REVIEW OF OPERATIONAL DATA PRECEDING EXPLOSION ON DEEPWATER HORIZON IN MC252

FINAL REPORT
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Executive Summary

The drilling reports and digital data records for the 24 hours preceding the blowout and explosion on the Transocean Deepwater Horizon while it was working on the BP Macondo prospect have been reviewed. The purpose of this review was to identify actions taken in conflict with standard industry practices that contributed to the loss of well control. Two critical operations were identified that were not conducted in accordance with general industry practices and that, in the author's judgment, clearly contributed to the eventual blowout. These were 1) the negative tests of the casing and casing hanger seals and 2) the response to kick indications observed while displacing the riser to seawater.

Purpose

The purpose of this project, per the description of work in order number M10PX00294, is to review the data provided by the Minerals Management Service (MMS, now BOE) "relative to the marine casualty, explosion, fire, pollution, and sinking" of "the Deepwater Horizon, with loss of life, in the Gulf of Mexico" during the 24 hour period preceding the blowout which occurred 20 April, 2010. Specifically the review is "to identify actions that were taken in conflict with generally accepted industry standards or were not taken (not recorded as taken)" or not evidenced in the available data "that would have been called for by generally accepted industry standards." To the extent possible within the time frame of this review, it will include identifying "the specific or likely failures or actions contributing to the loss of well control."

Approach Taken

This review is intended to identify and assess the critical events: actions, inactions, and equipment failures or malfunctions, which contributed, or could have contributed, to loss of the barriers to flow, i.e. to loss of well control. At the time of the blowout, these barriers should have been the primary cement job on the 7"x9-5/8" production casing, the casing itself, the cemented casing shoe, the wellhead packoff at the top of the production casing, and the blowout preventer.

The review will focus on data provided by BP regarding rig activity for 24 hours prior to the explosion on the Deepwater Horizon, which occurred on April 20, 2010 at approximately 10:00 CST. The data that was provided consists primarily of time-based records including a surface drilling data record, a pit volume record, and a cementing unit record and was supplemented with a mud log and a LWD/MWD log. The key information provided to put this data in context were the BP daily drilling reports for the well and the Transocean daily drilling reports from March 18 through April 20. The MMS also provided copies of relevant forms MMS-123, 124, and 133. This information was supplemented as needed by public records. The principal document used was the BP presentation entitled "Washington Briefing – Deepwater Horizon Interim Incident Investigation" dated 24 May 2010 from the House and Energy Commerce subcommittee hearings. Other documents such as the rig specifications from the Transocean website were also used.

The analysis of the data began by correlating the BP daily reports with the BP provided time-based data to determine what the actual quantitative facts are that relate to a specific event or action and whether these facts corroborate the BP daily report. The IADC daily reports were also correlated and reviewed to identify possible omissions or inconsistencies in the BP daily reports and to provide context after the notes on the BP report ended at 6:00 on 20 April. The 24 May BP presentation was used to identify reported actions taken after the last record on the Transocean drilling report at 15:00 on 20 April and is also cited as a reference for data that supplements the recorded data. An edited, supplemented, and annotated file, Macondo BP_Time SDL_4-21-2010-Sorted & Annotated.xls, was created to correlate reported operations with the recorded data and to record the author's comments on the analysis in a correlated manner with the data.

The critical events relating to the eventual loss of well control were then identified, i.e. those events which were potentially involved in the failure of the barriers to flow, to the extent that was possible. The actions taken or not taken which contributed to those events were determined based on generally known and accepted industry practices. MMS regulations, the MMS Forms 123 and 124(APM) for the well, API recommended practices, IADC well control guidelines and training requirements, industry and professional publications, and my own knowledge, experience, and opinions were used to the extent that was practical in this time frame as criteria for defining accepted practices. A list of the specific references cited and an appendix with the Form 124 (APM) are included at the end of the report.

Comparison of BP and IADC Daily Reports and Recorded Data

The BP daily report for the period of interest, 22:00 on 19 April to 21:56 on 20 April 2010, was complete only through 24:00 on 19 April with a supplementary update through 06:00 on 20 April. Although minor differences exist between the BP report and the data, the report is considered valid from a practical perspective. The differences relate primarily to the exact timing of events, to data that was recorded on different sensors and varied in time, and to simple recording (e.g. proofreading) errors. The time differences are expected in a time-based summary of events as tracking the time involved in particular operations to more than about a quarter hour accuracy is impractical in a written summary. There were numerous instances of data occurrences, e.g. changes in recorded pit volumes that were not explained in the report. However, that level of detail is not expected in these reports as it is not generally relevant in a permanent record. There were no errors or omissions in the reports that were deemed significant to the loss of well control.

It is notable that neither the BP daily report nor the Transocean daily report was available for the time periods of the most interest, specifically the negative test and the subsequent displacement of mud from the riser with seawater. This is presumably due to the responsible personnel not yet transferring their personal notes to the reports and is expected given their work schedules.

Review and Discussion of Records

The digital, time-based record of surface drilling data was provided in text and Excel files named Macondo BP_Time SDL_4-21-2010. This was used as the principal factual record of what happened during the time period of interest. It was supplemented with time-based data files of pit volumes and from the cementing unit and images of additional time-based logs of surface drilling data, STL_20100420.pdf, and pit levels, Macondo BP1_Pits_Time_RT.eml. The log of the surface drilling data was especially useful in that it included gas units and also pressure, fluid density, and pump rate from the cementing unit.

The operations conducted during the period of interest were pumping (actually completed before 24 hr period begins) and displacing the cement for the 9.875x7.0" production casing, setting the seal assembly and pressure testing the casing and hanger seal, tripping out with running string, tripping in with work string, preliminary displacing of mud with seawater, negative testing of casing and seals, continued displacing of mud from riser with seawater, and detecting and responding to kick. Each of these operations will be reviewed with emphasis placed on periods contributing to loss of well control. Operations during periods when there was little risk or evidence of actions that would contribute to the loss of casing system integrity or well control were reviewed but are only briefly summarized herein. The subheaders in the following breakdown are a summary statement based on, but not identical to, the description given in the relevant operational time breakdown in the daily reports.

The following begins with BP daily report information for 19 April 2010.

Cementing

20:00 to 22:00 (19 April): Performed cement job

The cement job was the first operation conducted during the 24 hour period of interest. Approximately 62 barrels of 14.3 ppg spacer, 5.4 barrels of 16.74 ppg cement, 48 barrels of 14.5 ppg foamed cement, 7 barrels of 16.74 ppg cement (report is inconsistent and also reports 4 bbl), and 20 barrels of 14.3 ppg spacer were pumped from the cementing unit and displaced with 143 barrels of 14.0 ppg synthetic base mud (SBM). Displacement was made with the rig pumps after 21:42:45. The volumes pumped and the sequence correspond well with the cementing data record. The recorded densities do not match the reported densities. However, the recorded densities correlate with the reported densities, and it is not unusual that the density sensor on a cementing unit is inaccurate. The reported times, volumes, and pressures due to plug displacement also correspond well with the recorded data.

The report states that the rig crew "monitored active pits for gains and losses." Significant gains, roughly equivalent to the volumes of cement and spacer pumped, and losses, which were not explained, are present in the data record. After pumping all of the cement and spacer, there was essentially no net pit gain. An implication is that there were some lost returns during this period, but there was never a total loss of returns. If there were partial losses during this period, there was no likely impact on either well control or the cement job.

22:00 to 00:00: Continued displacing cement with 14.0 ppg mud

This operation to continue displacement with the rig pumps actually began at 21:42:45. The main pit volume increases rapidly during this period. No explanation is given. Then, the main pit volume and main pit gain/loss record ceases to be recorded at 22:54.35. From this time until the end of the data record, main pit volume and gain/loss data is used from the separate pit record data file. Otherwise, there are no significant differences between the daily report and the data record.

Note: The remaining BP daily report information for 20 April is from the "update" section of the 19 April report.

00:00 to 00:30 (20 April): Continued displacing cement, bumped plug, floats held

Displacement of the cement with drilling fluid using the rig pumps continued until the top plug was bumped and the cement was in place.

The reported pressure of 2932 psi to seat and burst the bottom plug is more than that recorded in the data, probably because the data record is an average. The reason for the pressure to be this high is not clear.

The top plug bumped and cement was in place at 00:35, which was reported as 12:35 in the BP daily report. The peak pressure when the plug was bumped was 1189 psi, reported as 740 psi more than the circulating pressure of 449 psi.

The major operational risk to this cement job was probably lost returns during the period of cement placement in the annulus. Both the main pit volume record and the calculated cumulative flow out versus flow in indicate that about 2 to 2.3 barrels of mud was lost during the period that cement was being placed in the casing annulus. This volume is too small to be considered a reliable measurement, but if correct it would only reduce the cement volume in the annulus by about 4 percent. 5 barrels were bled to remove the pressure used to bump the plug, and the floats held the approximately 100 psi differential created by cement and spacer in the annulus.

Significant increases in gas units during this period, to levels exceeding that when drilling non-productive formations, implies that trip gas from previous trip out of the hole had not been circulated out prior to the cement job. However, assessment of pre-job preparations is outside the scope of this review.

Set Seal Assembly and Pressure Test Casing and Hanger Seal

00:30 to 01:00: Released casing running tool and set seal assembly

The running tool was released from the casing and the casing hanger seal assembly was set at 5,059'. The data confirm that the well was static during this period.

01:00 to 02:00: Tested casing hanger seal assembly

The report indicates that upper pipe rams were closed, and the cementing unit used to test the casing hanger seal assembly to 4000 psi for 30 seconds, 10,000 psi for 10 seconds and 6500 psi for 5 minutes. The data record and surface data plot confirm these tests, although the actual pressures were somewhat higher, and the 6500 psi test was held for about 38 minutes, over which time the pressure bled down about 200 psi. This is well within the less than 10% pressure decline in 30 minutes stipulated in Subpart D for an acceptable casing pressure test. The data confirm that the well was static during this period.

02:00 to 02:30: Sheared out of seal assembly

The running tool was sheared out of the seal assembly with 85,000 lb overpull. The main pit volume drops about 35 bbls while circulating to flush the hanger area. There is no explanation, but the BP report indicates the well was being monitored. The gas peaks at 32 units.

02:30 to 03:00: Closed upper pipe rams and tested casing hanger seal assembly

The report indicates that the seal assembly was pressured up to 10,000 psi for 10 seconds, and then pressure was bled to 6500 psi and held for 5 minutes. The data shows that the casing pressure bled from 7201 psi to 7104 psi in 5 minutes, which was appears to be a little faster than during the previous test. No explanation was given for retesting the hanger seals. Possibly this was to confirm that shearing out of the seal assembly did not cause a loss of sealing. The cementing pumps were used to break circulation several times without explanation. The main pits were gaining volume slowly during this period without explanation.

Trip Out with Running String

03:00 to 03:30: Rigged down chiksan lines and laid down cementing kelly

The well was monitored on the trip tank and reported as static. The trip tank volume decreased from 24 bbl to 18 bbl at 03:00 in the recorded data without explanation. This could, but probably does not, imply the well was losing fluid. A gradual increase in pit volume continues, also without explanation.

03:30 to 04:00: Pulled out of hole to 4,770' md

Trip confirmed with data. Monitoring fillup with trip tank is also confirmed, but a thorough check of fillups was not performed for this review. The gradual increase in pit volume continued until all of 40 barrels lost earlier were regained by 04:00. No explanation was provided.

04:00 to 05:00: Circulated 1.5 drillpipe volumes, pumped slug, resumed trip out

The data record shows that circulation began at 400 gpm and 80 barrels were lost from the pit volume over 15 min. It is possible that this loss was due to transferring mud for a slug. Transferred 31.6 bbl to trip tank. Gas exceeded 40 units during this circulation, and there were significant but not large, fluctuations in flow out. Regained all of 110 bbl lost earlier over 30 minutes during this period. Pit volume was stable while pumping, but increased with pumps off without significant measured flow out. No explanation why. Resumed trip out after circulation.

0:500 to 06:00: Pull out of hole with landing string from 4,770' TO 1,000' md

Trip and fillups are confirmed with data.

Note: The BP drilling report ends at this time. The following operational time breakdowns are taken from the Transocean daily drilling report until entries in it end at 15:00. Given that these entries were made prior to the regular time for submitting this report, they might be considered to be preliminary descriptions.

6:00 to 6:30: Continue trip out to 51' md, monitor displacement

Trip and fillups are confirmed with data.

6:30 to 7:00: Lay down running tool, monitor displacement

Removal and fillup confirmed with data.

Although it is obvious that there were significant amounts of gas in the mud circulated from the well during the previous 10 hours, it is likely that this was associated with the previous trip out of the hole. There was no significant evidence of formation flow during this period. No attempt was made to evaluate the fillup record for this trip out because it was made in the riser, fillups were made continuously, and there were almost certainly no swabbing effects. Unless the hole had not been kept full, there were few activities during these operations that should influence the cement job or well control.

Trip In with Work String

This operation was conducted in a different sequence than the sequence in the APM permit. Nevertheless, there was nothing identified about this trip in the well hole or the sequence that conflicts with generally accepted practices or would have contributed to failure of the cement job or loss of well control.

7:00 to 7:30: Cleaned and cleared rig floor, monitored well on trip tank

Data confirms well was static.

7:30 to 8:00: Held pre-job meeting, monitored well on trip tank

Data confirms rig up began and well static.

8:00 to 9:00: Picked up 3.5" and ran to 821', monitored well on trip tank

String depth in data does not agree with report or tally. No reason known. Data confirms displacement being monitored.

9:00 to 9:30: Rigged down 3.5" handling equipment, monitored well on trip tank

Data confirms well is static.

9:30 to 10:30: Ran in from 821' to 4517', monitored displacement on trip tank

Apparently 5.5" and then 6.625" drillpipe was run in based on the BP presentation and cementer's notes provided by MMS. Data confirms running in and displacement being monitored. 20 units of gas measured at the gas detector, apparently from mud being displaced during trip.

10:30 to 12:00: Tested casing and blind shear rams down kill line to 250 psi for 5 min and 2500 psi for 30 minutes

Test confirmed in data. Conducted low pressure test at 221 psi. Bled to 193 psi in 5 minutes. Note: data on plot shows higher pressures, was apparently connected to different sensor. This sensor later proves to read consistently low. Reportedly pumped 6.5 bbl to 2680 psi. Pressure bled to 2520 psi during 30 minute high pressure test, which is within the 10% limit on pressure reduction for a casing test. Bled back 6.5 bbl. Recorded data bled from 2734 to 2677 psi in 30 minutes. This was a combined test of blind shear rams and casing to fulfill the 2500 psi test pressure specified in the APM.

12:00 to 12:30: Held pre-task meeting, monitored well on trip tank

Data implies mud being transferred from trip tank. It is not possible to confirm that the well is static from this data, but there is no indication of flow out at the flow meter.

12:30 to 13:30: Continued running in with 3.5" tubing from 4517' to 8367', monitored displacement on trip tank

This entry is misleading as 6.625" drillpipe was apparently being handled at the surface at this time based on both the BP presentation and on the cementer's notes provided by MMS. The data confirms the trip in and that displacement was being monitored. It also shows that the main mud pit level begins decreasing rapidly at 13:45, apparently due to beginning to offload mud to boats. This would not interfere with monitoring the trip tank.

13:30 to 14:00: Picked up test kelly and rigged up lines, monitored well on trip tank

Data confirms the well was static.

14:00 to 14:30: Halliburton tested lines to 3000 psi, monitored well on trip tank

Trip tank volume increased rapidly about 2 barrels at 14:10. No explanation given.

14:30 to 15:00: Held pre-task meeting on displacing boost, choke, and kill lines, monitored well on trip tank

Data confirms the well was static.

<u>Note:</u> The header descriptions for subsequent actions are based on "data" reported in the BP presentation dated 24 May 2010 for the House Energy and Commerce subcommittee.

Displacement to Seawater in Work String and Boost, Choke, and Kill Lines

15:04 to 15:54: Displaced riser boost line, choke line, and kill line with seawater

This was the first action needed to conduct the negative test on the casing. The pressures required to displace the choke line (1400 psi) and kill line (1440 psi) were expected based on the difference in hydrostatic pressure between 14 ppg mud and 8.5 ppg seawater. The pressure on the kill line subsequently declined to about 1200 psi. The reason for this decline is not certain.

15:56 to 16:28: Pumped 454 bbls LCM spacer

Spacer was pumped into drillstring, presumably to avoid complications resulting from contamination of the synthetic base mud with the seawater during subsequent operations.

16:29 to 16:52: Pumped 352bbls seawater

A volume of seawater was pumped into the drillstring to displace the spacer and drilling mud from the workstring-casing annulus with seawater up to the BOP stack. The reasons for partially displacing the well with seawater at this time, rather than later as indicated in the temporary abandonment plan, are not known but probably include achieving a maximum hydrostatic pressure reduction equivalent to that which would have existed later when spotting the cement plug as a more conclusive test of the casing system.

At the end of this period, there should have 153.29 bbl of seawater in the annulus, with the top at 5117'. The 454 bbl of 16 ppg spacer should have been above that with the top at about 3707'. The expected static standpipe pressure for these conditions was calculated to be 1610 psi. This is much lower than the actual measured pressure of 2339 (SPP2) or 2324 (SPP ave). This implies poor displacement of heavy fluids by seawater in annulus, equivalent to about 1830' of 16 ppg spacer remaining below the BOP. As described in the Analysis section below, this deviation from the apparent plan could have been corrected fairly easily at this time.

Negative Tests on Casing and Hanger Seal

16:53 to 17:05: Shut annular BOP and bled drillpipe pressure to 273 psi

The annular BOP was reported as being closed. Bled drill pipe pressure from 2324 psi to 1427 psi. None of the pits shows a significant gain in the data file. General practice would have been to monitor and record volume bled. Mud may have been bled to and measured at cementing unit. Pressure on kill line began to fall confirming that the valve on kill line at the BOP was opened to balance with drillpipe as reported.

The kill line pressure (recorded as choke pressure) goes to 0 psi with 458 psi on drillpipe (SPP2). This is a strong indication that 16 ppg spacer fluid was not fully displaced from well annulus below the BOP. The BP presentation indicates that a fluid level fall in the riser was noted.

Drillpipe pressure (SPP2) is bled to a minimum of 266 psi. This is almost 200 psi less than pressure to balance the seawater column in kill line. It should give wellhead pressure about 200 to 450 psi less than seafloor pressure, and therefore, a downward differential pressure on the annular preventer of about 2058 psi. Answers to whether the annular BOP is rated to control this downward pressure and what closing pressure on the BOP would be necessary to do so have not been determined in this study.

At this point, it is evident that the apparent intent that the well be filled with seawater from 8367' to the surface (excluding the riser) was not achieved. It is not known why no attempt was made to correct this, possibly because a leak in the annular BOP was suspected at this point. Also, it is very likely that the kill line is no longer full. Depending on the actual average density of the spacer fluids in the well, a fluid level of 450' to 1017' would be expected in the kill line.

17:05 to 17:25: Shut in drillpipe and monitored pressure build up

An increase in drillpipe pressure confirms that the drillpipe was shut in. If this were a successful test, the pressure should not have increased. Also, the maximum drillpipe pressure due to hydrostatics of a full kill line, which was not full, and the remaining 16 ppg spacer in annulus should have been about 714 psi. The actual pressure (SPP2) of 1262 psi at 17:09 is apparently indicates a leak in the annular BOP, the casing, and/or the casing hanger packoff.

The fact that the choke pressure remained less than 0 psi implies that either the kill line valve was closed, the sensors were disconnected or more likely, that the increase in pressure forced the heavy spacer into choke line. For example, if there were a 1200 ft fluid level creating a void that was subsequently filled with 16 ppg spacer, the hydrostatic pressure would have offset the 1000 psi increase in drillpipe pressure. In contrast if the kill line had been full with seawater, the choke pressure should have increased to 1000 psi.

The BP presentation indicates that the riser was being refilled during this time. One potentially confirming indication in the data is that flow out was measured briefly at 17:19. This might mean that the riser had been filled and mud returned to the flowline instead of the trip tank until the fillup pump was turned off. Another is that the trip tank volume varied significantly during the preceding 20 minutes. A total of 67 barrels were measured as having been removed from the trip tank during this period. The trip tank is the most likely source of fluids to fill the riser.

The requirement to fill the riser is a strong indication that the annular BOP was leaking when the pressure was bled down to 266 psi during the preceding period. The fact that the BOP leaked prevents a reliable determination whether the casing or casing hanger was also leaking without accurate measurements of the volume bled to compare to the volume used to fill the riser. The fact that the drillpipe pressure only built back to 1262 psi instead of 2324 psi implies that the BOP was successfully closed at this point. The mechanism or reason for the BOP leak being stopped is unknown. It could be that closing pressure was increased, that another BOP element was closed to achieve the seal, or some other factor. In any event, this first attempt to achieve a casing system test was unsuccessful and inconclusive.

17:27 to 17:52: Bled pressure off drillpipe and closed IBOP

Making a second attempt to achieve a casing system test, having stopped the leak at the BOP, was a logical and practical choice. The attempt was begun by bleeding pressure off of the drillpipe. It is not clear where fluids were bled to. There were small gains on the main pits, the trip tank, and the F/G pit record. Fluids could also have been bled to and measured at the cementing unit (no volume measurements at the cementing unit were provided for this review). The BP presentation shows that witness statements indicated 15 barrels of returns were taken during this bleed. This volume is larger than should have been expected as described in the following analysis section.

The "test" was continued by closing the "IBOP," presumably a drillstring valve in the top drive, which prevented monitoring the drillpipe pressure, and waiting for about 20 minutes. Evidence in the following period indicates that the drillpipe pressure below the IBOP built up during this period confirming the test was not a success. There is no obvious operational intent for this period.

An additional possible concern arising during this period is the 25-35 units of gas recorded over a period of about 35 minutes when there was no circulation. A very slow flow out was recorded with no logical source. Possibilities are a very small leak from the annular BOP or gas in the mud in the riser breaking out of solution, migrating, and causing a slight flow.

17:52 to 18:40: Shut in drillpipe and monitored pressure build up at cementing unit

A third period of bleeding pressure from the drillpipe to the cementing unit and monitoring the pressure build up when shut in at the unit effectively creates a third test attempt. Only pressures were recorded in the data records provided. This sequence began when the pressure monitored at cementing unit increased to 773 psi in about 30 seconds at 17:52. It is likely that this is due to the IBOP being opened to bleed fluid back to cementing unit temporarily imposing pressure on pressure sensor at cementing unit. The drillpipe pressure at cementing unit had bled back to 191 psi by 17:54 and 33 psi by 18:00.

The "interpretation" in the BP presentation includes a conclusion that 3-15 bbls were bled from the kill line to the cementing unit. Because the volumes in the cementing unit measuring tank were not recorded, there is no data evidence for this interpretation. However, a significant volume of flow back was apparently collaborated by the "Cementer witness statement that well continued to flow and spurted." However, there is nothing conclusive in the BP presentation or the reviewed data to confirm this or to indicate whether fluids were bled from the kill line or from the drillpipe workstring.

In any event, the drillpipe pressure at the unit subsequently began building up, presumably because the drillpipe was shut in at the unit. It gradually built up to 1403 psi at 18:36 and stabilized. As in the previous test, the only reason for this pressure to build once bled down is a leak into this supposedly closed system. This and the indications that fluids were bled from the well are evidence of another failed test.

At 18:30, the pressure recorded at SPP1 which had been sensing the kill line pressure also began increasing. It stabilized at about 130 to 140 psi indicating that the kill line was still in communication with the well.

18:40 to 19:55: Monitored drillpipe pressure while opened and monitored kill line

The fourth and final attempt to "test" the casing system was apparently intended to implement the original plan in the APM. The pressure on the kill line (SPP1) was bled down to 102 psi and then a small volume of fluid, about 0.25 bbl, was pumped into the line apparently to be sure that it was full. The peak pressure observed on the kill line while pumping very slowly was 447 psi at 18:42. After pumping stopped, this pressure bled down gradually to about 70 psi over several minutes. This experience confirmed that the kill line was full and was open to the well. The rapid pressure increase also implies that it may have been partially plugged, i.e. pumping this volume into a closed kill line would have increased the pressure to 750 psi versus an expected increase of 86 psi pumping into the full volume of the closed well.

The recorded data for the remainder of this period provides little real evidence of what was happening. The primary parameters in the recorded data were the drillpipe pressure at the cementing unit and the kill line pressure (SPP1). At 19:16, SPP1 decreased from about 70 psi to 38 psi and remained relatively constant for the remainder of this period. The trip tank volume increased 0.2 bbl at this same time, but it is unclear whether this was volume bled and whether it caused the pressure decrease.

The implication from the BP presentation is that the kill line was opened, presumably at 19:16, left open, and monitored as another negative test. If so, the implication that this was intended to be a test on the kill line as described in the APM would be valid.

Presumably, there was no fluid bled from the kill line while it was open, and this was the basis for the decision by rig personnel to continue with the subsequent operation to displace the riser to seawater. A contradictory indication is that the main pit volume increased 22.8 bbl during this period. The accuracy of this measurement is very questionable, and the source of this gain could be almost anything. Nevertheless the trend indicates flow into the pits from somewhere. In addition, the flow out meter indicates total of 3.36 bbl of return flow since 18:33:50. It is almost impossible for this to have been flow from the kill line, and the accuracy for this small volume is questionable. Nevertheless, it could be an indication of a related problem, such as a leaking BOP or gas migrating in the riser.

If in fact there was no flow from the kill line, the fallacy of concluding that this was a successful test is explained and alternatives that would have provided a more reliable test are explained in the following analysis section.

Circulation to Displace Riser to Seawater

19:55 to 21:14: Pumped seawater to displace riser, conducted sheen test on spacer

Circulation to continue displacing mud and spacer from the riser with seawater began at 20:02. The return flow rate was being measured and recorded and the main pit volume was relatively constant providing a good basis for detecting possible kicks. The hydrostatic pressure of the mud and the spacer in the riser is presumably providing more than adequate overbalance to control the well.

The main pit volume begins increasing rapidly at 20:09. No reason is given, but it is probably due to transferring seawater to the main active pits. Flow out (calibrated based on previous measurements) is approximately equal to flow in indicating the well is being successfully controlled.

At 20:20, it is estimated that all of the 16 ppg spacer is above the wellhead, and the pressure at the wellhead should begin decreasing as mud in the riser is displaced with seawater. At 20:23, the displacement rate is increased by starting the riser boost pump. The trip tank volume changes, but no reason is known. The main pit volume has increased to 929 bbl at 20:37, an increase of 500 bbl, which is probably due to transfer in of seawater. The main pit volume stabilizes temporarily.

An apparent loss of mud based on the flow out meter during the period 20:38 to 20:56 is probably the result of flow by-passing the meter. The volume of “loss” at the meter is almost exactly equal to gain in trip tank and main pit volume. Routine well control monitoring is essentially defeated during this period.

The corrected flow out began rapidly exceeding flow in at 20:58. The trip tank volume begins to rapidly decrease simultaneously. This may be because of using the fill up pump to transfer trip tank fluid into the flowline, but the main pit volume is only increasing slightly. The pump rate begins to slow, but return flow remains very high. By 21:05, the main pit volume has increased about 5 bbl at an increasing rate of more than 1 bbl/min, and the calibrated return flow is 11 bbl/min greater than the pump rate. Industry practice would be to treat these as strong kick warning signs.

Circulation was stopped at 21:09 for about 3 minutes, apparently to perform a sheen test on the spacer-seawater mixture being circulated out of the riser. The calibrated flow out during this period begins at 75 gpm or almost 2 bbl/min. Industry practice would be to conclude that this is a positive flow check indicating a kick is in progress, i.e. that formation fluids were flowing into the well, and to shut the well in. This was not done.

The apparent pit gain from 20:58 to 21:13 is 100 barrels. The real gain is uncertain, but would be at least 60 barrels even if 40 barrels of the measured gain was fluid transferred from trip tank. The flow rate from the well increases slightly over the 3 minute period. The drillpipe pressure (SPP2) is increasing with the pumps off, potentially due to 14 ppg mud flowing from the casing or casing annulus into the annulus around the work string and displacing seawater from the top of the riser.

21:14 to 21:31: Resumed pumping with returns overboard, bypassed flow out meter.

Pumping to displace the riser resumed at 21:13 with returns routed overboard despite the indications that the well was taking a kick. With returns going overboard, the main pit level begins decreasing rapidly. Some flow out continued to be indicated until 21:22 although most flow out was apparently by-passing the meter as intended.

The primary pumps on the drillpipe were stopped and restarted at 21:19. The reason is not known. Use of the riser boost pump continued during this period. At 20:27, decreasing drillpipe pressure (SPP2) with constant rate and increasing hook load imply that the downhole pressure is decreasing, possibly due to lower density formation fluids entering the workstring-casing annulus. Conversely, the riser boost line pump pressure (SPP 1) is increasing implying the hydrostatic pressure in riser is increasing, possibly due to 14 ppg mud being displaced into the riser by the formation fluids.

The pump rate begins decreasing at 21:29, and the pumps are stopped by 21:31. No reason is known. A possibility is that the 14 ppg SBM was observed being discharged from the overboard lines.

Detection of and Response to Well Flowing

21:31 to 21:49: Pumps stopped. Well control actions initiated.

At 21:31:40, the drillpipe pressure (SPP2) began increasing, probably because a BOP was closed. The BP information release on 5/12/10 entitled “what we know” indicates that "witness accounts suggest that the annular preventer in the BOP and the diverter were activated." SPP2 reaches maximum of 1781 psi at 21:35:10. This pressure is high enough to warrant shutting in with the variable bore ram (VBR) BOP. No shut in casing pressure is recorded. SPP1 is still decreasing, potentially commensurate with formation fluids displacing and replacing 14 ppg mud, seawater, or maybe more of 16 ppg spacer if still present. A few seconds later, SPP2 begins decreasing rapidly. It is unclear why. A pressure decrease with well shut in is not expected unless something is opened at surface or the BOP began to leak.

At 21:39, SPP2 reaches another maximum of 1368 psi after the preceding decline. The reason for these variations is not known but is likely to be due to opening and closing valves, BOP’s, or chokes. At 21:40:50, the trip tank volume begins increasing. Apparently flow was routed to trip tank intentionally because it starts at 21:40:50 and ends at 21:42:50 after gain of 12 bbl. The source is unknown (e.g. riser, drillpipe or choke line), but this appears to confirm that the well was flowing at a very high rate during this period.

At 21:42:20, SPP2 began increasing. This could be due to flow to the trip tank being shut in. The pumps were started slowly at 21:46. SPP2 begins increasing rapidly at 21:46:55 and the pumps are then stopped. The reason for the rapid increase in pressure is unknown. It could simply be that the well was finally shut in completely. Flow out is also detected. The reason is unknown, e.g. whether flow was routed intentionally to the flow line and meter or a diverter valve is leaking or has failed open. At 21:37:45, the

SPP2 = 2336 psi, and the calibrated recorded flow out was 163 gpm with the pumps off. The maximum calibrated flow out was 828 gpm at 21:48:45. The maximum drillpipe pressure recorded was SPP2 = 5556 psi at 21:49:15, when the data record ends, presumably because of the explosion that occurred at approximately this time.

21:49: Data record ends

The emergency disconnect system (EDS) was reportedly activated at 21:56. Analysis of actions taken after the end of the data record is beyond the scope of this review.

Analysis

Three major failures in the barriers to formation flow are evidenced in the data provided for this review. These failures resulted in the loss of well control and subsequent blowout. The failures are the failure of the primary cement job to isolate productive formations, failure of the casing system to contain annulus pressures, and failure of the well control operations to contain well pressure.

To the extent practical, the actions and events contributing to those failures were identified during the period of interest. The most critical of the actions and events relating to the eventual loss of well control, the evidence defining those events, the relationship to accepted industry practices, and the supporting documentation defining such practices are summarized below. The focus of this review is on comparison of the operations conducted to accepted industry practices and a comprehensive engineering analysis of these failures is not within the scope of the review and is not attempted. The critical actions and events are separated according to the failure which they contributed to.

Failure of Cement Integrity

The main purpose of the primary cement job on production casing is to isolate fluids and pressures in the productive formations from other formations and from the uncemented portions of the well annulus. It is clear that this was not achieved in the Macondo well. The plan, or design, of the cement job has already been critiqued in published hearing statements, and an analysis of the plan is outside the scope of this review. However, placement of the cement and operations during its curing time occurred during the review period.

The major operational risk to the cement job was probably lost returns during the period of cement placement in the annulus. Both the main pit volume record and the calculated cumulative flow out versus flow in indicate that about 2.3 barrels of mud was lost during this period. This volume is too small to be considered a reliable measurement, but if correct it would reduce the cement volume by about 4 percent and the fill height in the annulus by about 49 feet. Differences these small would not be expected to change the results of the cement job.

The primary data collected during cement placement, besides indications of gains or losses, is the pump pressure, especially the "pressure to bump the plug." Ideally, this pressure is measured just before the plug bumps with the pump running at a minimum rate. In this case, the pumps were not slowed down until pump pressure was already increasing, and a traditional measurement of this pressure is not available. Nevertheless, a final circulating pressure of 449 psi at 34 spm was recorded just before the pressure began to increase. Comparing this to the circulating pressure of 342 psi at 34 spm with only mud in the well gives an approximation of 107 psi for the extra hydrostatic pressure in the annulus due to cement and spacer at this time. Although the calculations do not have the degree of accuracy to make good conclusions due to the low density of the foamed cement and the effects of viscosity on circulating pressure, the author calculates that the cement top in the annulus is at roughly 17,270 feet or more than the mandatory 500 feet above the main productive sand (30CFR 250.421(e)) and also slightly more than 500 feet above the higher pressure zone at 17,808 ft.

The only significant complication noted during the cement job was the excessive pressure needed to shear the ball seat from the "DTD," which presumably is a component of the casing running tool. This occurred before the period of review. Given the subsequent indications that the diverter was successfully closed and that plugs bumped essentially as expected (calculations not checked for this review), there do not appear to have been any significant equipment problems during the job.

The lack of symptoms of either severe lost returns (loss in pits and low pressure to bump the plug) or severe channeling (high pressure to bump the plug) indicates that the cement placement was implemented essentially as planned. None of the indications of an inadequate cement job, "lost returns, cement channeling, or failure of equipment," cited in 30CFR Part 250.428 (c) and mandating further cement evaluation were evident.

A subsequent issue is the timing and approach to pressure testing the casing. Pressure testing the casing immediately after bumping the plug is expected to cause the least risk to the sealing integrity of the cement because the cement is still a fluid slurry. Pressure testing the casing after the cement has set establishes the possibility for a microannulus or tensile cracks being created in the solid cement. Nevertheless, testing the casing after cement has set continues to be a generally accepted industry practice. In this case, the casing hanger seals and blind shear rams in the BOP also require a positive test that applies pressure to the casing. So, a pressure test that would affect the cement is necessary following hang off and energizing the seal assembly.

The test of the hanger seals was conducted to high pressures, up to 11,000 psi, but it was completed within about 2 hours after cement placement and probably did not affect cement integrity. The formal test of the casing, and of the blind shear rams, was conducted about 11 hours after the cement was placed, which is during the period when the cement would no longer behave as a fluid. However, it was only conducted to 2500 psi and therefore should have a much lower risk of damaging the cement sheath. This can certainly be considered within general industry practice. Nevertheless, conducting the formal test of the casing and the blind shear rams could have been performed before making the trip out of the hole with the running assembly, which would have further reduced this risk.

No deviations from standard industry practices during this time period were identified that would have contributed to the failure of the cement job.

Failure of Casing System

The main purpose of production casing is to protect the formations and previous casing strings outside the casing from internal pressures resulting from a tubing leak during production (Bourgoyne et al, Applied Drilling Engineering). However in a subsea well during temporary abandonment, the production casing system (including the casing shoe and especially, the casing hanger seals) must contain formation pressures outside the casing when the hydrostatic pressure inside the casing and wellhead is reduced to the hydrostatic provided by seawater. The regulation formalizing this requirement is 30CFR250.442 (e). It states that "before removing the marine riser, you must displace the riser with seawater. You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition."

The production casing system did not fulfill the requirement to maintain a safe and controlled well condition on the Macondo well. Determination of the specific failure: leakage through the shoe track, leakage through the casing itself, or leakage past the casing hanger seals, is beyond the scope of this review. Likewise, determination of the cause of this failure is also beyond the scope of this review. Nevertheless, available insights to these concerns will be provided.

A general industry practice is to maintain at least two barriers to flow during all operations. The mechanisms for providing two barriers to flow during a temporary abandonment are the primary cement job, or remedial cement job if necessary, on the production casing and the casing hanger seals in the wellhead. The approach taken to ensure that these barriers will maintain a safe well condition is two fold. First, the primary cement job is evaluated for adequacy as described in the previous section. This evaluation can include a cement bond log or other techniques, but these were not used in this case. The second, often more conclusive, evaluation that was used is to perform a "negative" or "reverse" test on the casing system prior to displacing the riser with seawater. In fact, the first step in the approved temporary abandonment procedure (MMS-124 [APM] dated 16 April 2010, see Appendix) for the Macondo well was "1. Negative test casing to seawater gradient equivalent for 30 min. with kill line."

The author has planned and conducted negative tests on several liner tops, but a generally accepted industry practice for negative tests was not identified in API or IADC documents or other industry documents available to the author. A simple, logical description was found however, in reference to testing perforations squeezed with cement (E. B. Nelson, Well Cementing). It states that "applying a negative differential pressure … is accomplished by … circulating a light fluid (i.e. through a concentric pipe) … If the sealing achieved … is complete, no inflow should be recorded on a pressure chart." Specifically, there should be no flow of the light fluid returning to the surface through the open pipe, and there should be no pressure buildup recorded when the pipe is closed.

The following summary and analysis of the negative test operations are intended to show how those operations relate to the approved APM, to the loss of well control, and to regular industry practices. Alternatives that would have provided more conclusive tests are also provided.

The riser boost line, choke line, and kill line were displaced with seawater as would be desired to comply with the approved procedure to conduct a negative test on the casing. The pressures required to displace the choke line (1400 psi) and kill line (1440 psi) were as expected. The reason for the subsequent decline in pressure on the kill line to 1200 psi is not known but is not necessarily significant.

A major departure from the approved procedure was pumping 454 barrels of 16.0 ppg LCM spacer to allow the subsequent displacement of the workstring and the workstring-casing annulus in the well with seawater. The purpose of the spacer would be to avoid complications resulting from contamination of the synthetic base mud with the seawater. The reasons for partially displacing the well with seawater are not known but probably include achieving a hydrostatic pressure reduction equivalent to that which would exist prior to spotting the cement plug as a more conclusive test of the casing system. Consequently, this was a desirable adaptation of the planned test. A major disadvantage that was not intended was that a significant amount of dense spacer remained in the workstring-casing annulus and complicated the interpretation of, and increased the severity of, the negative test. This was apparently due to the spacer mixing with the seawater below it in the annulus. A common industry practice to minimize this occurrence is to use an unweighted, viscous spacer to follow a dense fluid that is being displaced up an annulus.

The first attempt was to bleed the drillpipe pressure to 0 psi after having filled it with seawater. This was never achieved, and when shut in, the drillpipe pressure increased to 1262 psi which was apparently due to riser fluids leaking downward past the annular BOP and imposing hydrostatic pressure from above until this pressure was reached. Consequently, this attempt was unsuccessful and was inconclusive relative to casing or hanger seal integrity.

One reason that the test did not proceed as planned was the unplanned presence of dense spacer in the workstring-casing annulus. The data indicates that no action was taken to correct this prior to conducting the test, which could have simplified correct interpretation of test results and would have been an expected response to the complications that were encountered. Specifically, the failure to eliminate this complication was not representative of accepted practice. As noted in the following paragraph, correcting this complication would have been relatively simple.

It should be noted that the spacer could have been displaced, i.e. circulated out, of the well with seawater without significantly compromising its purpose at this time because most of the spacer was already in the riser. The displacement could have been performed while maintaining a constant pressure on the well. One standard industry practice for maintaining pressure constant at the BOP of a well during a pump start up for kick circulation is to monitor the pressure on a static line, usually the kill line used as a "monitor line," to the seafloor. In this case, the choke line was still filled with seawater and could have been used as a monitor line to keep pressure at the seafloor constant while displacing dense fluids out of the kill line with returns through a choke and refilling the well and the kill line with seawater as originally intended. This would have returned the well to the conditions that were originally intended to exist when conducting this test.

Multiple complications occurred as a result of the dense spacer remaining in the well below the BOP. It increased the pressure differential being applied at the casing hanger seals and across the closed BOP during periods when drillpipe pressure was bled down at the surface. As a result during the first attempted test, there were almost certainly several undesirable effects. The fluid level in the kill line almost certainly fell and dense spacer fluids leaked downward past the BOP when the drillpipe pressure was bled off. Consequently, there was then even more dense fluid in the well annulus, and that fluid probably refilled the empty portion of the kill line when the drillstring was closed and the drillpipe pressure built back up. Mixing of these fluids would be a likely reason for the subsequent indications of partial plugging in the kill line. Dense fluid in the kill line would be also be a reason why pressure could be bled off it without causing flow. These complications contributed to apparent confusion about the subsequent tests.

The second attempt involved refilling the riser, apparently taking an unknown action that succeeded in achieving successful (at least reasonably successful, there were possible indications of small amounts of leakage during these tests.) closure of the annulus with the BOP, and then bleeding the pressure off of the drillpipe and measuring the returning volume. The volume expected to be bled back could have been based on volumes used for the earlier casing pressure tests (e.g. 6.5 bbl for a 2680 psi test with SBM in the well) or on a calculated volume change due to fluid compressibility. BP indicates the calculated volume would have been 5 bbl. A simple estimate assuming that the entire system were seawater is 3.7 bbl. Consequently, the reported volume bled back was three to four times the volume that would be expected due to the compressibility of the fluid in the system. This indicates a leak in the casing system. The IBOP on the drillpipe was then closed, and later when it was opened, significant pressure had built up. As noted above, these two symptoms, flow when the test string is open and a pressure build up after it is closed, are exactly what is expected from a failure, i.e. from fluid leaking into the system being tested. It is possible that the volume that was bled back and pressure indicated before the drillpipe was bled again were small enough that this test was also considered inconclusive. In any event, further testing was performed.

The third attempt involved bleeding the pressure off of the drillpipe to the cementing unit. The pressure was successfully bled to zero, but BP acquired records and testimony separate from this data indicate that there was some flow back to the surface during bleeding for this test. More conclusively, a distinct, gradual pressure build up to 1403 psi was recorded when the drillpipe was shut in at the surface. This result would generally be accepted as a conclusive failure of some component in the production casing system, i.e. the casing itself, the cement and valves in the float shoe, or the casing hanger seals. An increase of 1400 psi should not occur in a closed system regardless of there being unbalanced hydrostatics in the system, but rig site personnel apparently decided that an additional test using the kill line, as originally described in the APM was called for.

That fourth and final test attempt involved holding the 1400 psi on the drillpipe with a closed valve at the cementing unit and opening the kill line at the surface to bleed off the 144 psi that had built up on it. The intent was apparently to test the casing and seal against the hydrostatic pressure of a column of seawater in the kill string as called for in the APM. The fallacy in the way this test was conducted is that there was almost certainly a significant height of dense spacer fluid in the kill line by this time.

The following reasoning is provided as an explanation for why dense fluids were present in the kill line. The initial test experienced a pressure at the wellhead, and inside the BOP, between 200 to 450 psi less than seafloor pressure depending on the actual average density of the spacer fluids in the well. A fluid level of 450’ to 1017’ would then have been expected in the kill line. This void in the kill line would have been refilled with dense spacer fluid from the well annulus when the pressure at the wellhead increased as the drillpipe was shut in and drillpipe pressure increased. This effect may have been even more severe in subsequent tests when lower wellhead pressures were experienced due to more of the annulus being filled with spacer that leaked through the BOP during that first test and the drillpipe pressure being bled to 0 psi instead of 266 psi. Also, if the BP interpretation that some fluid volume was bled from the kill line during the third test is correct, the fluid bled would have been seawater and it would have been replaced by additional spacer from inside the well. All of these considerations contribute to the likelihood that there was enough of the 16 ppg spacer (i.e. even though it was mixed with some seawater) to significantly increase the hydrostatic pressure in the kill line relative to being filled with seawater and therefore reduce the negative differential being applied for the test. For example, 1000 feet of 16 ppg spacer in the kill line would have reduced the negative differential applied at the wellhead by 390 psi.

A related, and more complex, possibility is that the leak into the casing system occurred only during periods when the applied negative differential pressure was high, and as already noted the differential at the casing hanger was probably much higher than intended due to the heavy spacer in well annulus. For example, a simplified analysis of differential pressure acting upward on the casing indicates that a reduction in well pressure of 2058 psi, as in the first test, would apply an additional upward force on the hanger of about 570,000 lbs if it acted on the cross sectional area of the casing hanger. The buoyed weight of the casing string in 14 ppg mud is about 510,000 lbs. This potential for a net upward force lifting the casing hanger needs to be evaluated much more carefully to assess the reality, but it creates the potential for the casing hanger seals to be lifted above the sealing area and opening a leak path. This raises the issue of whether the casing hanger lock down sleeve in step 6 of the temporary abandonment procedure should have been run before conducting the negative test. No industry standard approach to this issue was identified in this review, but failure to engage lock down bolts on surface wellheads resulted in the loss of well control.

This last test was apparently considered to be successful, i.e. that there was no leakage of fluid from outside the production casing into the well, when little or no fluid was bled from the kill line over a 30 minute period. However, although the kill line was verified to be full, no attempt was made to ensure that the kill line was actually filled with seawater or that it was not being partially or intermittently plugged. It was almost certainly not filled with seawater at this time. In addition, the differential pressure acting upward on the casing would be greater when the riser and well were fully displaced than when the hydrostatic in the kill line was applied with dense spacer remaining in the well. A realistic conclusion is that this was not an appropriate test, specifically, that it did not apply an adequate (if any) reduction in pressure to achieve a representative negative test.

Reasonable alternative actions could have been taken to achieve a representative test. In addition to the option described earlier which would have achieved the most relevant test, these include: 1) Open valve on choke line and check pressure at top of choke line and then attempt to bleed choke line to zero or 2) Close VBR and line up to pump down kill line with returns up choke line to displace kill line with seawater and then apply 1440 psi kill line and choke line pressure and continue by opening the VBR and bleeding the pressure to retest. Either of these would achieve the level of negative differential contemplated in the kill line test specified in the APM. Option 1) would have required no additional time rig time versus the test that was conducted on the kill line.

In conclusion, both the second and third tests indicated failures, and the third test was readily conclusive. These failures indicated that leaks into the well occurred during both of these tests and that the casing system could not be relied on to contain formation pressures. The critical importance of this test is that it is simultaneously testing both of the barriers to flow, 1) the primary cement job and 2) the casing and hanger seals, that will exist in the annulus of the well once the well is temporarily abandoned. Because these tests were not successful, it was essentially certain that the well would leak creating a well control event during the riser displacement with seawater at which time the only remaining barrier to flow is the BOP.

Failure of Well Control Operations

Temporary abandonment of this well and removal of the rig was necessary while awaiting the equipment and infrastructure required to put the well on production. Removing the rig requires removing the riser which results in the pressure applied to the well at the wellhead being seafloor pressure instead of the hydrostatic pressure of the mud that was inside the riser. The accepted practice is to displace the mud from the riser with seawater before disconnecting the riser and while the BOP is still in place. The basic procedure to do so and to complete the temporary abandonment of the well was documented in the approved temporary abandonment procedure (MMS-124 dated 16 April 2010).

Generally accepted industry practice, which is required by 30 CFR 250250.401 (a) and (c), is that a well be continuously monitored for indications of a kick, and standard well control monitoring and procedures applied “until the well is completed or abandoned.” The two most important monitoring parameters when circulating are the comparison of flow out to flow in and pit gain. Any warning from either of these indicators is a reason to stop circulating and perform a flow check. If the well continues to flow when checked, it is understood that it should be shut in using the BOP. These criteria and procedures are documented in essentially all well control manuals used by industry and are formalized in API RP 59, API Recommended Practice for Well Control Operations and the IADC Deepwater Well Control Guidelines.

A negative pressure test that confirms that a well is secure and will not flow when the mud is replaced with seawater is a logical basis, in practice, for allowing rig operations that may reduce the ability to rapidly detect a kick. These operations might be transferring fluid between active and inactive pits while continuing to circulate or temporarily discharging returns overboard. These might be required on rigs where fluid logistics are limited by pit volumes and plumbing arrangements. However, continued monitoring is both the generally accepted practice and is legally required as explained in the preceding paragraph.

Regular well control monitoring was applied during the initial phase of the displacement. However, from 20:09 to 20:37, the main pit volume increased by 500 barrels, which precluded using pit gain as an effective monitoring criteria. This was probably due to transferring seawater into the main suction pit(s). This loss of monitoring did not directly result in failure to detect a kick, but it most likely created the situation where pit gain was being discounted as a kick monitoring method. It potentially could have been avoided by proper pit management and monitoring.

More importantly, simple monitoring of the data being recorded during the period of 20:38 to 20:56 provides little direct insight into what was happening. The flow out was significantly less than flow in, in a situation where lost returns were unlikely. At the same time, the trip tank volume was increasing rapidly and some increase in the main pits was also recorded, that taken alone could indicate that a kick was in progress. Effective well control monitoring using this data without additional knowledge of rig operations is not possible. This is similar to situations that have contributed to losses of well control in other wells where simultaneous operations on the rig resulted in most rig personnel being unable to analyze the significance of particular data because they don’t know what operations might be occurring that affect that data. This confusion can be minimized by ceasing operations that might induce a problem, such as displacing the riser with seawater, while moving fluids between pits and by not by-passing the flow out meter during such operations.

A large increase in flow out began at 20:58. The accepted action of ceasing circulation to check for flow was not taken. The resulting gain in pit level of about 100 barrels over the next 15 minutes was also ignored. These failures to respond to kick warning signs are in direct violation of standard industry practice and MMS requirements. The confusion described in the preceding paragraph is one probable reason that these warning signs were ignored.

The continued flow from the well while the pumps were turned off at 21:09 is considered, in industry practice and as taught in all well control curriculums, as a conclusive indicator that a kick is in progress, i.e. that formation fluids are flowing into the well. The continued flow of 75 gpm or more during this period is in direct contrast to return flow falling to 11 gpm after 1 minute when pumps were stopped at 16:54. There is no reason or explanation why this should have been ignored. If return flow might have continued because of some operation, such as having the fillup pump turned on, that operation should have been stopped. This failure to identify and shut in the kick in progress while the total gain was less than that which would displace all of the mud from the well annulus is critical in the kick later becoming a blowout.

The subsequent operation to take returns overboard and by-pass the flow meter eliminated all conventional kick detection. Initiating this action without insuring that the well was under control violates all industry practices and regulatory requirements. A logical and simple precaution for conducting this operation when the well is under control (this well obviously was not) would have been to close the BOP and do this final displacement using only the boost line. The logical purpose for closing the BOP during these operations is that the BOP is no longer a useful barrier if it is open and there is no basis for deciding when to close it.

If this approach had been used in this case, it would have shut in the well and stopped the kick. The resulting shut in pressures could have been evaluated and addressed using accepted well control practices for an “off-bottom” kick.

Abnormal well conditions were evidently finally identified about 21:31. BP states that "witness accounts suggest that the annular preventer in the BOP and the diverter were activated." This finally implements the proper reaction that should have been taken in response to flow with the pumps off. It is not known which annular preventer was used, which is relevant because the upper annular had leaked during the negative test. Activating the diverter was appropriate to minimize the risk of hydrocarbon release on the rig floor. A standard step that was not evidenced as being taken was to open the choke line valve and record choke pressure. Knowledge of the choke pressure is generally helpful in diagnosing the severity and the nature of the kick and subsequently for controlling it. It is unknown whether choke pressure was being monitored on the rig floor.

Further evaluation of the actions taken is not definitive because those actions are not known. The large variations in SIDP would not be expected after a successful shut in and may indicate that pressure was being bled intermittently or that the preventers were being opened and closed. The increasing return flow after shut in may have been due to free gas migrating and expanding in the annulus or continuing flow past the BOP or both.

The final drillpipe pressure of 5556 psi at 21:49:15 is approximately the shut in pressure that would be required to stop formation flow if the well was completely full of formation fluid below the BOP and seawater was in the drillpipe. However given that the blowout continued after the explosion that occurred at approximately this time, the well did not remain shut in thereafter even if the BOP was closed and sealing at 21:49.

Conclusions

The following conclusions were based on this review of the accuracy of the BP daily reports and on the analysis comparing the operational actions taken to generally accepted industry practices.

BP Reports

The BP daily report for the period of interest, 22:00 on 19 April to 21:56 on 20 April 2010, was complete only through 24:00 on 19 April with a supplementary update through 06:00 on 20 April. Although minor differences exist between the BP report and the data, the report is considered valid from a practical perspective. The differences relate primarily to the exact timing of events, and this kind of difference is expected is a time-based summary of events as tracking the time involved in particular operations to more than quarter hour accuracy is impractical in a written summary.

Operations

Two critical operations were identified that were not conducted in accordance with general industry practices and that, in the author's judgment, clearly contributed to the loss of well control. These were 1) the negative test of the casing and casing hanger seals and 2) the response to kick indications observed while displacing the riser to seawater. A more detailed explanation of these conclusions follows. There were no indications that the cement job was different than planned. No specific deviations from general industry cementing practices were noted during or following the cement job.

Negative Test on Casing and Hanger Seal

The negative test conducted on the production casing and casing hanger seal assembly was necessary to insure well integrity before the temporary abandonment. The test essentially consisted of four attempts. It is the author's conclusion that all four attempts were unsuccessful and that generally accepted industry practices were not followed in either conducting the tests or in interpreting the results. The failure to achieve a successful, conclusive test indicates that subsequent leakage of formation fluids into the well, i.e. a kick, when replacing riser mud with seawater should have been expected.

The first attempt was to bleed the drillpipe pressure to 0 psi after having filled it with seawater. This was never achieved, and when shut in, the drillpipe pressure increased to 1262 psi which was apparently due to the annular BOP leaking fluid and hydrostatic pressure from above until this pressure was reached. Consequently, this attempt was unsuccessful and was inconclusive relative to casing or hanger seal integrity.

A second test attempt was therefore correctly called for. It involved refilling the riser, successfully achieving shut-in with the BOP, and then bleeding the pressure off of the drillpipe and measuring the returning volume. The reported volume bled back was three to four times the volume that would have been expected due to the compressibility of the fluid in the system. This indicates a leak in the casing system. The IBOP on the drillpipe was then closed, and later when it was opened, significant pressure had built up. This confirms that the test indicates a failure. In contrast, rig site personnel apparently considered it also to be inconclusive.

The third attempt involved bleeding the pressure off of the drillpipe to the cementing unit. The pressure was successfully bled to zero, but built back up gradually to 1403 psi when the drillpipe was shut in at the surface. This result would generally be accepted as a conclusive failure of some component in the production casing system, i.e. the casing itself, the cement and valves in the float shoe, or the casing hanger seals. In contrast, rig site personnel apparently decided that a test using the kill line as originally permitted was required or would be more conclusive.

That fourth and final test attempt involved holding the 1400 psi on the drillpipe with a closed valve at the cementing unit and opening the kill line at the surface to bleed off the 144 psi that had built up on it. The intent was apparently to test the casing and seal against the hydrostatic pressure of a column of seawater in the kill string. This test was apparently considered to be successful, i.e. that there was no leakage of fluid from outside the production casing into the well, when little or no fluid was bled from the kill line over a 30 minute period. However, no attempt was made to ensure that the kill line was actually filled with seawater, and it almost certainly was not at this time. A realistic conclusion is that this was not a test that applied the intended negative pressure differential.

Consequently, the only strongly conclusive test was the third attempt, and it was a failure. The second test had the same, though possibly less conclusive indications of a failure. The critical importance of the negative test is that it was simultaneously testing both of the barriers to flow, 1) the primary cement job and 2) the casing and hanger seals, that would exist in the annulus of the well once the well was temporarily abandoned. If it is not successful, the only remaining barrier to flow while displacing the riser to seawater would be the BOP, and it would need to be applied successfully to control the well.

The failure of rig site personnel to recognize and correct the complications created by the dense spacer remaining in the well during the test, i.e. not conducting the test as designed, is an example of not applying generally accepted practices. The acceptance of results from a single test that was almost certainly invalidated by the presence of the dense spacer in the kill line was obviously a mistake that could have been avoided. Considering the effect of, and then removing, the dense spacer that had entered the kill line during the previous tests would have allowed an effective test to be performed.

Response to Kick Taken while Displacing the Riser to Seawater

Temporary abandonment of a subsea well requires displacing the mud from the riser with seawater before disconnecting the riser and the BOP from the well. Although tests to confirm that the resulting reduction in hydrostatic pressure is safe should already have been performed, the generally accepted industry practice is that the well must continue to be monitored for indications of a kick. The failure to implement this practice to promptly detect the kick and shut in the well almost certainly contributed to the resulting inability to control the kick in this instance.

The two most important kick indicators when circulating are the comparison of flow out to flow in and pit gain. Any warning from either of these indicators is a reason to stop circulating and perform a flow check. If the well continues to flow when checked, it is understood that it should be shut in using the BOP. These basic expectations were not met during the period of 20:58 to 21:30 on 20 April. The size of the resulting kick is unknown, but it was at least 60, and probably 100, barrels by 21:13. That already far exceeds the kick volume that would be expected to be required for detection. The actual kick volume certainly exceeded this and caused significant loss of hydrostatic pressure in the well. Attempting to quantify the actual kick size or its impact on shut in pressures is outside the scope of this review. However, it is certain that the large volume of formation fluids that entered the well contributed to the high pressures encountered and ultimately, to the failure to successfully to shut in the well.

Qualifying Statements

It should be noted that the reviewer had a two week period to consider the events that occurred in this 24 hour period and to consult a variety of published industry references. It is unrealistic to expect rig site personnel to have identified and evaluated all of the complications, alternative explanations, and potential corrective actions addressed in this review. Nevertheless, the fundamental conclusions that 1) the second and third casing system tests demonstrated a system failure that required correction, or at least much more careful testing to contradict the indications of a failure, and 2) the well should have been shut in due to flow at approximately 21:00 on 20 April would be expected to have been reached by rig site personnel following accepted industry practices.

The view, opinions, and/or findings contained in this report are those of the author and should not be construed as an official Government position, policy, or decision, unless so designated by other documentation.

References Cited

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Appendix

MMS-124 [APM] dated 16 April 2010

The approved temporary abandonment procedure per the MMS-124 [APM] dated 16 April 2010 was

1. Negative test casing to seawater gradient equivalent for 30 min. with kill line.
2. TIH with a 3-1/2" stinger to 8367'.
3. Displace to seawater. Monitor well for 30 min.
4. Set a 300' cement plug (125 cu.ft. of Class H cement) from 8367' to 8067'. The requested surface plug depth deviation is for minimizing the chance for damaging the LDS sealing area, for future completion operations. This is a Temporary Abandonment only. The cement plug length has been extended to compensate for added setting depth.
5. POOH.
6. Set 9-7/8" LDS (Lock Down Sleeve)
7. Clean and pull riser.
8. Install TA cap on wellhead and inject wellhead preservation fluid (corrosion inhibitor) below TA cap.