REBUTTAL REPORT

IN RE: OIL SPILL BY THE OIL RIG "DEEPWATER HORIZON" IN THE GULF OF MEXICO, ON APRIL 20, 2010

UNITED STATES DISTRICT COURT

EASTERN DISTRICT OF LOUISIANA

MDL NO. 2179, SECTION J

JUDGE BARBIER; MAGISTRATE SHUSHAN

NOVEMBER 7, 2011

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INTRODUCTION AND STATEMENT OF PURPOSE

Upon the request of counsel representing BP, I have reviewed the expert report of Mr. Donald J. Weintritt and the expert report of Dr. Fredrick "Gene" Beck, both of which were dated October 17, 2011. I am not in agreement with some of the statements and opinions made in these reports that BP was reckless and did not follow standard drilling and completion practices used in the oil and gas industry. The purpose of this report is to point out the most important areas of disagreement and to discuss the reasons why I reached a different opinion.

My opinions expressed in this rebuttal report are in addition to the opinions I expressed in my own expert report, dated October 17, 2010, and I incorporate those conclusions herein as necessary. My qualifications, prior testimony, list of publications and compensation information are provided in that report and I do not repeat them here. While I identify many of my criticisms of Mr. Weintritt and Dr. Beck's opinions, my work is ongoing and I reserve the right to amend or expand these criticisms. Additionally, because I have not highlighted an area of criticism does not mean I agree with other portions of their respective reports.

REPORT OF DONALD J. WEINTRITT, P.E.

Mr. Weintritt concluded that BP departed from normal and accepted practice in industry by using a spacer composition that was inconsistent with standard industry practice. I strongly disagree with this conclusion for the reasons discussed below.

Industry Practice in regard to Displacements and Spacers

BP followed industry practice when they contracted with a service company specializing in providing drilling fluid management and supplies. MI is a world class provider of such services and provided trained and experienced specialists. It is common practice for the well operator to depend on drilling fluid specialists to design, mix and manage fluids and procedures used in a displacement operation.

Industry practice in regard to spacers used in the displacement of a synthetic oil base mud by seawater is that the spacer must:

- be compatible[1] with both the mud and the seawater,
- be of sufficient viscosity and density to efficiently displace the mud out of the well without creating a large volume of contaminated mud,
- have sufficient gel strength and a high enough yield point to suspend the barite and other solids present in the spacer, and
- not be so viscous that it would cause an unacceptable large pressure when pumping at the desired pump rate.

The drilling fluid specialist on the rig checked for fluid compatibility by mixing samples together and noting that there were no adverse reactions. It would have been better if MI had performed a compatibility study in their lab. However, BP also commissioned the "Project Spacer" study after the accident in which a spacer fluid was mixed to be as close a representation as possible of the spacer fluid used on the Macondo well. This later study also did not find any incompatibility problems other than the expected settling of barite and other solids when mixed with an equal volume of seawater or greater.

The density was increased to 16 pounds per gallon to provide for efficient displacement of the 14 pound per gallon mud[2]. The rheology was checked to establish that the gel strength and viscosity was in an acceptable range. A review of the rheology measured later on the Project Spacer fluid confirmed that it would have an appropriate viscosity and would be able to suspend the barite and other solids[3].

Mr. Weintritt speculated in his report that bacterial action would have reduced the concentration of the polymer Duo-vis to such a low value that the gel strength would not have been sufficient to suspend the barite in the spacer when circulation was stopped.

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[1] Compatible means that the spacer mixes with the mud or with seawater without any adverse reactions that would cause the fluid properties to become unacceptable. A mud or spacer that is contaminated by something that is mixed with it will often cause flocculation of the suspended solid particles and the mud or spacer will become too thick.

[2] L. Lindner 9/14/11 Dep. Tr. at 91:14-23 (discussing testing spacer material).

[3] See Project Spacer Report (BP-HZN-BLY00096490-527); MDL Ex. 1 BP's Deepwater Horizon Accident Investigation Report, September 8, 2010 at App. Q.

This reasoning ignores the fact that proprietary components other than Duo-vis were also present in the spacer and that the rheology of the spacer was checked by the mud specialist just prior to its use.

API barite is 4.2 times heavier than water and has a density of about 35 pounds per gallon. Barite is ground fine enough so that almost all of it will pass through a 200 mesh screen. This allows the drilled solids to be removed from the mud without also removing the barite weight material. The largest size barite particle that will pass through a 200 mesh screen will have a diameter of about 0.0035 inches. The theoretical gel strength needed to suspend a barite particle of this diameter in a 16 pound per gallon fluid is only about 1 pound per hundred square feet. In practice, the initial gel is maintained higher than this so that larger sizes of drilled solids can also be suspended. Initial gel strengths greater than 5 pounds per 100 square feet are commonly seen. The initial gel for the 14 pound per gallon synthetic oil base mud used in the Macondo Well was about 14 pounds per hundred square feet. Initial gels for the representative spacer mixed in project spacer were in the range of 25 to 31 pounds per hundred square feet.

Mr. Weintritt assumes in his analysis that the gel strength is so low, that barite not only settles from the bottom of the spacer column where the spacer has become mixed with seawater, but barite would also settle throughout the entire column of spacer and produce alternating slugs of 12-16 pound per gallon mud and 20-24 pound per gallon barite-rich plugs. This is illustrated in Figure 1 of his report. These alternating plugs are shown to have occurred in the riser, the kill line, and the drill-pipe-casing annulus. Mr. Weintritt offers no calculations, experimental studies, or literature references to support this assumption. He cites Stokes Law of settling, but Stokes Law does not predict the described behavior. It is not plausible that the viscosity and gel strength of the spacer would have been so low that settling would have occurred to a significant extent in the parts of the spacer not mixed with seawater. Mr. Weintritt adds flocculation of the barite particles to his theory to make them bigger and heavier, but no flocculation was seen by the mud specialist in the tests that he ran, nor was this reported in Project Spacer. Even if flocculation was occurring, it would not have been limited to just the barite particles, and a flocculated mud generally has much higher gel strength.

Reason for use of Left over LCM pill components in Spacer

Mr. Weintritt indicated that BP and MI chose to combine the left over LCM pills and use them as a spacer between the mud and seawater rather than face the time and expense of hazardous waste disposal.

In my opinion, this is an unfair characterization of the reasons for this decision. In my opinion MI recommended the incorporation of the components of the unused LCM pills into the spacer as a beneficial reuse of this low-toxicity material (which could be released to the ocean) in order to avoid waste, unnecessary expense, and to minimize the volume of toxic waste material that had to be disposed of on land through land farming and other means. When waste with a very low toxicity is combined with toxic waste, the mixture is toxic and the volume of toxic waste that must be processed into the environment on land is increased. MI was under contract to BP to manage the waste material generated in drilling the Macondo well. A fundamental rule of managing toxic drilling fluid waste is not to increase the waste volume by adding low-toxicity materials to the waste stream.[4] From a waste management standpoint, it did not make sense to add already mixed material to the waste stream, and then mix an additional batch of similar material that will then be released to the ocean.

Comparison of Spacer Used to Alternative Fresh Mixed Spacer

It is important to put the amount of LCM particles in the spacer used on the Macondo well in perspective when considering the various expert reports on this topic. I have computed the approximate compositional make-up of the spacer used on the Macondo well using the available records. The pit volume data recorded in the Sperry-Sun real time records is probably the best record of the volumes mixed[5]. These records show that there was about 238 barrels in Pit 5 at about 22:43 hours on April 19, 2010 which has been identified as Form-A-Set in the Lindner deposition and Project Spacer

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[4]Lindner 9/14/11Dep. Tr. at 64-65, "Q. All right. Well -- and -- and I'm not trying to belittle the sentiment at all, but you -- it sounds like your motivation was to improve the environment? MR. TANNER: Objection, form. A. In one way, it was to lessen the waste stream."

[5] See real time pit data available on BP-HZN-BLY00043868, HAL_0243170, BP-HZN-2179MDL00437875.

report[6]. The real time data shows that about 178 barrels was pumped from Pit 3 between 22:43 hrs and 23:00 hrs and this is identified in the Lindner deposition as pumping Form-A-Squeeze material from Pit 3 into Pit 5. The real time data shows the volume of Pit 5 increased by about 155 barrels, which is in approximate agreement considering typical accuracies of pit volume sensors. The MI mixing instructions for April 6, when the pills were prepared is also available[7]. The real time data shows the volume in Pit 5 increased about 40 barrels between 03:12 - 04:30 hours on April 20, 2010. This has been identified in the Lindner deposition as adding barite to increase the density of the spacer from 14 to 16 pounds per gallon. Table 1, which shows a break-down of the final spacer composition, was prepared using this information.

Note in Table 1 that the spacer is primarily fresh water (65.9% by volume) and barite (27.7% by volume). The remaining 5.0% is estimated to be 3.3% LCM fibers and particulates and 1.7% polymer[8]. The polymer provides the needed gel strength and yield point to keep the barite in suspension and makes the spacer sufficiently viscous to control mixing at the leading and trailing edge of the spacer.

The approximately 3.3% of the spacer volume which is fibers or particulates is made of small particles. The Project Spacer report showed that about 60% of the LCM material had a size less than 106 microns (0.00417 inches) and all of it was less than 2 mm (0.078 inches). This material is designed to be able to pass through restrictions in Measurement While Drilling tools and the jets in bits. Bit jet sizes as low as 0.375 inches is common. Mr. Weintritt and I appear to be in agreement that if plugging did occur during the negative test, it was related primarily to the barite in the spacer and the fact that the spacer was not placed and kept above the blowout preventer during the negative test. However, in my opinion, barite settling would occur only in the bottom portion of the

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[6] L. Lindner 9/14/11 Dep. Tr. At 100:16-21, 250:7-11; Project Spacer Report (BP-HZN-2179 MDL 00096490-527)

[7] See MDL Ex. 5144, (April 6 Mixing and Spotting Procedure)

[8] The Material Safety Data Sheet for Form-A-Squeeze Mix lists the compositional ingredients as 7-13% Polysaccharides (polymer), 7-13% mineral, with the remaining content being cellulosic fibers. The Material Safety Data Sheet for Form-A-Set AK Mix lists the composition of ingredients as 15 to 40% Cellulose (fibers) and 0.1to1.0% Silica (crystalline, quartz), with the remaining content being polymer. Assuming 90% of the Form-A-Squeeze Mix and 28% of the Form-A-Set AK Mix and to be LCM fibers and particulates, a volume percent of 3.3% is calculated.

spacer that has mixed with seawater primarily through gravity convection settling during the period that pumping had stopped.

Spacer Component	Specific Gravity	Volume (bbl)	Volume (%)	Weight (lbs)	Weight (%)
Water from Form-A-Squeeze	1	124.6		43,610	
Water from Form-A-Set AK	1	174.9		61,226	
Total Fresh Water in Spacer		299.5	65.9%	104,836	34.3%
Barite from Form-A-Squeeze	4.2	36.7		53,934	
Barite from Form-A-Set AK	4.2	50.2		73,780	
Aditional Barite	4.2	39.0		57,330	
Total Barite in Spacer		125.9	27.7%	185,044	60.6%
Form-A-Squeeze Polymer & Fibrous cellulose Mix	1.73	16.46	3.6%	9,968.0	3.3%
Duovis Polymer	1.1	0.31	0.1%	121.0	0.0%
Form-A-Set AK Polymers & Fibrous cellulose Mix	1.2	10.20	2.2%	4,284.0	1.4%
Form-A-Set AK Retarder	1.1	2.46	0.5%	946.8	0.3%
Total Volume		455	100.0%	305,199	100.0%
Density (pounds per gallon)				16.0	

Table 1 – Macondo Spacer built from LCM pill Components

Spacer Component	Specific Gravity	Volume (bbl)	Volume (%)	Weight (lbs)	Weight (%)
Total Fresh Water in Spacer	1	322.0	70.9%	112,700	36.9%
Total Barite in Spacer	4.2	130.6	28.8%	192,000	62.9%
Duovis Polymer	1.1	1.47	0.3%	567.5	0.2%
Total Volume		454.1	100.0%	305,267.5	100.0%
Density (pounds per gallon)				16.0	

Table 2 – Alternative Spacer if built from unmixed Components

Shown in Table 2 is the approximate composition of an alternative spacer prepared from previously unmixed components instead of building it from components in the previously mixed LCM pills. Note that the main components are similar, with water comprising 70.9% by volume, and barite comprising 28.8% by volume. The spacer used contained about 185,000 pounds (92.5 tons) of barite and the alternative spacer of a similar size would have contained 192,000 pounds (96 tons) of barite.

Size of Spacer

Mr. Weintritt indicated that MI should have used a standard spacer size of 200 bbl. He stated in his report; "Had BP and MI-Swaco used a standard volume of spacer, this event may not have happened." I know of no standard in regard to spacer size. In this case, the column of weighted spacer above the BOP stack gave the option of quickly adding hydrostatic pressure when opening the Blowout Preventer if necessary. The additional spacer height of a bigger spacer was in line with the deeper plug depth that had be planned and approved. Mr. Weintritt also stated in his report that the additional barite in a spacer larger than 200 barrels "may have in some way affected complete closure of the annular preventer on the first attempt." This is not plausible since drilling is sometimes done with mud weights as high as 18 pounds per gallon and barite concentrations approaching 40% and blowout preventers are routinely tested in this environment.

Summary

In summary, Mr. Weintritt's conclusion that BP departed from normal and accepted practice in industry, and that BP used a spacer composition that was inconsistent with standard industry practice appear to be based on statements such as:

- bacteria **may have** compromised these elements while it sat in the mud pits for almost two weeks prior to use.
- the Duo-vis **may not have** been added to the FAS-AK in the first place.
- M-I SWACO's inexperience using LCMs as a spacer **may have** contributed to the mis-formulation described below that led to barite settling from the LCM spacer.
- polymer degradation of the two week old mixture of FAS-AK and Duo-vis **may have** begun as early as 3 to 5 days after it was mixed in Pit 5.
- volume of barite in the stack **may have** in some way affected complete closure of the annular preventer on the first attempt.

- Had BP and M-I SWACO used a standard volume of spacer, this **event may not have** happened.

Finally, Mr. Weintritt did not discuss the fact that the kill line was not plugged when the blowout preventer was retrieved and inspected, which was a flaw in his analysis. I strongly disagree with Mr. Weintritt's conclusions.

REPORT OF DR. FREDERICK "GENE" BECK

Dr. Gene Beck concluded that BP systematically chose to ignore industry standard "Good Drilling Practices," and that BP's decision-making at the rig site on the day of the Macondo well blowout was reckless. Dr. Beck accuses BP of a pattern of conduct whereby BP repeatedly ignored accepted good drilling practices, federal regulations, and its own internal guidelines that required safety to be prioritized ahead of cost and time to production. I strongly disagree with Dr. Beck's conclusions for the reasons discussed below and as set out in my original report. It is my opinion that BP operated within industry standards and consistent with "Good Drilling Practices."

Claim that BP Failed To Follow Its Own Written Practices And Violated Federal Regulations When Operating The Macondo Well.

BP sets very high standards for its operations in its written practices and procedures. On any given decision or action in drilling a well, the written best practices is not always best for the circumstances found on a given well. There must always be provisions for exceptions to the rule. A special circumstance that occurred on the Macondo well was the unexpected encounter of a very sharp and large decrease in formation pore pressure and fracture gradient in the last section of the well. This decrease in pore pressure and fracture pressure was unknown and unknowable until after the section had been drilled and special down-hole tools were used to measure the pore pressure. Because of this special and highly unusual situation, the BP team appropriately made changes in the final well design.

BP has also acknowledged that the drilling team on the rig, which included both BP and Transocean personnel, made a mistake in not correctly interpreting the Negative Pressure Test. However, every member of the team had everything to lose and nothing to gain by making this mistake. This mistake was one of a series of breakdowns in well control that connected together, allowed the blowout to happen. In my opinion, it does not justify a conclusion of willingly and knowingly proceeding with disregard for safety, i.e., being reckless.

Claim that BP Designed A Substandard Well And Prioritized Economics Above Safety

I strongly disagree with this opinion. I saw no evidence to support this opinion in my review of the record and in my review of Dr. Beck's report. As set forth below, many of Dr. Beck's positions are incorrect and none of his arguments persuade me that BP acted outside of industry standard practices.

Figure 1 – Well Plan with Data from APD Approved 3/26/2010

BP did not fail to provide a safe drilling margin. The drilling plan was developed using the best available technology and was a good plan given the available data. Shown in Figure 1 is the drilling plan for the bottom portion of the well as approved on

3/26/2010 at a depth of 15,113 ft[9]. The pore pressure was expected to increase from an equivalent surface mud weight of about 13.1 pounds per gallon to about 14.2 pounds per gallon at the planned total depth of 20,200 feet. The fracture gradient was expected to increase from an equivalent surface mud weight of 14.6 to 15.6 pounds per gallon at the planned total depth. After setting the 11-7/8" casing, the formation integrity test indicated a shoe-strength equivalent to 14.7 pounds per gallon, which was slightly higher than expected. At this point, conditions appeared favorable for finishing the well relatively trouble free.

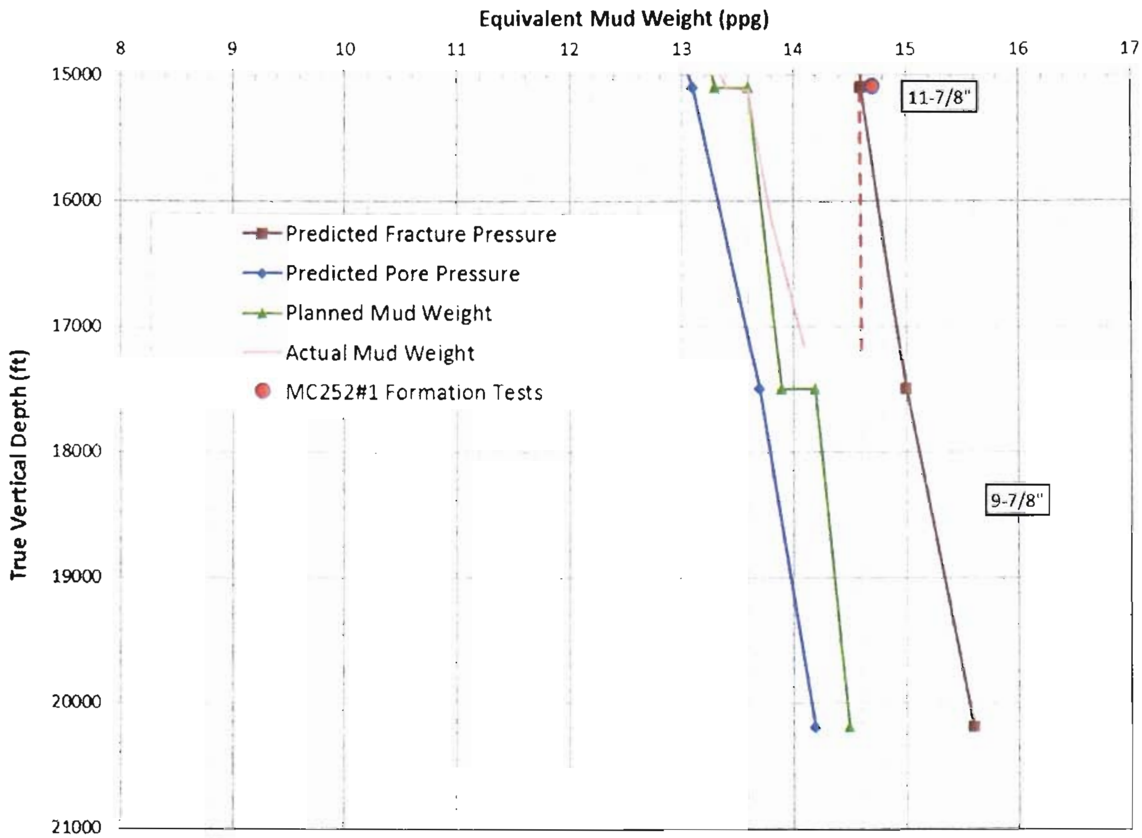

Figure 2 – Well Plan after reaching 17,173 ft

Shown in Figure 2 is the well plan of Figure 1 with updated information obtained after reaching a measured depth of 17,173 feet. The mud weight had been increased to 14.1 pounds per gallon, which was 0.6 pounds per gallon below the shoe strength and

[9] APM approved 3/26/2010, Pore Pressure Gradient, Fracture Pressure Gradient, and Mud Weight Plot BP-HZN-SNR00000973

casing was set before drilling ahead into the target zone to maintain a 0.5 pound per gallon safety margin. After setting a 9-7/8" liner, a shoe-strength of 16.0 pounds per gallon was obtained, which was stronger than the expected fracture gradient[10] of 15.0 pounds per gallon.[11] This test provided confidence that the liner shoe would not break down and that the liner would protect the weaker sediments behind pipe. Conditions continued to look favorable for finishing the well relatively trouble free.

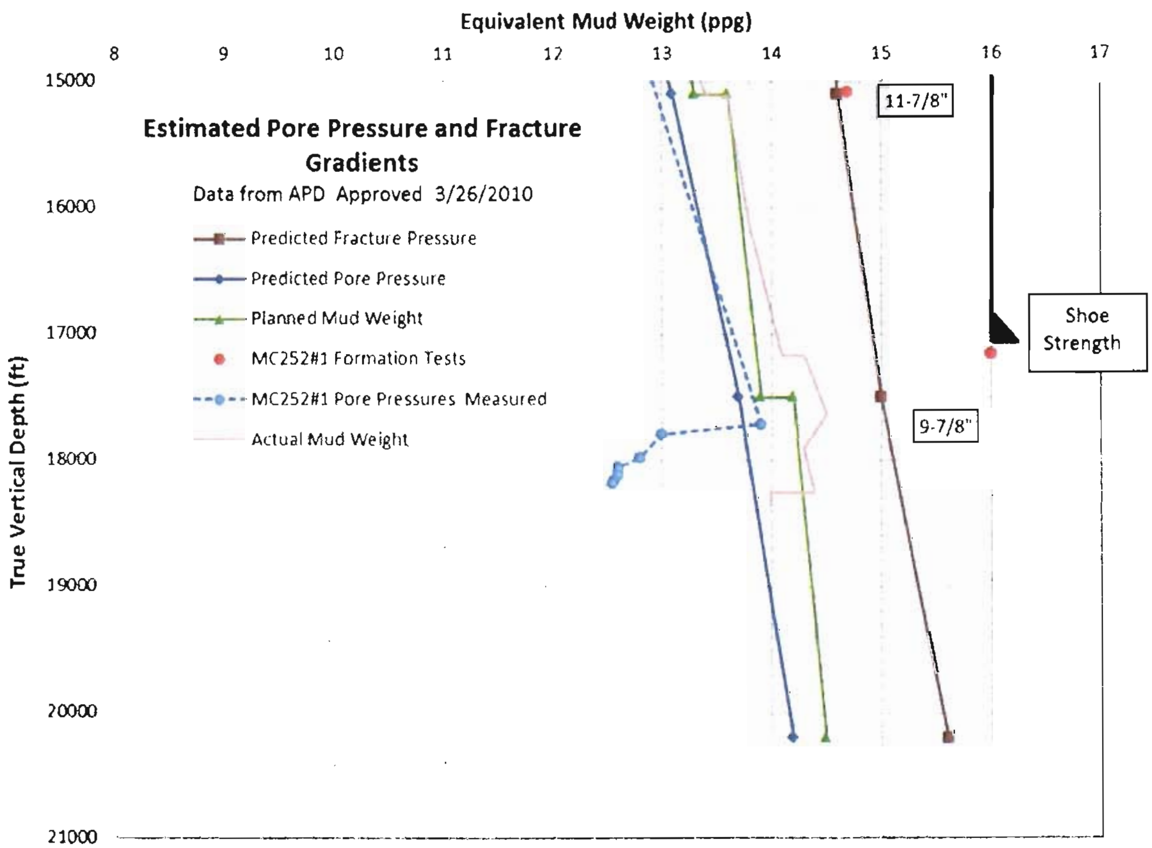

Figure 3 – Well Plan showing Measured Data after reaching 18,360 ft

Shown in Figure 3 is the well plan of Figure 1 with updated information obtained after reaching a measured depth of 18,360 feet. The well was drilled to 17,634 feet and

[10] This Formation Pressure Integrity Test result has been questioned by some because the indicated formation strength or minimum horizontal stress was greater than the overburden stress computed from well logs. I have recently attended a paper (Reference 1 in Appendix B) that shows additional data for Gulf of Mexico deepwater wells in which the minimum stress was greater than the overburden stress.

[11] I discuss this test and why it is valid in my October 17, 2100 expert report at 42-48.

mud weight was increased to 14.5 pounds per gallon. Upon drilling to 17,761 feet, the well began losing mud. The annular preventer was closed and the hole appeared to be ballooning. The zone was treated by spotting Loss Circulation Material at 17,761 feet. The well was drilled to 17,835 feet and the pore pressure was measured with the Geo-Tap tool in the drill string to be equivalent to 14.16 pounds per gallon at 17,807 feet. This is equivalent to a surface mud weight of about 13.9 pounds per gallon. The mud weight was cut to 14.3 pounds per gallon and the well drilled ahead to 17,909 feet. The Equivalent circulating density on bottom while drilling was equivalent to a 14.9 pound per gallon mud and no mud losses were noted at this depth. The well was then drilled to 18,190 feet and the pore pressure at 18,089 feet was measured to be equivalent to a 12.6 pound per gallon mud at 18,089 feet. This showed a steep reversal in the pore pressure versus depth trend that had not been expected and could not have been predicted.[12]

After reaching 18,260 feet, an increase in the mud weight was started to allow the under reamer to be pulled to the surface and changed. Returns were lost while increasing the mud weight to 14.4 pounds per gallon. This indicated that the decrease in pore pressure may have also resulted in a decrease in fracture pressure of the deeper sands being penetrated. At this point the well had penetrated the target sands but it was not clear that the entire sand had been penetrated to the shale below. As mud was lost downhole, the riser was filled with base oil and the well became static with a calculated Equivalent Mud Weight of 13.9 pounds per gallon at the total well depth.[13]

The well was treated with Loss Circulation Material on April 6, and on April 7 the well was static. The drill string was pulled to the surface to chance the worn under-reamer. After returning to 18,227 feet with a new drilling assembly, an ECD of 14.5 pounds per gallon was calculated while circulating. Some mud loss was noted and an LCM pill was circulated into the well. The well was drilled ahead to 18,360 feet to insure

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[12] See Daily Operations Reports for April 2 through April 10, 2010 (BP-HZN-2179MDL00154618-674); IADC Daily Reports for April 2 through April 10, 2010 (BP-HZN-2179MDL00251188-226).

[13] See Daily Operations Reports for April 9 and April 10, 2010 (BP-HZN-2179MDL00154663-674); IADC Daily Reports from April 9 and April 10, 2010 (BP-HZN-2179MDL00251218-226).

the entire sand was penetrated with a 14.0 pound per gallon mud with no losses[14]. The well was circulated clean before pulling out of the hole to log. Logging confirmed the steep decline in pore pressure as shown in Figure 3.[15]

I find the actions summarized above to fall well within normal drilling practice. Dr. Beck indicated that after drilling this well to 18,360 feet and learning of the pore pressure reversal, a prudent course of action would have been to plug the bottom of the well with cement, set a 7-in liner just above the pay zone, and then re-drill the pay zone with a lower mud weight. I have never seen an operator follow such a procedure and there was no need to do so. Cementing open hole is not always leak tight and having two boreholes through the pay zone introduces the risk of cross flow between zones. I saw nothing in the record to suggest that Halliburton recommended such a procedure. Lowering the mud weight and the cement density would not have decreased the potential for the pay zone to flow after cementing. The cement was successfully placed without significant losses during placement. What was needed was a different cement composition that would not have nitrogen gas breakout during the cement displacement.

The use of long string production casing provides a continuous conduit with threaded connections that does not depend on downhole seals where the casing is tied-back. The use of long string production casing is a common option used in the oil and gas industry and clearly falls within normal industry practice. The BP internal investigation cites statistics (Appendix O) that about half (57%) of the production casings used near the Macondo Well in deep water have been long strings.[16] The well did not blowout on the outside of the casing. The evidence clearly shows that the path of the blowout was through the shoe track. A liner and tie-back string design would have the same shoe-track configuration as the long string design.

The use of tapered casing strings has been a common practice for as long as I have been associated with the oil and gas industry. The cementing companies have designed

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[14] See Daily Operations Reports from April 5 through April 10, 2010 (BP-HZN-2179MDL00154639-674); IADC Daily Reports for April 5 through April 10, 2010 (BP-HZN-2179MDL00251201-226).

[15] Wire-line data obtained from BP-HZN-2179MDL00269030.

[16] See MDL Ex. 1, BP's Internal Investigation Report at App. O; MDL Ex. 5347 (MMS email chart of long string casing designs approved in the Gulf of Mexico); D. Trocquet Dep. Tr. at 35-36; 62-64; 198-99.

wiper plugs to accommodate the use of tapered casing strings. The purpose of the shoe joint(s) between the shoe and the float collar is to capture any contaminated cement that builds up in front of the top wiper plug. The use of tapered casing strings clearly falls within normal industry practice.

Dr. Beck did not back up his claim that the use of a long string caused a higher equivalent circulating density than would have been required for a liner with calculations. It has been my experience that the opposite is true. The equivalent circulating density is higher when using a liner because of the high pressure drop through the restriction created by the liner hanger and liner top packer. Further, Dr. Beck's conclusion does not matter because the ECD was properly managed and cement was successfully circulated in place around the long string without any significant loss seen.

The barriers outside of the long string were tested as is normally done for this design. The annular cement and the hydrostatic pressure of the mud above the cement is a barrier that is verified by observing the well does not flow. The seal in the wellhead is a barrier that was also properly tested. The additional testing and seals used with a liner is required because of the potential additional leak point introduced by this design. Flow through a liner top has been a significant cause of blowouts.

Dr. Beck claims that BP used a riskier long string design for financial reasons. I do not agree that the long string design was riskier and economic considerations are a proper part of any engineering design. Both options clearly fell within normal industry practice. The initial cost of the long string is higher than that of a liner. The lifetime cost of a liner and tieback would be higher assuming both options could be installed trouble free without any remedial work required. Mechanical integrity at liner tops and tiebacks are sometimes lost later in the life cycle of a well.

Dr. Beck claims that BP imprudently elected not to use a float shoe in addition to the float collar. The design of the shoe track on the Macondo well clearly fell within normal industry practice. Dr. Beck did not provide any statistics on the use of a float collar and a float shoe on the same shoe track. This practice would make conversion of the float equipment even more difficult when auto-fill equipment is used. The float collar selected had redundant valves built into the float collar.

Claim that BP Failed To Prudently Manage Operations

This accident occurred after the well had been drilled to a total depth of 18,360' and while the Transocean drilling crew was preparing to temporarily abandon the well. I disagree that BP failed to prudently manage operations and dispute many of Dr. Beck's opinions regarding BP's decisions at the Macondo well. Additionally, I note that Dr. Beck downplays the role of the contractors involved in the temporary abandonment operations on the Macondo Well. It is fundamental that the well needs to be continuously monitored at all times, by the Transocean drilling crew and the Sperry-Sun mud loggers. There is always a chance that something bad can happen on the well, and those groups of individuals have the primary responsibility to watch for signs that the well is flowing or losing mud. There was nothing about the operations or the decisions by BP leading up to the blowout that diminished or impaired their ability to monitor the well.

Beyond the fact that the decisions identified by Dr. Beck do not in any way diminish the obligation of the Transocean rig crew and Sperry-Sun mud loggers from monitoring the well, I disagree with many of Dr. Beck's assertions, as discussed in this section.

The drilling plan developed by BP was necessarily designed based on predicted pore pressures and fracture gradients. In my opinion, both the planning and the implementation of the plan clearly fell within normal industry practice. Speculation on how the well would have behaved if different casing points would have been used is easier after the well is drilled and formation pore pressures and fracture gradients are better known. This is especially true when an unexpected and sharp reversal in pore pressure is encountered in the bottom of the well. BP made appropriate adjustments to their well plan as more was learned about the pore pressure and fracture gradient environment. The well was successfully drilled and cement was successfully circulated.

The choice of how many centralizers to use is a subject often debated. Centralizers can help to center the casing, but centralizers can also cause problems when running the casing into the well. The overall risks must be evaluated. Gas flow through cement can occur even when the casing is centered. This phenomenon is affected by cement composition as well as centralization. The number of centralizers used was within normal industry practice.

Gas flow after cementing has been widely studied because of a number of blowouts that have occurred after cementing. When the blowout preventer is at the surface, such as on a platform rig or jack-up, the blowout preventers are sometimes changed from a large size with a lower pressure rating to a small size with a higher pressure rating after cementing intermediate casing. Sometimes gas would begin flowing from the cemented annulus after the large blowout preventer had been removed but before the smaller, high pressure blowout preventers had been installed. This problem was studied at LSU under the sponsorship of MMS (now BOEMRE).

Gas flow after cementing is thought to occur when the cement column gels sufficiently to begin to support a portion of the hydrostatic pressure of the mud above, allowing the pressure in the cement to fall to the pore pressure of a gas-sand. The pressure within the cement column can slowly decrease with time as water filtrate is lost from the cement into permeable formations. Gas flow potential is a parameter used by Halliburton to help identify when conditions warrant the use of special cement formulations, such as nitrified cements, to reduce the risk of gas flow through cement.

Gas Flow Potential at a given gas-sand is the ratio of the maximum theoretical loss in hydrostatic pressure due to cement gelation in the column of cement above that sand to the pressure overbalance present at the sand face at the end of the cement displacement. The computed gas flow potential does not consider all of the important factors, and does not take into account the properties of the cement that combat gas flow through cement. There was no correlation between the computed gas flow potential and the occurrence of gas flow after cementing for the cases studied by LSU[17].

I have reviewed the calculation of the Gas Flow Potential of about 10.2 in the Halliburton Opticem Wellbore Simulator Report dated April 18, 2010 at 11:25 AM[18] and the Draft Halliburton Opticem Wellbore Simulator Report dated May 12, 2010.[19] As explained in Appendix A, a Gas Flow Potential value of 10.2 is ranked as a Flow Condition III, having a severe potential for gas flow after cementing. Halliburton

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[17] See Reference 2 in Appendix B at end of report.

[18] HAL_0117352-HAL_0117384

[19] Post-Incident Opticem Modeling Conducted by CSI Technologies (BP-HZN-2179MDL01160828-918).

recommends their more expensive compressible cements for this condition. I found that the input data for pore pressure to be incorrect in the Halliburton Calculation. The pore pressure entered for the sand at 18,200 feet was 13,200 psi, which was equivalent to a 13.9 pound per gallon gradient. The true pore pressure of the sand at this depth was shown to be about 11,900 psi (equivalent to 12.6 pounds per gallon) from downhole measurements made using both the Modular Formation Dynamics Tester[20] and Geo–Tap[21]. Changing the value of pore pressure from 13,200 psi to 11,900 psi lowers the calculated value of Gas Flow Potential from 10.2 to 1.4, which is a Flow Condition I that is ranked as a minor potential for gas flow after cementing. This Halliburton simulation places the top of cement at 16,121 feet, which is well inside of the 9-7/8" liner.

Dr. Beck calculated a Gas Flow Potential of 54.85 for a zone that he considered to be a two-foot thick gas-reservoir at 17,468 feet. He did not show the details of his calculation, but the high Gas Flow Potential numbers calculated by Dr. Beck appeared to be for upward gas flow through the annulus outside of the casing. This did not happen. The blowout was due to hydrocarbons flowing through the shoe track and up the inside of the casing.

Halliburton's recommendation of more expensive nitrified cement was to mitigate a high Gas Flow Potential. The small nitrogen bubbles make the cement more compressible so that it expands as filtrate is lost to permeable zones and hydrostatic pressure is better maintained until the cement sets.

Dr. Beck claimed that BP should have converted the auto-fill float collar before the casing entered the open borehole. Converting the auto-fill equipment before entering the open hole would have defeated the ability of the auto-fill equipment to meet the required well conditions. The fracture pressure of the low pore pressure zone would likely have been exceeded due to surge pressures associated with lowering the pipe in the well. The well had been circulated clean prior to logging operations. A clean-out assembly was run to bottom after logging and another 1.5 bottoms-up volumes were circulated prior to

[20] Modular Formation Dynamics Tester Complete Report dated May 9, 2010 by Torgerson and Kruzeniski included on BP-HZN-SNR00000007.

[21] GeoTap Pressure Transient Analysis Report dated May 8, 2010 by Kizziar included on BP-HZN-SNR00000003.

running casing.[22] BP's action to not convert the float equipment until the casing was near bottom was consistent with normal industry practice for the well conditions present.

Running a liner instead of a long casing string would not have reduced the surge pressure associated with pipe movement significantly and may have made it worse. The liner hanger and liner top packer create a restriction that significantly increases the surge pressures associated with pipe movement. It has been my experience that sometimes half of the surge pressure occurs due to flow though this restricted area. It would have still been necessary not to convert the float collar until getting the liner near bottom.

Dr. Beck accused BP of being reckless in attempting to convert the float collar. I strongly disagree with this statement. When circulation could not be established, it was apparent that something was plugged. The likely candidates were the reamer shoe, the port in the auto-fill float collar tube, or the landing plate area of the float collar. The first step was to establish the ability to circulate before the well could be circulated at the 5 to 8 barrels per minute needed to convert the float collar. BP made nine attempts to establish the ability to circulate, gradually increasing the pressure until circulation was established by increasing the pump pressure to 3142 psi.[23] Advice was sought from the float collar manufacturer (Weatherford) and from BP engineering.[24] There were no other good options available. Weatherford advised that if the auto-fill tube would not release, the ball would pass through the auto-fill tube without converting at 1300 psi. This feature may have been intended as a safety release to make sure the operator would always be able to circulate cement as intended, even when the auto-fill tube release malfunctioned.

Stress Engineering did an extensive study of a Weatherford float collar of the design used in the Macondo Well.[25] The flow rate surge when the plug came loose was likely high enough to convert the float collar. There were some pressure behavior indications

[22] See Daily Operations Reports for April 16, 2010 (BP-HZN-2179MDL00154290-94); IADC Daily Report for April 16, 2010 (BP-HZN-2179MDL00251247-250)

[23] See Daily Operations Reports for April 19, 2010 (BP-HZN-2179MDL00154306-12); IADC Daily Report from April 19, 2010 (BP-HZN-2179MDL00333592-96).

[24] B. Clawson 6/7/11 Dep. Tr. at 460:15-461:11 (Weatherford witness discussing calls with Brian Morel).

[25] Stress Engineering Services, Inc., Horizon Incident Float Collar Analysis – Report PN 1101198, dated November 22, 2010.

that flow was no longer going through the small port in the tube after circulation was established.

BP did not circulate bottoms up after running the casing to bottom because of a concern that they might begin to lose returns before cementing operations were started. They did circulate the well enough to thoroughly sweep the area of the well that would be cemented. This was reasonable under the circumstances. Losing circulation to a weak zone near bottom was clearly a very undesirable and serious outcome.

The check valves in a float collar or float shoe do not always make a tight seal because of particulates present in the mud. The use of multiple check valves is an attempt at improving the reliability of this device. It is generally not regarded as being reliable enough to consider it to be a barrier.

Dr. Beck concluded that BP unreasonably failed to confirm the function of the check valves in the float collar. From what I was able to determine, a check was made to see if pressures changed at the end of the cement displacement and if the well flowed back when pressures were released at the surface. The conclusion of these checks was that the well did not flow back and that the check valves appeared to be holding[26]. After the fact calculations have shown that there was not enough differential pressure from the annulus to the casing to cause flow after an initial gelation of the mud and cement occurred. In any event, if the system was static, cement gelation could build uninterrupted into set cement.

Dr. Beck indicated that BP should have waited longer before performing the negative test. BP went by cement test data provided by Halliburton in this regard.

Dr. Beck claimed that BP unreasonably canceled the cement bond log previously scheduled with Schlumberger to evaluate the upper annular cement placement. This log would not have been cancelled if circulation had been lost while placing the cement. Since the volume of the annulus had been logged, BP could calculate the minimum

[26] See Daily Operations Reports for April 19, 2010 (BP-HZN-2179MDL00154306-12); IADC Daily Report from April 19, 2010 (BP-HZN-2179MDL00333592-96)

possible cement height. It was reasonable for BP to let the cement completely cure and do cement bond evaluations later during completion operations.

Dr. Beck's claim that BP failed to provide a safe temporary abandonment plan appears to be based on the idea that if it is not done in the manner that he would have done it, then it constitutes reckless behavior. There is a wide variation in industry as to when the lock down sleeve is set, or even if it is set during temporary abandonment. There is also variation in industry practice as to when the cement plug is set. If the plug is set before conducting a negative test, then the primary cement job is not tested. The use muds heavy enough to provide a riser margin before abandonment is not commonly done in deepwater in the Gulf of Mexico because high pore pressure often makes this unpractical. I did not see anything that BP did in the temporary abandonment procedure that fell outside of normal industry practice.

Summary

In summary, Dr. Beck pointed out many things that could have been done differently that in his opinion would have been better. In my opinion, what he does not show is that BP followed procedures or practices that are outside of normal industry practice. On any complex operation, there is always some mistakes made, and in this case BP, Transocean, Halliburton, Sperry-Sun and others made mistakes that were part of a series of breakdowns in well control that allowed the blowout to happen. In my opinion, it does not justify a conclusion of willingly and knowingly proceeding with disregard for safety, i.e., being reckless. Other companies that BP relied on to provide highly specialized services have also made some mistakes that allowed the accident to occur.

APPENDIX A - GAS FLOW POTENTIAL THEORY

When cement slurry is mixed, chemical reactions in the cement cause the consistency and gel strength of the slurry to begin to increase as shown in the idealized schematic of Appendix A - Figure 1. The cement is designed to have a low consistency and gel strength long enough for the cement slurry to be pumped to the desired location. Once in place and pumping is stopped, the gel strength will build as shown in Appendix A - Figure 1. Once the gel strength exceeds a value of 500 pounds per 100 square feet, it has set sufficiently so that gas can no longer deform the cement and establish a gas channel.

As the cement column begins to gel, the gel strength can support a portion of the hydrostatic pressure of the mud above the cement column. The gel is said to restrict the transmission of hydrostatic pressure. The pressure within the unset cement column can decrease if water filtrate is lost from the slurry into permeable zones exposed to the cement. Shown in Appendix A - Figure 2 is a graph of how the pressure opposite the gas sand can decrease with time as the gelled cement column above the gas zone begins restricting the transmission of the hydrostatic pressure of the mud. Note that the greater the initial overbalance of hydrostatic pressure over the pore pressure of the gas sand, the longer it will take for the pressure in the unset cement to fall to the pore pressure of the gas sand. If this time is greater than the time to reach a gel strength value of 500, then gas cannot enter the cement. Note that a cement that builds gel strength rapidly after the cement starts to set (Curve A in Appendix 1-Figure 1) is more desirable because there is less time needed to reach a value of 500.

The pressure restriction per foot of gelled cement is equal to the gel strength in pounds per hundred square feet divided by 300 times the difference between the diameter of the borehole and the diameter of the casing in inches. When the gel strength reaches a value of 500, the Maximum Pressure Restriction in psi is 500/300 or 1.67 times the height of the cement column above the gas zone, divided by the difference between the diameter of the hole and the outer diameter of the casing in inches.

The Gas Flow Potential is defined as the ratio of the Maximum Pressure Restriction divided by the initial Overbalance Pressure. It is an indicator that increases with the height of the cement column above the gas sand, decreases with the diametrical clearance between the borehole and casing wall, and decreases with the initial overbalance pressure. The computed gas flow potential does not consider all of the important factors, and does not take into account the properties of the cement that combat gas flow through cement. Compressible cements that gel quickly once gelation starts are thought to be most effective at combating the potential for gas to flow through cement after it is placed.

Halliburton's Opticem Wellbore Simulator Report of May 12, 2010 calculated the top of cement to be at 16,121 feet when six centralizers were used across the Gas Sand near bottom. This gave a computed height of cement above the gas sand at 18,200 ft of 2079 ft. The apparent average diameter difference computed by Halliburton was 1.685 inches. This gives a Maximum Pressure Restriction of 1.67 x (2079 ft) / 1.685in =2060 psi. The initial hydrostatic pressure at 18,200 ft after cement was placed was about 13,406 psi Halliburton erroneously used a value of 13,204 psi for the pore pressure (equivalent to 13.95 pounds per gallon) to calculate an Overbalance Pressure of 13,406 - 13,204 = 202 psi. This gave a value for Gas Flow Potential of 2060/202 = 10.2. The correct value of pore pressure as measured by both Schlumberger (MDT tester) and Halliburton (GeoTap tester) was about 11,900 psi (equivalent to 12.6 pounds per gallon). This gives a corrected value for the initial Overbalance Pressure to be 13,406-11,900 = 1506 psi and a corrected Gas Flow Potential of 2060/1506 = 1.4. As shown in the scale in Appendix A – Figure 3 below, this is considered to be a minor Gas Flow Potential that does not warrant the recommendation of nitrified compressible cements.

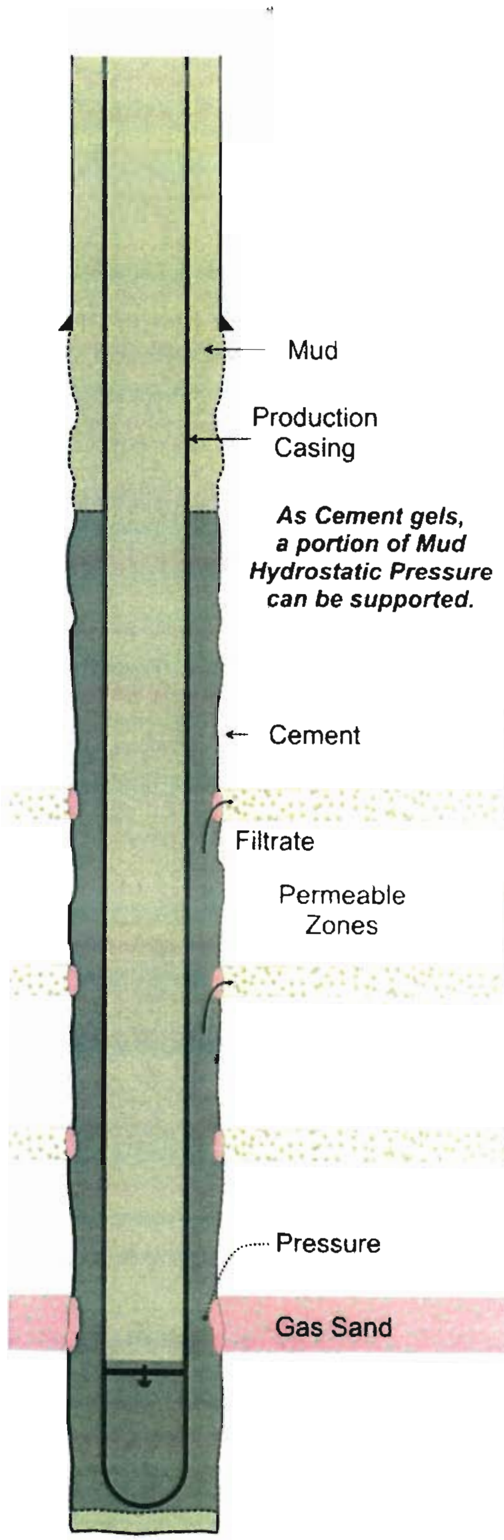

FIGURE 1

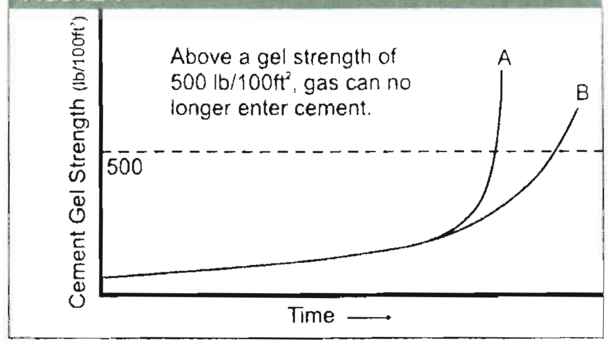

FIGURE 2

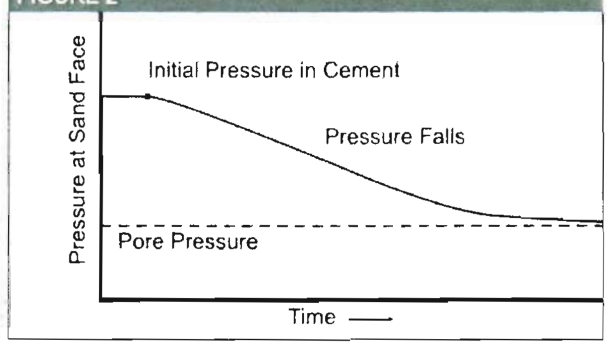

FIGURE 3

$$GFP = \frac{1.67 \times (L/D)}{OBP}$$

L = Height of cement column

D = Average hole diameter - casing OD

OBP = Overbalance pressure
= Formation Pressure - Hydrostatic Pressure

This shows a moderate annular gas flow potential.

Gas Flow Potential Factor

1	2	3	4	5	6	7	8	9	10	∞

Flow Condition I MINOR	Flow Condition II MODERATE	Flow Condition III SEVERE
• Low Fluid Loss • Densified Cements	• Delayed Gel • Thixotropic	• Compressible Cements

Appendix A- Figures 1, 2, and 3

APPENDIX B – MATERIAL REVIEWED

This rebuttal report incorporates the list of materials considered contained in Appendix D of my October 17, 2011 expert report. In addition to the materials identified in Appendix D of my October 17, 2011 expert report and the materials cited in this November 7, 2011 Rebuttal Report, the following materials are added to the list of materials taken under consideration:

1. Li, G., Allison, D. and Bai, M. 2011. Anomalous Pore Pressure and its relation with In-Situ Stress Regime in Deepwater Play, SPE 145686, Annual Technical Conference and Exhibition, Denver, Colorado (October 30-November 2, 2011)
2. Wojtanowicz, A. K., Manowski, Wojtek, and Nishikawa, Somei. 2000. Gas Flow in Wells After Cementing, Technology Assessment & Research Project Final Report by Louisiana State University. TAR-008DL, US DOI, BOEMRE, Washington, D.C., USA (September 5, 2000). http://www.boemre.gov/tarprojects/
3. Crook, Ron, and Heathman, James 1998. Predicting potential gas-flow rates to help determine the best cementing practices, Drilling Contractor (November/Decembe, 1998) pp. 41-43.
4. Harris, K. L., Ravi, K. M., King, D. S., Wilkinson, J. G., and Faul, R. R. 1990. Verification of Slurry Response Number Evaluation Method for Gas Migration Control, SPE 20450, Annual Technical Conference and Exhibition, New Orleans, (September 23-26, 1990).
5. Wang, H., Sweatman, R. E., Engelman, R., Deeg, W. F. J., Whitfill, D. L., Soliman, M. Y., and Towler, B. F. 2008. Best Practice in Understanding and Managing Lost Circulation Challenges. SPE Drilling & Completion (06) DOI: 10.2118/95895-pa.
6. Wang, H., Soliman, M. Y., and Towler, B. F. 2009. Investigation of Factors for Strengthening a Wellbore by Propping Fractures. SPE Drilling & Complet Wang, H., Soliman, M. Y., and Towler, B. F. 2009. Investigation of Factors for Strengthening a Wellbore by Propping Fractures. SPE Drilling & Completion (09) DOI: 10.2118/112629-pa.ion (09) DOI: 10.2118/112629-pa.
7. Fett, J. D., Martin, F., Dardeau, C., Rignol, J., Benaissa, S., Adachi, J., and Pastor, J. A. S. C. 2010. Case History: Successful Wellbore Strengthening Approach in a

Depleted and Highly Unconsolidated Sand in Deepwater Gulf of Mexico. SPE Drilling & Completion (12) DOI

8. SPE Textbook on Well Logging Vol 10