea water. Simultaneously, through the kill and choke line, sea water is pumped 320 gpm during the whole operation.

After closing the second leg (riser 2) and keeping production through leg 3 (riser 3), SS happens in the horizontal branches of leg 3 which is shown in Fig. 11. When the gas penetrates into the riser (see Fig. 8), not only a huge amount of liquid arrives at the rig, exceeding the capacity of the plant, but also the pressure at casing shoe goes higher than the fracture pressure, threatening the integrity of the wellbore which is shown in Fig. 12. After analysis, it is concluded that the phenomena starts when the liquid mixture composed of high viscosity drilling fluid, from the relief well, and produced oil arrives at the base of the riser. One additional scenario is simulated reducing the pump rate to 40 gpm. Even at this rate, SS still occurs. From the operations side, there is a risk using pump rate less than 50 gpm. There is no effective way to mitigate the SS with pump rate higher than 40 gpm. Fig. 13 and Fig. 14 show the liquid density and void fraction profiles just before SS occurs.

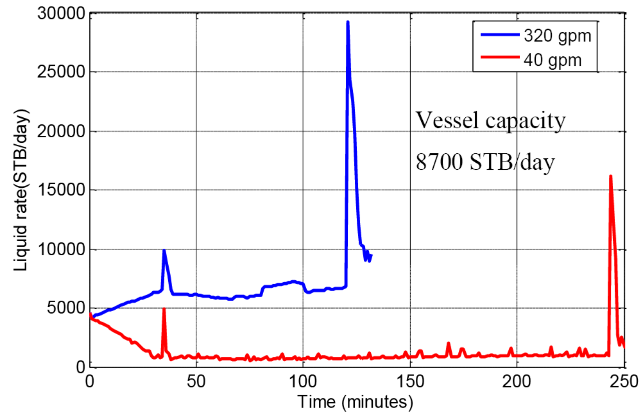

Figure 11—SS for Scenario 2: Liquid rate at surface

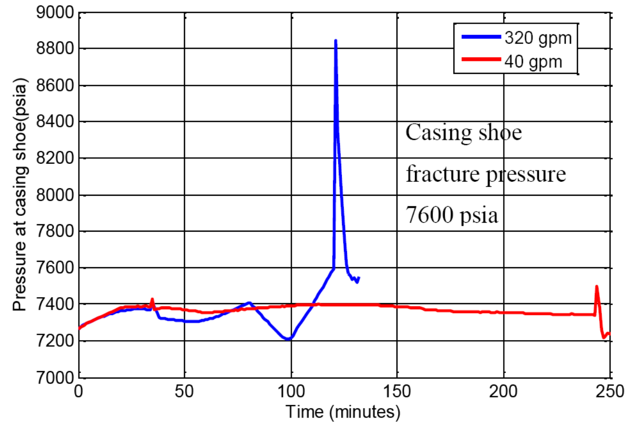

Figure 12—SS for Scenario 2: Pressure at Casing Shoe

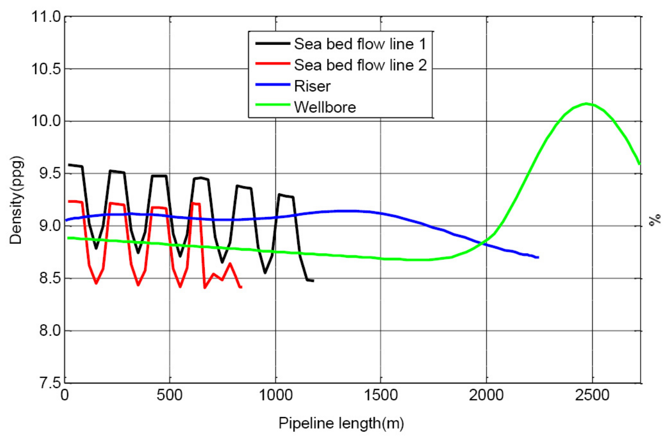

Figure 13—Density Profile before the flowrate peak (320 gpm)

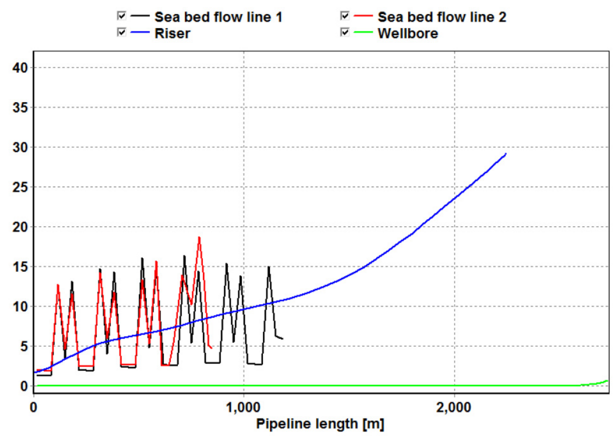

Figure 14—Void fraction profiles before the flowrate peak (320 gpm)

Scenarios 3, 4 and 5 have similar SS issues as scenario 2.

Three legs operation with initial drilling fluid in the relief well

In this scenario, the relief well is initially filled up with 10.9 ppg (1309 kg/m^3) drilling fluid. The blowout well and relief well are connected 8 minutes after starting the simulation. Fig. 15 and Fig. 16 show that at the moment of connection, the surface liquid and gas production rate suddenly go up. The peak lasts for 8 minutes. Fig. 15, Fig. 16 and Fig. 20 show that the liquid and gas production rates also change based on the injection rate variations from the relief well. In Fig. 15, Fig. 16 and Fig. 17, the parameters from vessel 2 almost overlap those from vessel 3. Fig. 20 shows the adopted injection rates through the kill line from the relief well for the control operation. When the total amount of drilling fluid in the relief well is displaced into the blowout well and diluted with reservoir fluids, pump rate was increased from 320 gpm to 1000 gpm to stop the reservoir flow as fast as possible. Once the reservoir flow stops, the pump rate is reduced to 700 gpm to ensure that the operation stays within the limits of the surface vessels capacity.

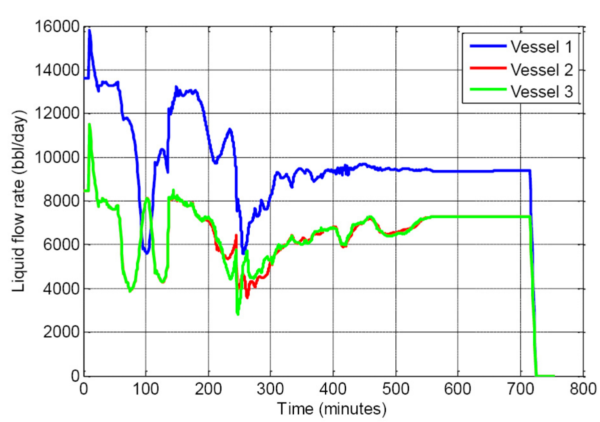

Figure 15—Liquid Production Rate at Surface

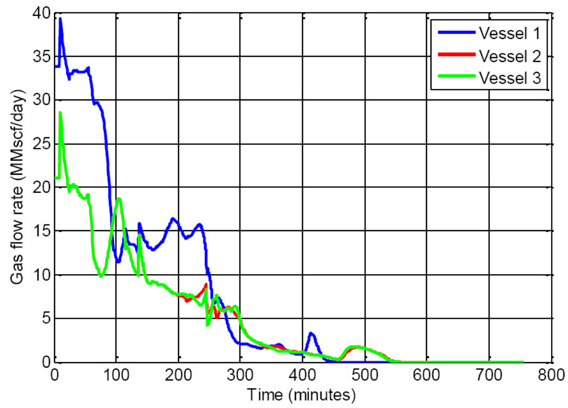

Figure 16—Gas Production Rate at Surface

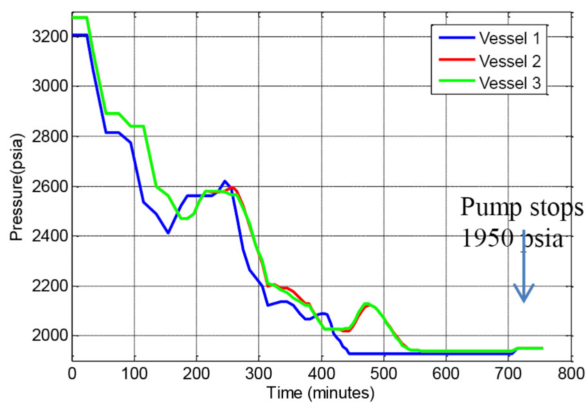

Figure 17—Choke pressure at Surface

In the well control process, the wellbore integrity can be ensured as shown in Fig. 18. The safety margin at the casing shoe is higher than 200 psi. As shown in Fig. 16, once surface gas production rate reduced to zero, the pump is kept running for more than 150 minutes to clean the oil and gas in the sea bed flowlines. The volume of the sea water pumped during 150 minutes is equal to the volume of all the sea bed flowlines and risers. When pumps stop, oil and gas is completely removed from the blowout well.

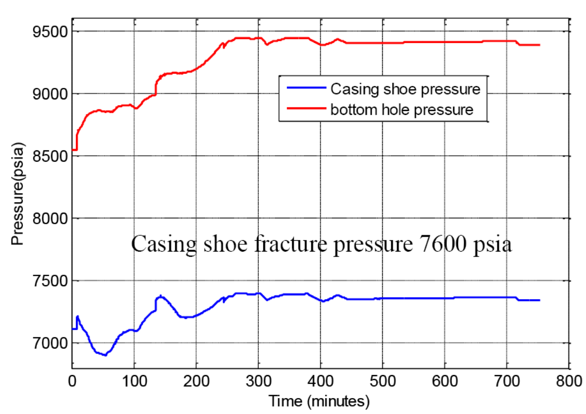

Figure 18—Pressure at Bottomhole and Casing Shoe

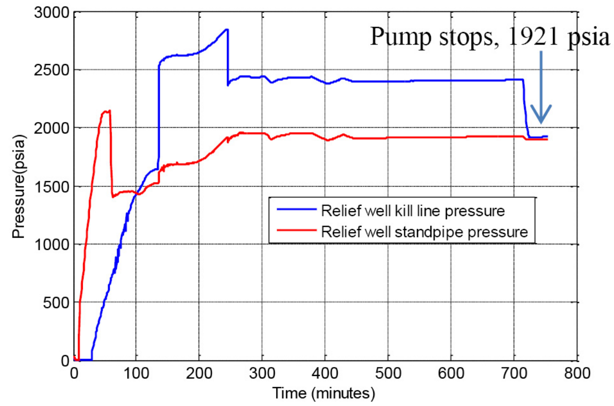

Figure 19—Stand Pipe and Kill Line Pressure from the Relief Well

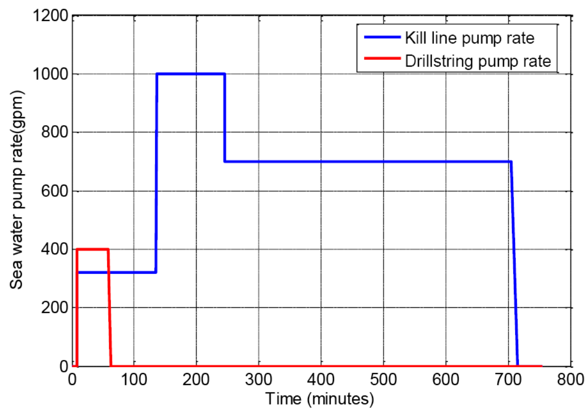

Figure 20—Injection rates from the Relief Well

After stop pumping, the blowout well surface pressure is maintained at 1950 psia which is shown in Fig. 17. The well is overbalanced 170 psi and safety margin for the casing shoe is 200 psi. From the perspective of the relief well, the kill line and standpipe pressure are 1921 psia as shown in Fig. 18. After pumps stop, the 30 psi difference between the relief well surface pressure and blowout well surface pressure is because of the density variance in the relief well and blowout well due to the temperature difference.

In reality, the challenge for the three legs operation is how to effectively coordinate the operations from the three vessels and relief well simultaneously. The coordinating strategy needs to be defined.

Cementing Operations

To permanently abandon the blowout well, Al-Murri et al. (2012) and Varela et al. (2015) pumped cement slurry to the target well from the relief well. For this study, a similar process is considered. After the blowout well is killed and filled up with 10.9 ppg fluid, cement slurry is mixed (see Fig. 21) and displaced into the target well, setting a cement plug. The volume of the cement is equal to the volume of 500 m target well openhole section plus the volume of the relief well openhole section. The volume of the spacer is equal to the volume of 500 m blowout openhole section. Fluid properties for cement slurry and space are shown in Table 2. Before pumping cement slurry, relief well drillstring is replaced with a single pipe with ID 4.67″ and OD 5.5″. The lowest extremity of the drillstring is set at the casing shoe.

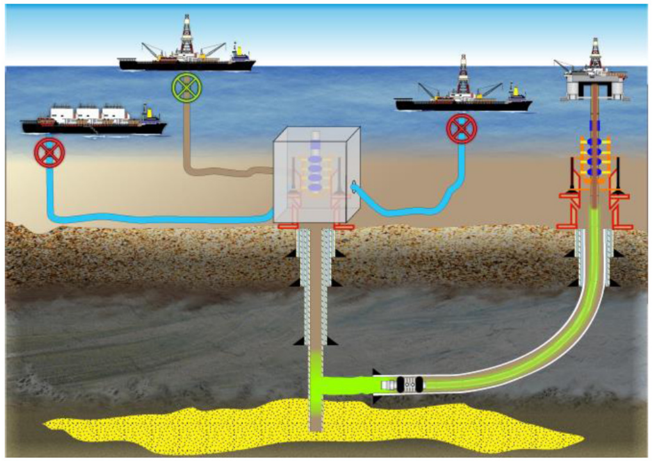

Figure 21—Cement slurry is mixed and injected into the drillstring

Table 2—Fluid properties

			Fann data (lbf/100ft^2)						
Fluid	Density (ppg)	Volumes (bbl)	300 rpm	200 rpm	100 rpm	60 rpm	30 rpm	6 rpm	3 rpm
Spacer	11.9	408	52	46	33	28	22	14	11
Cement	15.8	417	271	204	121	81	34	13	9

For the target well, two cases are considered, 0% wellbore enlargement (normal wellbore) and 20% wellbore volume enlargement. Pump speed for mixing cement slurry is 3 bpm. Pump speed for mud to displace cement slurry is 12 bpm.

Results of cementing operations

Since the casing shoe fracture pressure is 7600 psia, the target wellbore integrity can be ensure as shown in Fig. 22. From Fig. 23, after the cement slurry is displaced, the surface back pressures on relief well to balance the system are 413 psia for 0% wellbore enlargement and 261 psia for 20% wellbore volume enlargement. Fig. 24, Fig. 25 and Fig. 26 present the frictional pressure drop at different pump rates for each well section. As shown in Fig. 27, at least, 250 m of good cement is obtained for zero percent wellbore enlargements and 150 m good cement for 20% of wellbore volume enlargement.

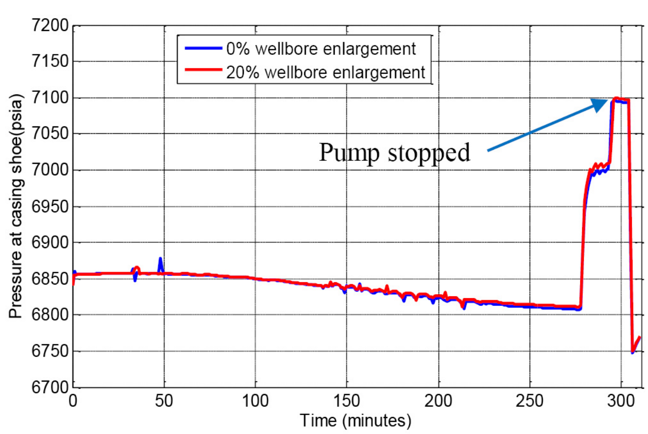

Figure 22—Casing Shoe Pressure during Cement Operation

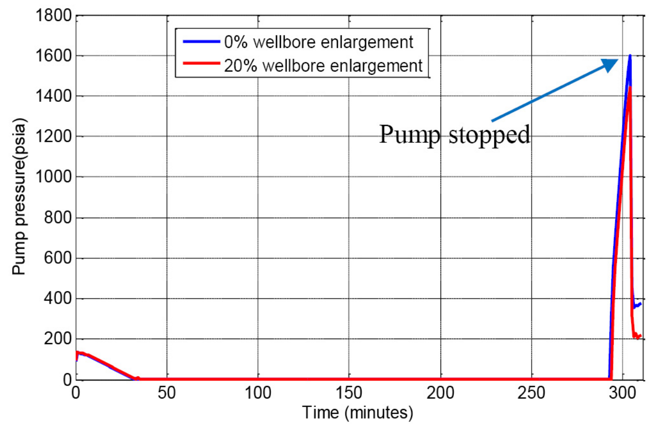

Figure 23—Pump Pressure during Cement Operation

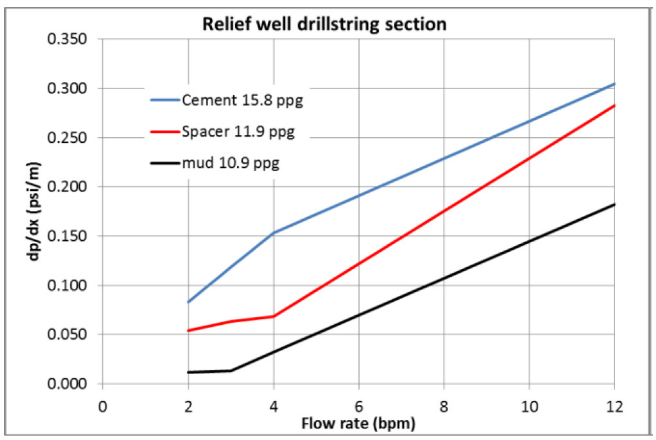

Figure 24—Relief Well Drillstring – Frictional Pressure Drop

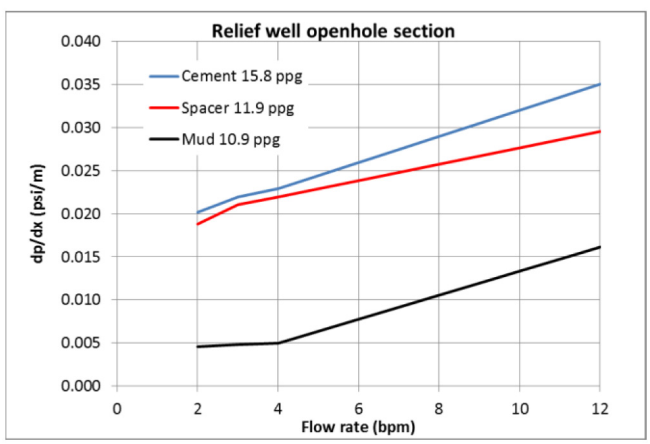

Figure 25—Relief Well Openhole – Frictional Pressure Drop

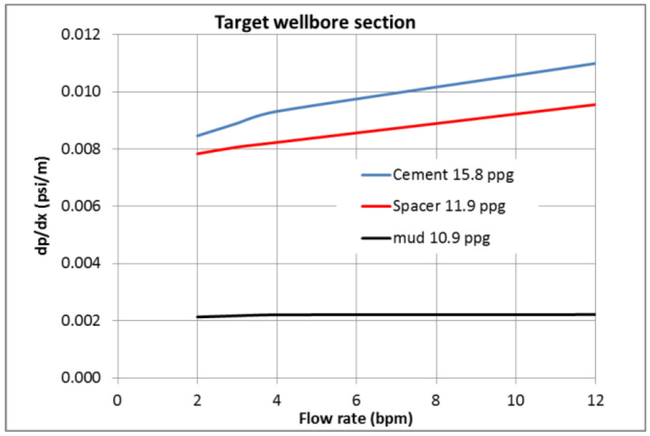

Figure 26—Frictional pressure drop – target wellbore

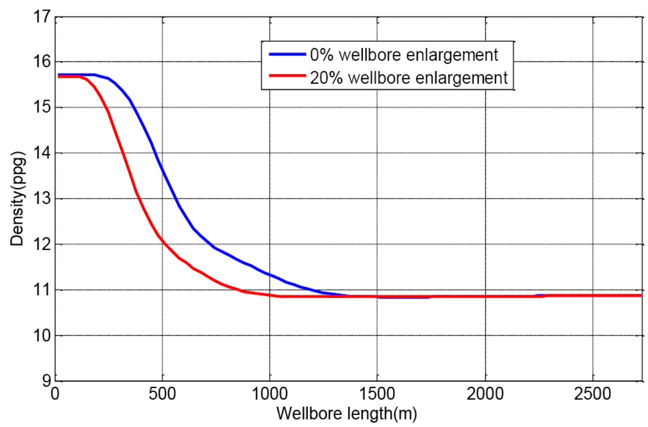

Figure 27—Density profile after cement job done

From Fig. 27, cement bottom is right at the intersection point for both 0% and 20% wellbore volume enlargements. Cement top is 250 m above the intersection point for 0% wellbore enlargement and 150 m above the intersection point for 20% wellbore volume enlargement. Fig. 28 and Fig. 29 show the pressure and temperature at cement top and bottom respectively.

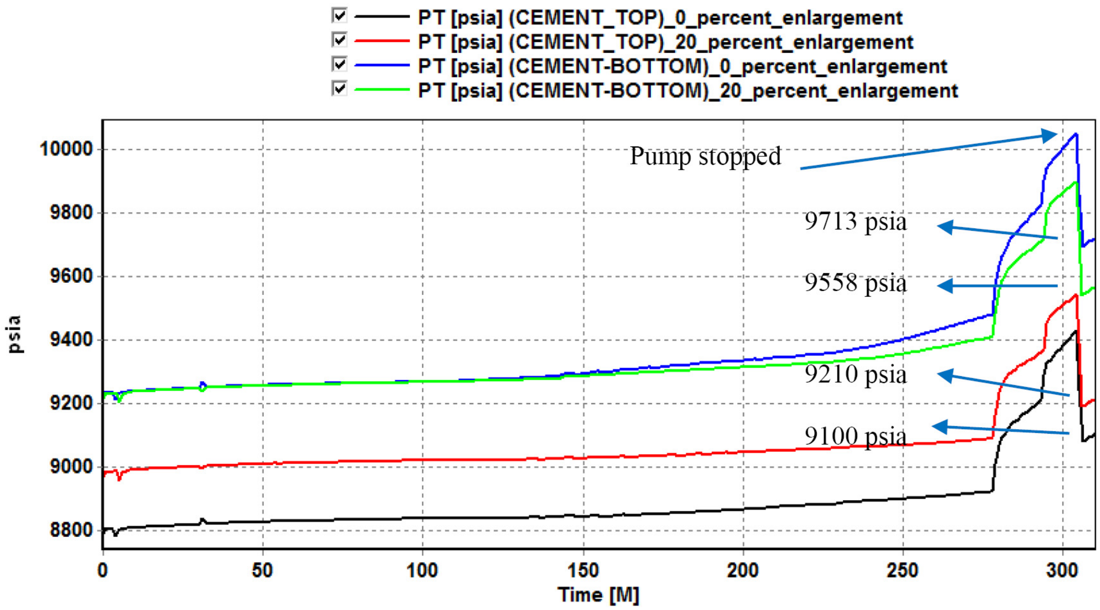

Figure 28—Pressure at cement top and bottom

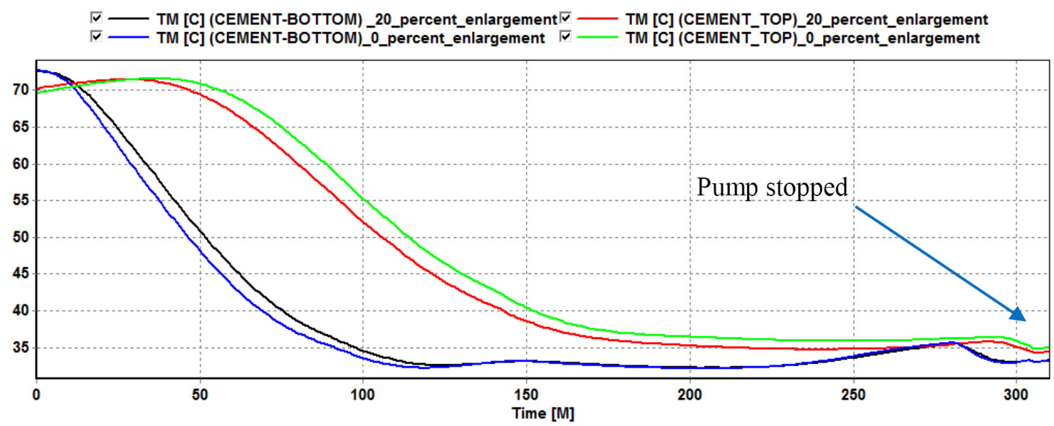

Figure 29—Temperature at cement top and bottom

Reaching turbulence flow is one of the key aspects for achieving a good quality cement job in conventional operations. However, Table 3 shows that the operation is far from turbulence, meaning it is necessary to design special cement slurry or change the operational procedures. Further, it is worth to mention that other aspects are relevant for a successful cement operation, such as the compatibility of the fluids in the system, hierarchy of friction pressure losses, etc.

Table 3—Reynolds Number

	Reynolds Number at 12 bpm			
Open hole Location	**Drilling Fluid**	**Spacer**	**Cement Slurry**	**Velocity at 12 bpm (m/s)**
Relief Well	7250	844	903	0.694
Blowout Well	3870	451	482	0.197

Conclusions

1. As the surface chokes provide back pressure, the injection rates for killing the well in a containment scenario are much smaller than for killing a subsea well, leading to the conclusion that the relief well may be designed considering it. The interception section of the relief well should be designed to have the smallest possible diameter, helping to mitigate free-fall effect and reducing injection and surface production rates.
2. Severe slugging occurs in a significant number of scenarios simulated due to (1) low flow rates of liquid and gas; (2) flow geometry characterized by a horizontal flow line followed by a vertical riser; (3) the flow of gas and liquids with different densities and rheology's.
3. Keeping the same diameters of the flow lines in the containment system and increasing the processing capacity of each vessel, a higher production rate is allowed, possibly reducing the effects of SS. Another benefit is the possibility to reduce the number of legs, reducing the complexity in the coordination of the operations.
4. Besides oil and gas, the surface processing system needs to handle different mixtures of fluids, such as high volumes of drilling fluids with solids and sea water. The possibility of discharging to the environment, after having the fluids flowing through the surface chokes, would add flexibility to the killing operation instead of increasing the processing capacity of the units.
5. The present case of study is a challenging one due to the SS issues. However, it is possible to develop a robust operational procedure to control the blowout well ensuring wellbore integrity during the whole process, despite demanding for: (1) being capable of handling the dynamic behavior of the system based on controlling choke pressures and/or liquid rates at surface; (2) ensuring the integrity of the blowout and the relief well; and (3) avoiding back flow through the relief well.
6. Regarding the cement job for the present case of study, with zero to 20% openhole enlargement, at least, 150 m of good cement can be ensured. However, additional studies are necessary to have final conclusions, above all, if the openhole enlargement is more than 20%.
7. Conventional cement job are evaluated based on the achievement of turbulence while displacing the cement slurry. However, the liquid flow rate constraints imposed by the containment scenario do not favor turbulent flow, leading to the need for designing special cement slurry or changing operational procedures.
8. The execution of a operational procedure to control the well presents some difficulties related to controlling and monitoring, which are: (1) the need to control 3 chokes simultaneously, each one in a different vessel, based on surface pressures and return rates; (2) the need to communicate with the fourth vessel, which is the rig injecting fluids and monitoring pressure at the interception point; (3) a reliable communication system among all operational elements involved is crucial.
9. Understanding the complex transient behavior of the fluids flowing in the system composed of relief well, blowout well, horizontal flexible lines and risers demands extensive computational analysis. The computer simulations are complex, time consuming and request high computer processing capacity. Real time simulation capability is recommended to help to understand unexpected behaviors during the execution of the operation.
10. The development of a robust procedure for controlling an ultra-deep water blowout well under a containment scenario with less than three legs requires additional studies to find ways to effectively mitigate the SS issues.

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Abbreviations

Bbl	Barrel
Bpm	Barrel per minute
Gpm	Gallon per minute
Lbf	Pound force
MD	Measured depth
MMscf	Million standard cubic feet
Ppg	pound per gallon
Scf	Standard cubic feet
SS	Severe Slugging
STB	Standard barrel
TVD	True vertical depth

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