IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF LOUISIANA

IN RE: OIL SPILL by the OIL RIG "DEEPWATER HORIZON" in the GULF OF MEXICO, on APRIL 20, 2010	)	MDL No. 2179
	)	Section: J
Applies to:	)	
ALL CASES and 2:10-cv-02771	)	The Honorable Judge Barbier Mag. Judge Shushan

REBUTTAL EXPERT REPORT OF DR. FREDERICK "GENE" BECK ON WELL DESIGN, CONTROL, DRILLING, AND MONITORING

TABLE OF CONTENTS

LIST OF FIGURES

I. Executive Summary.

My opinions and conclusions in regard to the Macondo well blowout are thoroughly discussed in my October 17, 2011 Opening Report. I have reviewed the expert reports submitted by the other parties involved in this matter and ascertained that the opinions expressed by the other parties' experts most often agree with and support my own opinions, which have not changed. I disagree with certain experts who present opinions that run contrary to my own (a group comprised mostly of experts retained by BP and Weatherford) and find their suggestions unsubstantiated. This rebuttal report addresses the other parties' expert reports and summarizes my key findings.

With the exception of certain experts retained by BP, the experts involved in this matter are in agreement that BP held and exercised ultimate responsibility for the Macondo well. In exercising that responsibility, BP repeatedly prioritized cost and time over safety in disregard of BP's express "safety first" policy, and more consistent with BP's "every dollar counts" mantra. Risk-increasing decisions made by BP to save time and money include, for example, BP's decision to disregard Halliburton's recommendation of placing at least 21 centralizers on the final production casing to avoid the risk of channeling and to use only 6 centralizers instead. In another example, BP decided to disregard Halliburton's recommendation of conducting at least one full bottoms up circulation prior to pumping the cement so that debris and gelling mud would be removed from the well so as to reduce the risk of cement contamination and channeling. And as operations on the well were concluding, BP proceeded with a displacement procedure and simultaneous operations that undermined the rig crew's and mudlogger's ability to accurately monitor the well for signs of a kick.

In prioritizing cost and time ahead of safety, as other experts have recognized, BP violated several MMS regulations. One of the experts retained by BP attempts to paint a different picture by, for example, (1) suggesting that the MMS regulations did not require BP to meet top of cement requirements for the uppermost hydrocarbon zone (the M57B zone) because that zone may not have been "producible" from a royalty standpoint, even though the zone presented a significant safety risk; and (2) suggesting that the MMS regulations did not require BP to conduct a negative pressure test during its temporary abandonment procedure because the regulations do not use the term "negative pressure test"

expressly, even though the regulations clearly require that the well be tested to ensure that it is under control at all times. The same BP expert further suggests that, despite evidence establishing otherwise, BP must have maintained a safe drilling margin simply because the MMS did not issue an INC (incident of non-compliance) to BP during the course of drilling. These suggestions by BP's expert disregard safety concerns.

The other parties' experts appear to uniformly agree with my conclusion that BP and Transocean recklessly explained away the results of the negative pressure test and caused the blowout by significantly underbalancing the well despite the failed negative pressure test. At the time it conducted the negative pressure test, BP was well-aware that it had designed and drilled a high-risk well. Given its multiple risk-increasing decisions in regard to well design and operations, BP should have been on high-alert and exercising extreme caution when conducting the negative pressure test. Instead, BP's conduct was at the other extreme when, in part based upon explanations provided by Transocean, it recklessly explained away indications that the well was leaking. In my opinion, BP's reckless disregard of the test results was motivated by its desire to move forward with its temporary abandonment of the well without incurring additional cost or expending additional time to ensure well integrity and control.

BP's failure to correctly acknowledge the results of the safety critical negative pressure test led to the blowout. Nevertheless, even though BP and its experts acknowledge that BP did in fact misinterpret the results of the negative pressure test, certain experts retained by BP attempt to shift some blame for the blowout to Halliburton's cement work and Sperry's mudlogging operations. I disagree with BP's experts on both fronts.

The experts who attempt to criticize Halliburton's primary cement work offer drastically different opinions, none of which establish that Halliburton likely caused the primary cement job to fail. In my opinion, BP, not Halliburton, caused any problems that existed in regard to the performance of the cement downhole. BP and BP alone decided, for example, to (1) inadequately centralize the well, (2) leave relatively light weight drilling mud in the rathole, (3) adopt a long string production casing, (4) forego a full bottoms up circulation prior to cementing, and (5) not wait at least 24 hours on the cement. Each of these decisions, individually and together, increased the risk that the cement job would fail. BP's failure to convert the float collar without damaging it added to that risk, making it even more likely that there would be problems with the cementing process.

Furthermore, as a number of experts (including one of BP's experts) appear to recognize, the reasonably foreseeable result of a failed primary cement job is a cement repair job—not a blowout. Here, however, to the extent any such cement remediation was needed, BP's disregard of the failed negative pressure test precluded any opportunity for cement repair. BP instead moved forward with its unsafe temporary abandonment procedure whereby it underbalanced the well and opened up the well and riser to dangerous hydrocarbons. BP could have designed a temporary abandonment plan that would have instead left the well in a balanced state at all times so as not to allow in dangerous hydrocarbons—but BP failed to so in its haste to move on to the next well.

The experts who attempt to criticize Sperry's work improperly group the Sperry mudlogger together with the Transocean drilling crew when assigning blame for missing the kick that led to the blowout. Although Sperry and Transocean each played a role in monitoring the well, they were presented with vastly different situations and opportunities for kick detection and response during the final displacement. Whereas the Transocean drilling crew and the BP company man were aware of ongoing drilling operations, the Sperry mudlogger was only aware of the information that BP and Transocean conveyed to him (which was exceedingly limited on the night of the Incident).

During the final displacement, BP and Transocean were complacent and failed to communicate key information to Sperry. BP, Transocean, and M-I SWACO made decisions that blinded Sperry to several primary kick indicators, including pit volume increase, gas concentration, and flow-out data. Additionally, BP and Transocean had constant access to critical flow-out data from a separate Transocean sensor that they did not make available to Sperry. If BP and Transocean had recognized what most assuredly was a substantial increase in flow-out after the sheen test, signaled by an increase in the Transocean flow-out data, the blowout could have been prevented. In contrast, unlike BP and Transocean, Sperry had no clear opportunity to detect the final kick and thus could not have prevented the ensuing disaster.

Several experts also attempt to criticize Sperry for allegedly failing to execute the displacement in a straightforward manner. This criticism is misplaced, as Sperry had no control over how the displacement was conducted. Sperry played no role in drafting, amending, or approving the final displacement procedures, whereas both BP and Transocean were familiar with the displacement plan drafted by M-I SWACO and approved

by BP. BP and Transocean knew the approved displacement procedure would complicate well monitoring by bypassing the Sperry flow-out sensor late in the displacement at a time when the well was likely to be underbalanced. Nevertheless, the Sperry mudlogger accurately monitored the well data available to him, which in real time contained no clear indications of the impending well control situation.

In conclusion, as set forth in my Opening Report and herein, it is my opinion that BP and to a lesser extent Transocean are responsible for the Macondo well blowout and the consequences thereof. Any attempt to shift blame to Halliburton and Sperry is improper and without evidentiary support.

II. Responsibility For The Well: As The Majority Of The Parties' Experts Agree, BP Held And Exercised Ultimate Responsibility For The Macondo Well. Any Contrary Suggestion By BP Is Unsupported By The Evidence.

A. BP held and preserved ultimate responsibility for the design and operation of the Macondo well; BP's ultimate responsibility extended to all operations conducted by Halliburton and Sperry.

Certain experts retained by BP suggest that BP was not ultimately responsible for all well operations. I disagree. As explained in my Opening Report, industry custom dictates that the well operator (here, BP) takes ownership of all procedures, devices, processes, and decisions used in the course of conducting drilling operations.[1] It is the sole responsibility of the well operator to ensure that all operations, procedures, and materials used during the course of drilling a well meet or exceed all applicable regulations and safety standards. The majority of parties involved in this litigation recognize this fact,[2] including BP itself. BP's written practices make it clear

[1] Expert Report of Dr. Frederick "Gene" Beck on Well Design, Control, Drilling, and Monitoring (hereinafter "Beck Report") at 11, 20-22.

[2] *See, e.g.* Rule 26 Report on BP's Macondo Blowout Re: Oil Spill Commencing April 20, 2010 by the Oil Rig Transocean "Deepwater Horizon" in the Gulf of Mexico, Expert Opinion, Basis of Opinion, Analysis and Discussion, prepared by David Pritchard (Plaintiffs), 8/26/2011 (hereinafter "Pritchard Report") at 27; Expert Report Prepared for M-I LLC by George H. Medley, Jr., P.E., 10/25/2011 (hereinafter "Medley Report") at 1-5; Expert Report of Gordon Cain (MOEX), 10/17/2011 at 1, 7-8; Expert Drilling Report of

that BP intends to control all aspects of well design and drilling operations at all times,[3] and BP witnesses have confirmed in their depositions that BP is responsible for directing and conducting all well operations.[4]

BP's ultimate authority is particularly clear in regard to work performed by BP's contractors Halliburton and Sperry (a division of Halliburton). The April 16, 2009 Contract for Gulf of Mexico Strategic Performance Unit Offshore Well Services Between BP Exploration and Production, Inc. and Halliburton Energy Services, Inc. (hereinafter, the "HAL/BP Agreement") provides that Halliburton and Sperry, as "CONTRACTOR[S]," may provide BP with recommendations and opinions related to the work they have been hired to perform. The HAL/BP Agreement clearly states that all recommendations and/or predictions provided by Halliburton and Sperry "shall be received by [BP] as opinions only, and no warranty expressed or implied shall be inferred by [BP] from

---

Roger Vernon (Anadarko), 10/17/2011 at 2; *see also* The Bureau of Ocean Energy Management, Regulation and Enforcement—Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout, 9/14/2011 (hereinafter "JIT Report") at 2; Chief Counsel's Report, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling (2011) (hereinafter "CCR") at 30; Transocean, Macondo Well Incident, Transocean Investigation Report, June 2011 (hereinafter "Transocean Report"), Vol. 1 at 16-17.

[3] Beck Report at 20.

[4] *See, e.g.* M. Sepulvado Depo., 5/11/2011 at 207:13-17 (testimony by BP Senior Wellsite Leader: "[Y]es, BP has the final say."); K. Lacy Depo., 6/2/2011 at 519:7-520:11 (testimony by former BP Vice President of Drilling and Completions, Gulf of Mexico that "[u]ltimately, it is my perspective that the operator has the ultimate responsibility to make the final decision, and it is not uncommon to make a decision counter to an advice or a disagreement on the day."); J. Guide Depo., 5/9/2011 at 157:22-159:16 (testimony by BP Wells Team Leader that BP, as operator, is responsible for the well pursuant to MMS regulations); G. Waltz Depo., 4/22/2011 at 713:2-19 (testimony by BP Drilling Engineer Team Leader that BP was ultimately responsible for well design); G. Walz Depo., 4/22/2011 at 571:18-572:7 (same); P. O'Bryan Depo., 7/15/2011 at 494:9-499:21 and 604:24-605:15 (testimony by BP Vice President of Drilling and Completions regarding BP's various responsibilities for operations on the Macondo well); M. Breazeale Depo., 5/16/2011 at 374:6-9 (testimony by BP Wellsite Leader that the BP well site leader is responsible for "all rig operations insofar as the well is concerned"); K. Corser Depo., 2/10/2011 at 151:20-152:3 (testimony by BP Drilling-Engineering Manager that BP's John Guide was responsible for operations on the rig).

such recommendations…."[5] The contractual provision in question reads as follows:

> **29.3** CONTRACTOR may give COMPANY the benefit of its judgment based on its experience interpreting information and making recommendations, either written or oral, as to DATA or amount of material or type of oilfield service to be provided by CONTRACTOR, or the manner of performance or in prediction of results. Notwithstanding the foregoing, all such recommendations and/or predictions shall be received by COMPANY as opinions only, and no warranty expressed or implied shall be inferred by COMPANY from such recommendations and or in view of the impracticability of obtaining first-hand knowledge of the many variable conditions, the reliance on inferences, measurements and assumptions which are not infallible, and/or the necessity of relying on facts and supporting oilfield services provided by others.

Depo. Ex. 6320 at BP-HZN-MBI-00022200 (HAL/BP Agreement, § 29.3). The express language of the HAL/BP Agreement therefore provides what industry custom already dictates: BP alone is in charge of all drilling operations.

Likewise, the Minerals Management Service (MMS) (now reorganized into two agencies known as the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement) looks to the well operator as the responsible party for the well. The MMS regulations relating to the drilling of wells that were in place on April 20, 2010 are clearly directed at the well operator and it is the well operator who was required to define the well plan and seek permission to drill as specified in that plan.[6]

Despite industry custom, BP's written practices, testimony by BP's witnesses, the HAL/BP Agreement, and MMS regulations establishing that BP was ultimately responsible for all procedures undertaken on the Macondo well, some of BP's experts suggest that Halliburton held and exercised ultimate control over certain well operations. BP's expert Fred Sabins states, for example, that "Halliburton had <u>sole responsibility</u> for the design and testing of the foam cement to ensure a stable foam cement

---

[5] Depo Ex. 6320 at BP-HZN-MBI-000222000 (HAL/BP Agreement, § 29.3) (emphasis added).

[6] *See, e.g.* 30 C.F.R. § 250.105 ("*Operator* means the person the lessee(s) designates as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the MMS-approved designated agent of the lessee(s), or the holder of the operating rights under an MMS-approved operating rights assignment."); 30 C.F.R § 250.400 *et seq.* (setting forth requirements for oil and gas drilling operations in the Outer Continental Shelf).

composition."[7] Mr. Sabins further suggests that Halliburton was solely responsible for execution, monitoring, and reporting on the success or failure of the cement job.[8]

I disagree. Halliburton, as BP's contractor, acted solely at the direction of BP.[9] BP called the shots in regard to all drilling operations, including cementing operations, and was free to disregard any of Halliburton's recommendations (and did in fact do so on more than one occasion).[10] This conclusion is consistent with the conclusion of the United States of America. As explained by the USA's expert Glen Benge, "**[t]he BP wells team was well-versed in cementing. They were the final decision makers and were empowered to accept or reject the advice of both BP's internal cementing expert and Halliburton.** Throughout the drilling of the Macondo well, the BP wells team demonstrated considerable control with respect to cementing design and operations."[11]

Halliburton's lack of ultimate control over any portion of the drilling operations is consistent with industry custom dictating that, as a general rule, contractors are not exposed to reservoir liability. The well operator (here, BP) controls the ownership and development of the well and is in the best position to mitigate or eliminate risks, whereas its contractors are not in a position to be aware of—much less evaluate—those risks. Thus,

---

[7] "Evaluation of the Cementing on the 9 7/8" x 7" Production Casing String on the Macondo Well," Expert Report by Fred Sabins, 10/17/2011 (hereinafter "Sabins Report") at 10 (emphasis added); *see also* Sabins Report at 30, 47.

[8] Sabins Report at 12, 33, 36, 81.

[9] *See, e.g.* R. Sepulvado Depo., 3/10/2011 at 287:5-14 (testimony by BP Well Site Leader: "Q. And to flip it around, you don't proceed to pump cement until you do get the okay from Houston? A. Yes, sir. Q. And I understand that there may be other parties involved but I'm talking about BP well site leader needs approval from its people in Houston, his people in Houston before he can proceed with cement? A. Yes, sir.").

[10] BP did in fact disregard several of Halliburton's recommendations for the Macondo well. BP ignored Halliburton's recommendation that at least 21 centralizers were needed to achieve zonal isolation and avoid channeling, as well as Halliburton's warning, based on its industry-recognized OptiCem™ software, that BP's well design presented a SEVERE gas flow potential. *See* Beck Report at 20-22.

[11] Expert Report of Glen Benge on Behalf of the United States, 8/26/2011 (hereinafter "Benge Report") (emphasis in original).

contractors are not expected to assume operator risk. The well operator stands to make millions (or billions) above and beyond its investment in the well if the drilling operation proves successful. Contractors, in contrast, are compensated pursuant to their written contracts with the well operator, regardless of whether the well proves to be profitable. The risk/reward equation is simple: the well operator holds the right to the potential upside (the biggest reward), making it possible from a financial standpoint for the operator to assume liability for the reservoir (the biggest risk). Because the contractors do not share in the biggest reward, it makes no sense from a financial standpoint for a contractor to share in the biggest risk. As a result, a contractor, such as Halliburton or Sperry, customarily would not agree to perform any work for or on behalf of a well operator such as BP if by making that agreement the contractor was assuming liability for the reservoir. The indemnity clause of the HAL/BP Agreement reflects and is consistent with this industry custom.[12]

In sum, any suggestion that Halliburton ultimately controlled the cement job cannot be reconciled with industry custom, BP's written practices, testimony by BP's witnesses, the HAL/BP Agreement, MMS regulations, or the fact that BP freely ignored Halliburton's advice on more than one occasion. Any suggestion that Sperry held or exercised ultimate control over any aspect of drilling and completion operations would be flawed for the same reasons. BP, as well operator, controlled and directed all operations on the Macondo well.

B. In exercising control over the design and operation of the Macondo well, BP repeatedly prioritized cost and time over safety.

My Opening Report discussed BP's Drilling and Well Operations Practice (DWOP) and associated Engineering Technical Practices (ETPs), which together provide a written framework for designing and conducting drilling operations.[13] BP's DWOP recognizes many of the industry standard "Good Drilling Practices" and dictates that BP wells should be "designed, drilled, and completed to high and consistent standards" and in compliance "with all relevant laws and regulations."[14] As explained by BP's expert

[12] Depo. Ex. 6320 at BP-HZN-MBI-00022184-88 (HAL/BP Agreement, § 19).

[13] Depo. Ex. 6121 at BP-HZN-BLY00034512 (DWOP § 1.2).

[14] Depo. Ex. 6121 at BP-HZN-BLY00034512 (DWOP § 1.2).

Morris Burch, "BP considers the DWOP to be critical to conforming to [BP's safety management system] and achieving BP's goals of no accidents, no harm to people and no damage to the environment."[15]

Significantly, BP states in DWOP § 2.3 that when planning and undertaking drilling and well operations, safety concerns should be prioritized "in order of importance" as Personnel, Environment, The Installation, Reservoir Integrity, and Well Delivery.[16] BP's written practices thus state that safety (personnel, environment) should be prioritized first and time to production (well delivery) should be prioritized last.

BP's written practices, including the "safety first" directive of DWOP § 2.3, are only effective if followed. This was not the case on the Macondo well, where BP repeatedly failed to comply with its own standards and repeatedly prioritized time and money above safety concerns.[17] Take for example BP's decision to cancel the planned cement bond log.[18] Although a cement bond log would have confirmed that the top of cement met planned targets and determined whether channeling or other placement issues produced a result requiring remediation, BP canceled the planned cement bond log prior to temporary abandonment of the well. BP suggests that it was justified in its decision to cancel the planned test because Halliburton did not indicate a need to conduct a cement bond log.[19] I disagree. BP, not Halliburton, was ultimately in control of and responsible for testing the integrity of the cement. BP alone made the risk-increasing decision not to conduct a cement bond log in the interest of saving time and money, and in doing so failed to follow its "safety first" policy.

BP's failure to make safety its first priority in deciding whether to conduct a cement bond log was not an isolated incident. Rather, as discussed at length in my Opening Report, BP engaged in a pattern of conduct on the Macondo well whereby it repeatedly prioritized cost and time ahead of safety concerns. This pattern of conduct was consistent with BP's "every dollar counts" philosophy and rendered the Macondo well a

[15] Report of Morris Burch (BP), 10/17/2011 (hereinafter "Burch Report") at 22.

[16] Depo. Ex. 6121 at BP-HZN-BLY00034516 (DWOP § 2.3).

[17] Beck Report at 23-31.

[18] Beck Report at 87-88.

[19] Sabins Report (BP) at 78-80.

high-risk and dangerous well that was described by BP's own engineers as a "nightmare."[20]

BP's expert Dr. Kathleen Sutcliffe claims that BP did not incentivize cost savings at the expense of safety and that BP "demonstrated the attributes of a strong safety culture."[21] Similarly, BP's expert Mr. Burch opines that BP's risk-management processes and procedures "were appropriately applied during the planning and design of the Macondo well."[22] For the reasons discussed herein and throughout my Opening Report, I disagree. There is no question that BP engaged in a pattern of conduct that increased risk in the interest of saving time and money.

Other parties share my opinion. For example, the Chief Counsel's Report observes that on a drilling rig "time is money" and points to multiple specific decisions by BP "that increased risk at the Macondo well while potentially saving time."[23] Dr. Robert Bea and Dr. William Gale, experts retained by the Plaintiffs, similarly conclude that BP's behavior "resulted in increased risk in proportion to the amount of time and money saved" and cite to exemplary "key Macondo well decisions that increased risk but saved time and money."[24] And David Pritchard, another expert retained by the Plaintiffs, found that "[i]n the final week of the well, BP made ten (10) choices, which were designed to save rig time costing it $1,000,000 a day, and to save money in additional ways. These decisions, taken together, increased the risk of blowout."[25] Thus, I am far from alone in concluding that BP repeatedly increased risk by prioritizing time and money ahead of safety concerns.

---

[20] *See generally* Beck Report at 31-101; Depo. Ex. 126 at CON67.

[21] Expert Report of Kathleen M. Sutcliffe, Ph.D (BP) at 7, 82.

[22] Burch Report (BP) at vi; *see also* Burch Report (BP) at 36-44.

[23] CCR at 245-46 (citing Amendment 41 to Drilling Contract No. 980249; BP-HZN-BLY 125444; BP-HZN-MBI 126763; BP-HZN-MBI 225981; BP-HZN-MBI 269181; HAL_10648; Sims, interview, February 1, 2011; BP-HZN-CEC22433; and Guide Interview, January 19, 2011).

[24] Rule 26 Report on BP's Deepwater Horizon Macondo Blowout, Prepared by Dr. Robert G. Bea and Dr. William E. Gale, Jr., 8/26/2011 (hereinafter "Bea-Gale Report") (BP) at xx-xxi.

[25] Pritchard Report (Plaintiffs) at 17-18.

III. Practice Failures: BP's Expert Is Wrong To Suggest That BP Complied With MMS Regulations. BP Violated Federal Regulations And In Doing So Failed to Follow Its Own Written Practices.

BP's expert Chuck Schoennagel maintains that BP fully complied with the MMS regulatory regime while operating the Macondo well.[26] I disagree. BP's conduct violated at least 30 C.F.R. § 250.421, 30 C.F.R. § 250.427, and 30 C.F.R. § 250.401.

A. BP violated 30 C.F.R. § 250.421 when it disregarded the M57B hydrocarbon bearing zone with respect to top of cement.

Pursuant to the MMS regulation at 30 C.F.R. § 250.421, the well operator is required to set production casing so that the casing is cemented at least 500 feet above the uppermost hydrocarbon-bearing zone. My Opening Report explained that BP misidentified the uppermost hydrocarbon-bearing zone in the Macondo well by claiming the highest hydrocarbon-bearing zone was located at approximately 17,803 feet, even though the uppermost hydrocarbon-bearing zone was actually much higher at 17,467 feet (the M57B sand). Because BP failed to account for the M57B zone, it designed the top of cement to be at only 17,300 feet. BP's well plan consequently was designed to place only 167 feet of cement over the uppermost hydrocarbon-bearing zone in violation of 30 C.F.R. § 250.421.[27]

BP's expert Chuck Schoennagel suggests that BP did not violate this MMS regulation because the M57B zone does not count as a "hydrocarbon-bearing zone" under the MMS regulatory regime.[28] To arrive at this conclusion, Mr. Schoennagel notes that the MMS regulations do not expressly define "hydrocarbon-bearing zone" and reasons that a "hydrocarbon-bearing zone" must be a zone that meets the requirements for "producibility" from a royalty standpoint set forth in 30 C.F.R. §§ 250.115-116. He then concludes that because the M57B zone may not

[26] Expert Report of Chuck Schoennagel L.L.C., MMS Regulatory Regime, 10/17/2011 (hereinafter "Schoennagel Report") (BP) at 19-28.

[27] Beck Report at 47-50.

[28] Schoennagel Report (BP) at 27.

have been "producible" in the royalty context, it must therefore not be a zone that requires cementing in compliance with § 250.421.[29]

BP's expert is wrong. Although the MMS regulations do not expressly define "hydrocarbon-bearing zone," it is uniformly understood in the industry that the gas-bearing zone seen at 17,467 feet in the Macondo well would be capable of delivering a significant volume of hydrocarbons to the wellbore (*i.e.* hydrocarbon-bearing). No definition is needed. In fact, I am not aware of any operator that has or would define "hydrocarbon-bearing zone" to be limited to only those zones that are "producible" from a royalty standpoint. Indeed, BP's regulatory advisor on the Macondo well testified that, if asked by BP's drilling team in regard to a "sand level that's gas bearing and capable of flow and asking you whether they need to cement 500 feet above that," she would have advised them that they had to satisfy the MMS regulation.[30] More important, BP's suggestion that an operator can selectively avoid cementing of a hydrocarbon bearing formation based on its "producibility" under §§ 30 C.F.R. 250.115-116 shows a complete disregard for well safety. The MMS regulation in question, § 250.421, is directed at safety, not royalty considerations. Mr. Schonnagel's contrary suggestion is another reflection of BP's continuing failure to honor its "safety first" policy.

BP was required to set the casing and design the top of cement so that the casing was cemented at least 500 feet above the uppermost hydrocarbon-bearing zone (*i.e.,* the M57B layer) in the Macondo well. BP violated § 250.421 when it failed to do so.

B. BP violated 30 C.F.R. § 250.427 when it failed to maintain a safe drilling margin.

Section 250.427 of the MMS regulations sets forth requirements related to safe drilling margins. Section 250.427(b) requires that "[w]hile drilling, you must maintain the safest drilling margin identified in the approved APD [Application for Permit to Drill]. When you cannot maintain this safe margin, you must suspend drilling operations and remedy the situation." As explained in my Opening Report, BP failed to provide a safe drilling margin in the Macondo well. BP's well design and drilling resulted

[29] Schoennagel Report (BP) at 27.

[30] S. Douglas Depo., 10/11/2011 at 267:2-15.

in little or no drilling margin in the wellbore, and BP did not take available measures to remedy its unsafe drilling margin.[31] As a result, BP violated 30 C.F.R § 250.427(b).[32]

The United States Department of Justice agrees with me on this issue. Its expert Dr. Alan R. Huffman opines that "[o]n multiple occasions, BP failed to maintain a 'safe drilling margin' while drilling the Macondo well."[33] Dr. Huffman concludes that, under his interpretation of the MMS regulations, BP's failure to maintain a safe drilling margin violated not only § 250.427(b), but also §§ 250.401, 250.427(a), and 250.428(a).[34] I have reviewed Dr. Huffman's opinions on the drilling margin and agree with him. His conclusions are consistent with and support my conclusions that BP had little or no remaining drilling margin and that the Macondo well, as drilled by BP, was dangerously unstable.

BP suggests that it complied with the MMS regulations relating to safe drilling margins because "no INCs [incidents of non-compliance] were issued to BP relating to safe drilling margins during the course of drilling the well."[35] I disagree. BP failed to maintain a safe drilling margin for the reasons discussed above and in my Opening Report, as well as the reasons set forth in Dr. Huffman's expert report, and the non-issuance of an INC during the course of drilling the well is not proof to the contrary. BP was required to maintain the safest drilling margin identified in its Application for Permit to Drill (*i.e.,* 0.5 ppg, absent a waiver)[36] during the course of drilling and, if it could not maintain that safe margin, suspend operations and remedy the situation. BP repeatedly violated § 250.427(b)

---

[31] Beck Report at 31-36.

[32] Beck Report at 31-36.

[33] Expert Report of Dr. Alan Huffman Submitted on Behalf of the United States Department of Justice, 8/26/2011 (hereinafter "Huffman Report") at 5.

[34] Huffman Report (USA) at 5.

[35] Schoennagel Report (BP) at 23-24.

[36] BP's APD was filed on May 13, 2009. Depo. Ex. 4021. BP represented to the MMS that, absent a waiver, it would maintain a 0.5 ppg margin between its mud weight and fracture gradient while drilling the Macondo well. BP sought and received three waivers from the MMS to drill with less than a 0.5 ppg margin, but in no case did BP request a waiver to less than 0.3 ppg. *See* Huffman Report (USA) at 16-21.

when it failed to do so.

C. MMS regulations, specifically § 250.401, required BP to conduct a negative pressure test as it prepared to temporarily abandon the Macondo well.

BP's expert Mr. Schoennagel suggests that because "the regulations at 30 C.F.R. § 1721 through 30 C.F.R. § 1723, covering Temporarily Abandoned Wells, do not require that a negative pressure test be conducted when temporarily abandoning a well," it was not required to conduct a negative pressure test as part of its temporary abandonment procedure on April 20, 2010.[37] I disagree. Although §§ 1721-23 do not expressly require a negative pressure test, the MMS regulatory regime does contain such a requirement in § 250.401. That section requires a well operator to "take necessary precautions to keep wells under control at all times" and, as discussed below, in the case of the Macondo well such "necessary precautions" included a negative pressure test.

As discussed in my Opening Report, because a successful negative pressure test establishes the ability of the well to withstand conditions that would normally induce flow, it is the most critical test that is run by the well operator prior to removal of the blowout preventer.[38] Thus, in my opinion, a negative pressure test was a "necessary precaution[] for keeping [the Macondo well] under control." BP itself recognizes this in its own written standards, which demand that two independently pressure tested barriers be in place along any potential flow path to the seafloor.[39] In fact, had BP properly interpreted the results of its negative pressure test during temporary abandonment of the Macondo well, it would have known that all of its expected barriers for one of the potential flow paths had failed.[40] On the other hand, if BP had not conducted the negative pressure test during its temporary abandonment procedure (as it claims it was not required to do), it would have had no chance of discovering that failure. Accordingly, I believe that any suggestion by BP's expert that a negative pressure test

[37] Schoennagel Report (BP) at 25.

[38] Beck Report at 92.

[39] Beck Report at 91-92 (citing Depo. Ex. 6121 at BP-HZN-BLY00034588; Depo. Ex. 184 at 2-3).

[40] Beck Report at 93.

during temporary abandonment was not a "necessary precaution" for well control is disingenuous.

In sum, in my opinion, BP did not comply with the MMS regulatory regime while operating the Macondo well. For the reasons discussed above and in my Opening Report, BP's conduct violated at least 30 C.F.R. § 250.421, 30 C.F.R. § 250.427, and 30 C.F.R. § 250.401. Additionally, in violating the foregoing federal regulations, BP also failed to follow § 2.2 of its DWOP, which provides that "[a]ll drilling and well operations shall be planned and performed in compliance with all applicable legislation and regulations."[41]

IV. The Negative Pressure Test: As Other Parties' Experts Agree, BP And Transocean Caused The Blowout By Disregarding The Results Of The Negative Pressure Test And Proceeding To Significantly Underbalance The Well Without First Ensuring Well Integrity.

All experts addressing the results of the negative pressure test appear to agree that BP and Transocean were wrong to deem the negative pressure test a success,[42] and BP and Transocean previously acknowledged this in their public reports.[43] No expert suggests that BP

[41] Depo. Ex. 6121 at BP-HZN-BLY00034516 (DWOP § 2.2).

[42] Expert Report on Behalf of BP, Robert D. Grace, P.E., 10/17/2011 (hereinafter "Grace Report") at 17 ("I believe the Negative Test should not have been declared a success"); Expert Report of Calvin Barnhill, Macondo Engineering, Operations and Well Control Response, 9/23/2011 (Transocean) (hereinafter "Barnhill Report") at 32 ("The negative testing revealed that the Macondo Well lacked integrity and was not secure"); Expert Report of David G. Calvert, 10/14/2011 (Weatherford) (hereinafter "Calvert Report") at 12 ("[T]he negative pressure test should have been considered a failure"); Expert Report of J.J. Azar, Ph.D. (BP) (hereinafter "Azar Report") at 46 (the negative pressure test was "misinterpreted by everyone"); Expert Report of Adam T. Bourgoyne, 10/17/2011 (BP) (hereinafter "Bourgoyne Report") at 62 (the misinterpretation of the negative pressure test is "extremely hard to understand"); Expert Report of Gregory M. McCormack, 10/14/2011 (Weatherford) (hereinafter "McCormack Report") at 21 ("The bottomhole barrier was never verified"); Medley Report (M-I) at 23 ("[T]he negative test should not have been considered successful").

[43] BP's *Deepwater Horizon* Accident Investigation Report (hereinafter "Bly Report") at 10, 31; Transocean Report at 30 (citing BP Investigation Team Interview of Don Vidrine, April 27, 2010; BP-HZN-MBI00021406-19; Data Logs, April 15−20, 2010; and Stress Engineering Services Inc., Hydraulic Analysis of Macondo #252 Well Prior to Incident of

and Transocean were correct in concluding that the Macondo well had passed the test and that BP and Transocean were thus justified in proceeding to underbalance the well.

The experts offer different explanations as to why the kill line pressure did not increase along with the drill pipe pressure during the negative pressure test.[44] This is largely irrelevant. The critical point is that the pressure significantly increased during the test, and thus well integrity had not been established. Given the results of the test, it was reckless for BP and Transocean to proceed to underbalance the well, as explained in my Opening Report.

This conclusion is not affected by the varying explanations as to why the kill line pressure did not increase along with the drill pipe pressure. With regard to the experts who attribute the lack of flow in the kill line to a closed valve or hydrostatic pressure in the kill line, if they are correct this just further reflects that the test failed and should not have been deemed a success (because this would reflect further errors in the negative pressure test by BP and Transocean, as during the negative pressure test the kill line valve was supposed to be open and hydrostatic pressure was supposed to have been removed so that the well could be tested for leaks). Similarly irrelevant is BP's expert William Grace's suggestion that when the kill line pressure was being monitored the well was not underbalanced and that is why the kill line pressure did not rise.[45] Not only do I disagree with

---

April 20, 2010, April 27, 2011) ("Post-incident analysis shows that the well was likely in communication with the formation."). The reports prepared by the federal government reach the same conclusion. JIT Report at 93; Deep Water: The Gulf Oil Disaster and the Future of Offshore Drilling, Report to the President at 109.

[44] *See e.g.* Expert Report of L. William Abel, 10/17/2011 (Cameron) (hereinafter "Abel Report") at 13 (opining that heavy lost circulation material restricted kill line flow); Expert Report of Donald J. Weintritt, P.E., LA and TX (Retired), 10/17/2011 (Halliburton) (hereinafter "Weintritt Report") at 21 (the spacer that BP and MI-SWACO decided to use—including the Form-A-Set AK and Form-A-Squeeze to avoid hazardous waste site costs—likely plugged the kill line); Azar Report (BP) at 47 (opining that closed kill line valve likely); Bourgoyne Report (BP) at 63 (opining that the reason kill line failed to flow is unknown); Medley Report (M-I) at 20-21 (opining that hydrostatic pressure prevented kill line flow); Barnhill Report (TO) at 28 (opining that plugging or hydrostatic pressure blocked kill line flow).

[45] *See* Grace Report (BP) at 17 ("In my opinion, the well was not underbalanced during the time the Kill Line was monitored").

Mr. Grace, but more importantly if he were correct, this would also further reflect that the test was a failure and should not have been deemed a success, because as BP designed the test, the well was to be underbalanced during the test so that the well could be checked for leaks.[46]

Again the critical point is that the results of the negative pressure test did not establish well integrity and thus BP and Transocean absolutely should not have proceeded to underbalance the well. The resulting blowout is conclusive proof that well integrity had not been established by the negative pressure test.

---

[46] Given the way BP designed the negative pressure test, BP sought to underbalance the well during the test. Thus, if the well was not underbalanced during the test (a suggestion with which I disagree), BP and Transocean failed to perform the test correctly and the test should have been deemed a failure, not a success. Furthermore, to the extent Mr. Grace is trying to suggest that the well was not flowing during the negative pressure test, I strongly disagree. The underbalanced state of the well and the flow into the well during the test is reflected by several pieces of evidence: (a) the high pressure readings shown on the drill pipe pressure gauge; (b) the significant quantities of seawater that were repeatedly bled off to bring the pressure back to zero; and (c) the fact that the drill pipe pressure, approximately 1400 psi, is equivalent to what one would expect as a result of pressure from the formation when underbalancing the well, as noted by another one of BP's expert reports, Bourgoyne Report at 63 (calculating expected drill pipe pressure based on measured pore pressure). I disagree with Mr. Grace's suggestion that the 1400 psi pressure increase seen was a U-tube effect of spacer with lost circulation material (LCM) below the BOP. This is improbable. A 1400 psi pressure differential would require over 3600 feet of the 16 ppg spacer with lost circulation material — a height that would more than fill the 3300 feet annulus between the drill pipe and the casing below the BOP. I am unaware of any expert who has concluded that this amount of spacer remained in the annulus below the BOP. Moreover, if the well was merely hydrostatically out of balance during the negative pressure test, I would not expect pressure on the drill pipe to build up gradually, as it did between 8:00 PM and 8:32 PM, after the leak past the BOP annular preventer had been stopped. The gradual build-up of drill pipe pressure between 8:00 PM and 8:32 PM is a pressure response that would be expected if the well was in communication with the reservoir. If the well was merely in a hydrostatically imbalanced condition, the pressure response would be much more sudden, if not instantaneous. Regardless, Mr. Grace's attempted explanations do not in any way justify BP and Transocean's declaring the negative pressure test a success and proceeding to underbalance the well. The pressure increases seen undeniably required that they not proceed with underbalancing the well. After-the-fact hypotheses (that were not relied upon during the test) do not justify BP and Transocean's declaring the test a success and thus underbalancing the well. The fact that the blowout occurred indisputably establishes this.

Lastly, while BP's experts acknowledge that BP misinterpreted the negative pressure test,[47] some of BP's experts appear to suggest that the negative pressure test was not the direct cause of the catastrophe. I strongly disagree. A blowout was a known or reasonably foreseeable risk of reckless disregard of the negative pressure test. On the other hand, that there would be reckless disregard of the negative pressure test was not reasonably foreseeable to contractors like Halliburton and Sperry.

The direct cause of the loss of well control and subsequent blowout was BP and Transocean's reckless disregard of the negative pressure test (which is discussed more fully in Section VI below) and, despite the failed test, their proceeding to underbalance the well per BP's temporary abandonment plan. It is also important to note again here that BP could have designed a much safer temporary abandonment plan in which the well would not be left in an underbalanced state, but instead would be shut-in balanced to avoid the risk of hydrocarbons coming up the well. As explained in my Opening Report, temporary abandonment of a well, including the Macondo well, does not require leaving the well underbalanced.[48]

V. The Float Collar: As Explained By Experts For The Other Parties, With The Sole Exception Of BP And Weatherford, BP Failed To Convert The Float Collar To Shut Its Valves To The Shoe Track Without Damage, Allowing The Blowout To Occur. Any Contrary Suggestion By Experts For BP And Weatherford Is Unsupported By The Evidence.

All the parties whose experts have considered BP's attempted conversion of the float collar share my opinion that BP failed to convert the float collar without damaging it.[49] This conclusion is supported by the fact

[47] Grace Report (BP) at 17; Azar Report (BP) at 47; Bourgoyne Report (BP) at 62)

[48] Beck Report at 90-91.

[49] Barnhill Report (Transocean) at 4, 13, 18-19; Macondo Engineering, Operations and Well Control Response, 09/23/11 at 19-20; Review of the Macondo #1 9-7/8" x 7" Production Casing Cementation Operation, by Ian A. Frigaard, 10/17/11 (Cameron) (hereinafter "Frigaard Report") at 16, 29; Expert Report of Kevin Trahan, 10/17/2011 (Cameron) (hereinafter "Trahan Report") at 17-19; Benge Report (USA) at 26-28; Expert Report of John P. Hughett, P.E., 10/17/2011 (hereinafter "Hughett Report") (Halliburton) at 34.

that BP's failed negative pressure test showed the well was leaking and by the prevailing view to date that the flow path of the blowout was up the shoe track through the float collar.[50] This conclusion is further supported by evidence showing that BP knew "something blew" during its conversion attempts.[51]

Only BP and the float collar manufacturer Weatherford suggest that the float collar converted or may have converted.[52] I disagree.[53] The absence of observed backflow after pumping the cement does not establish that the float valves converted without damage, as even some of Weatherford's experts acknowledge.[54] Moreover, not one of BP's or Weatherford's experts can reconcile a flow path up the shoe track and through the float collar with a non-damaged, properly converted float collar.

As explained in my Opening Report, the float collar installed in the Macondo well would have served as a temporary barrier and held back fluid flow if properly converted and undamaged.[55] Although the float collar was not intended to act as a permanent barrier, the post-blowout testing performed by Stress Engineering for both BP and Transocean confirmed that, if properly converted and undamaged, it would have acted as a

---

[50] While the prevailing view to date is that the flow path was up the shoe track, data recorded by BP during kill operations is inconclusive. Depo. Ex. 3005 at BP-HZN-2179MDL01591521. BP modeled three different flow paths, two up the casing and one through a breach in the casing near a crossover at 12,487 feet. None of these assumed flow paths fit the observed data, yet no additional modeling appears to have been conducted to determine an exact flow path. *Id.* Nevertheless, it thus appears that BP acknowledged possible damage to the long string in modeling flow through a breach in the casing.

[51] Depo. Ex. 2584 at BP-HZN-MBI00129068; Transocean Report at 52.

[52] Expert Report of Brent J. Lirette on Behalf of Weatherford U.S., L.P., 10/17/2011 (hereinafter "Lirette Report") at 2, 48, 57; Calvert Report (Weatherford) at 8; McCormack Report (Weatherford) at 3-4, 13-17; Expert Report of Marion M. Woolie, 10/14/2011 (Weatherford) (hereinafter "Woolie Report") at 12; Sabins Report (BP) at 84.

[53] It is worth noting that not all of the experts retained by BP and Weatherford insist that the float collar must have converted. Weatherford's expert David Calvert merely says that conversion *may* have occurred. Calvert Report (Weatherford) at 10.

[54] Calvert Report (Weatherford) at 10; *see also* McCormack Report (Weatherford) at 18.

[55] Beck Report at 79.

temporary barrier by preventing flow at the differential pressures seen in the Macondo well.[56] Additionally, in the way BP configured the negative pressure test for the Macondo well, the float collar was tested as a temporary barrier in combination with the cement, as explained in my Opening Report.[57]

Also as discussed in my Opening Report, instead of following Weatherford's published instructions and real time guidance regarding the float collar, BP ignored Weatherford's advice and used nine brute force attempts to try to convert the float collar.[58] These high pressure attempts likely damaged the float collar, possibly ejecting the ball from the auto-fill tube.[59] The majority of parties whose experts have considered this issue agree with my conclusion on this point.[60]

Certain experts retained by Weatherford discount the possibility that the ball was ejected. But their opinions fail to account for the possibility of obstructions, such as barite or other debris, which could have held the auto-fill tube in place. As all of the experts retained by Weatherford acknowledge, the auto-fill was used in the float collar to hold open its valves to help reduce surge pressures, but providing an opening for debris to enter and jam the float collar.[61] BP's high pressure attempts to clear such debris likely damaged the float collar and prevented it from performing as it would have if it had been properly converted and undamaged. The auto-fill float collar is a mechanical device and thus susceptible to failure and damage.

On the other hand, the following photograph of an auto-fill float collar like the one used in the Macondo well shows that the float collar's two

---

[56] Lirette Report (Weatherford) at 42-44; Beck Report at 79.

[57] Beck Report at 93.

[58] Beck Report at 67-72.

[59] Weatherford advised the crew that the ball could be ejected without conversion at a pressure of around 1,300 psi. This advice was confirmed with the mechanical testing conducted by Stress Engineering for Transocean. Beck Report at 70, 73-74.

[60] Frigaard Report (Cameron) at 29; Trahan Report (Cameron) at 18; *see also* Barnhill Report (Transocean) at 19.

[61] Lirette Report (Weatherford) at 19; Calvert Report (Weatherford) at 7; McCormack Report (Weatherford) at 9-11 Woolie Report (Weatherford) at 12.

check valves are a stout piece of equipment for holding back fluid flow, if they are properly closed and not damaged in the conversion process:

Lirette Report (Weatherford) at 9, Fig. 5B. It is not surprising that the backpressure test conducted by BP established that the float collar could withstand very high pressures (5000 psi), as designed.[62]

In sum, as discussed in my Opening Report, BP first failed to safely and properly convert the float collar at the safest time and next failed to repair the damaged float collar when it had the opportunity to do so. These unreasonable actions by BP, followed by its reckless disregard of the negative pressure test, led to the blowout.[63]

[62] Lirette Report (Weatherford) at 43; Beck Report at 79.

[63] Beck Report at 79.

VI. Unnecessary Risks: BP Should Have Been On Heightened Alert In Conducting The Negative Pressure Test Because Prior To That Critical Test BP Knowingly Designed, Drilled, And Operated The Macondo Well In An Unnecessarily Risky Manner For Financial Reasons.

A. BP failed to provide a safe drilling margin, instead drilling an unstable well that unnecessarily necessitated lower density cement such as foamed cement.

As discussed in my Opening Report and below, to the extent there were problems with the downhole performance of cement on the Macondo well, those problems are attributable to decisions made by BP.[64] Further, while I am not a cementing expert, it is my opinion that if BP had managed its drilling margin more effectively it could have avoided altogether the need to lower the cement density and, if BP had not created the need for a lower cement density, it would not necessarily have used foamed cement.

BP's well design, which called for unreasonably narrow drilling margins in the open hole section of the well below the bottom-most casing shoe, necessitated lowering the density of the cement, which can be accomplished by nitrogen foaming. The narrow drilling margins in the well design caused BP to be concerned about the equivalent circulating densities created when heavy mud was pumped out of the reamer shoe and up the annulus. Specifically, high pump pressures would be required to place the cement and mud into the annulus between the formation and the long string production casing, which would in turn apply high pressures to the fragile formations at the bottom of the hole.

In view of the narrow margins in the Macondo well, it was BP's risky well design that created the need for lower equivalent circulating densities and thus a lower density cement (*e.g.,* foamed cement). The nitrogen used to "foam" the cement reduced the density of the cement, thereby lowering the equivalent circulating density.

As discussed in my Opening Report, the prudent course of action by BP would have been to repair the bottom of the well, thereby increasing the drilling margin to a safe level before attempting to cement the final pay zones. Extra cement and steel casing would have isolated and reinforced

[64] Beck Report at 79-85; *see also* § VII below.

certain zones, and then lighter mud weights that produced lower equivalent circulating densities could have been used to drill to the bottom pay zone. The use of a liner as opposed to a long string would have further reduced the equivalent circulating densities. These safer alternatives would have allowed the bottom of the well to be cemented with standard, unfoamed cement.[65]

The Plaintiffs' expert Mr. Pritchard agrees with my opinion that that alternative designs were available and that BP's use of improperly balanced mud weights placed the cement job at risk:

> 2. When BP set its 9-7/8 inch casing approximately 1,000 ft above the reservoir, BP then pumped copious amounts of loss circulation material (LCM), and purposefully compromised its cement job, to avoid additional losses. BP should have chosen to set a cement plug, and run another casing liner above the top of the new cement plug, which would have allowed for BP to re-enter the reservoir with a proper balanced mud weight. This would have required days of rig time, cost more money, and required another liner, further reduced hole size, but also would have provided a safe at-balance wellbore condition to conduct logging, casing running and non-compromised cementing operations. Instead, BP chose to save the time and money, and took the risk to its cement job.

Pritchard Report at 12 (highlighting added).

Although safer alternatives were available, BP chose not to remedy the narrow drilling margins in the Macondo well. This led to its use of a light, foamed cement slurry to reduce equivalent circulating densities and potential damage to the sensitive hydrocarbon-bearing formations at the bottom of the well. Again, the Plaintiffs' expert agrees with me:

> 1. BP chose to use a long string, rather than a liner. In its MOC, BP determined that using the long string (9-5/8" x 7" Production casing), as opposed to a liner, would save BP $7-$10 million, yet could create a loss of circulation problem during cementing, requiring nitrified cement to reduce density and ECD. It chose to save the money, and accept the risk to its cement job.

[65] Beck Report at 36-38; *see also, e.g.*, Expert Report of Sam Lewis, Ph.D. on Cement: Chemistry, Formulation, Design, and Laboratory Testing, 10/17/2011 (Halliburton) (hereinafter "S. Lewis Report") at 16-17 (BP's use of foam cement "reduce[d] the risk of fracturing the formation while still allowing the use of a long string production casing string").

Pritchard Report at iv, ¶ 1 (highlighting added).

The obvious question here is why BP chose not to remedy the narrow drilling margins in the well. The answer is that doing so would have required that multiple liners be set in the well, and each of the liners would have required a separate cement job. This would cost BP both time and money—resources that BP was likely unwilling to part with for a well that was already millions of dollars over-budget and significantly behind schedule.[66] Consequently, BP chose the riskiest path in the interest of saving time and money.

B. BP incorrectly suggests that it was free to ignore the uppermost hydrocarbon-bearing zone because it may not have been "producible" from a royalty standpoint. This suggestion shows a disregard for safety.

As discussed in my Opening Report, BP's well design failed to achieve proper zonal isolation—which is critical because proper well design must ensure the isolation and containment of hydrocarbon-bearing zones—because BP misidentified and ignored the uppermost hydrocarbon-bearing zone in the well (the M57B zone).[67] Now, as discussed in Section III above, BP suggests that, because the M57B zone may not have been "producible" in the royalty context, BP was justified in ignoring the zone.[68] BP is wrong. As also discussed in Section III above, the MMS regulation in question (30 C.F.R. § 250.421) is directed at safety, not producibility from a royalty standpoint.

Furthermore, there are many factors that control the "producibility" of a reservoir, one of them being thickness. Some zones may not be deemed "producible" in the royalty context, yet may be virtually identical in regard to other significant properties such as porosity and hydrocarbon saturation. Thinner zones such as the M57B zone can be capable of delivering significant volumes of hydrocarbon to a well bore over a short period of time and for safety need to be cemented and isolated just the same as a

---

[66] BP-HZN-MBI-00125958; BP-HZN-MBI00192549; BP-HZN-MBI00192552; BP-HZN-MBI00192559. According to CCR, BP was $58 million over budget at that time. CCR at 247.

[67] *See* Beck Report at 47-51.

[68] Schoennagel Report at 27.

"producible" wellbore from the royalty standpoint. By ignoring the existence of the M57B zone, BP once again increased risk in the interest of saving time and money. Identification of hydrocarbon bearing formations in open hole sections of the well is critically important for managing safety, but BP went with the riskier, less costly option of ignoring the existence of the M57B zone.

C. BP unreasonably disregarded Halliburton's recommendation of at least twenty-one centralizers, thereby likely causing channeling.

After reviewing the other expert opinions regarding centralization, I have determined that the following points discussed in § VII.B of my Opening Report are not in dispute:[69]

- Inadequate centralization in the Macondo well increased the risk of channeling;[70]
- Halliburton recommended at least twenty-one centralizers to BP;[71]
- Based on Halliburton's recommendation, BP had fifteen additional centralizers flown overnight to the rig so that BP had a total of twenty-one centralizers available for use;[72]
- BP placed only six centralizers in the well;[73]

[69] *See* Beck Report at 53-60 (§ VII.B).

[70] Barnhill Report (Transocean) at 19-20; Frigaard Report (Cameron) at 6, 23-25; *see also* Depo. Ex. 4842 at 6 (cementing expert Dr. Robert Beirute cautioning against not running centralizers "[o]r run just a few" otherwise it would result in a poor cement job); Pritchard Report (Plaintiffs) at 19; Trahan Report (Cameron) at 25.

[71] Sabins Report (BP) at 71-72; CCR at 83; BP-HZN-BLY 61327; HAL_10604; HAL_10608; HAL_10713; Frigaard Report (Cameron) at 6; Pritchard Report (Plaintiffs) 19; Trahan Report (Cameron) at 25.

[72] Sabins Report (BP) at 71-72; CCR at 83-84; BP-HZN-BLY 61327; Tr. of Telephone Interview of J. Gagliano, 6/11/2010 at 50-52; Bly Report at (BP) 64 ("The investigation team determined . . . that the decision to ship 15 additional centralizers was made as a result of the OptiCem™ modeling on April 15, 2010.").

- BP did not consult Halliburton or Weatherford (its centralizer supplier) in regard to its decision to place only six centralizers in the well;[74]
- BP did not ask Halliburton to generate an OptiCem™ model predicting the risks associated with placing only six centralizers in the well;[75]
- Halliburton, using its OptiCem™ software, predicted a risk of channeling and a SEVERE gas flow potential in the event that BP placed only 7 centralizers in the well and informed BP of this prediction;[76] and
- BP did not follow its internal management of change (MOC) process in connection with its decisions regarding centralization of the well.[77]

Two of BP's experts nonetheless seek to justify BP's decision to use only six centralizers.[78] They attempt to do so based on three unsupported and incorrect claims.

---

[73] CCR at 86; Bly Report at 63; BP-HZN-BLY 61225; Tr. of the Joint United States Coast Guard Minerals Management Service Marine Board of Investigation into the Marine Casualty, Explosion, Fire, Pollution, and Sinking of Mobile Offshore Drilling Unit Deepwater Horizon, With Loss of Life in the Gulf of Mexico 21-22 April 2010 (hereinafter "USCG/MMS Investigation"), 7/22/10 (J. Guide Testimony) at 374; Frigaard Report (Cameron) at 6; Pritchard Report at 19; Trahan Report at 25.

[74] Beck Report at 56; BP's expert Fred Sabins attempts to justify BP's use of only six centralizers by citing to various testimonies by BP's contractors including Halliburton, Dril-Quip, and Weatherford. Sabins Report at 72. But such testimony is irrelevant. BP's decision to use only six centralizers was unilateral without involving any of its contractors. BP's overnight delivery of the fifteen additional centralizers also shows that BP deemed additional centralizers necessary for the operation.

[75] Beck Report at 56.

[76] CCR at 86; Bly Report at 64; BP-HZN-MBI 128708-756 at BP-HZN-MBI 128739; Tr. of Telephone Interview of Jesse Gagliano, 06/11/10 at 41, 44-45; Trahan Report at 25. My Opening Report explained that, had BP disclosed the existence of the M57B zone to Halliburton, Halliburton's OptiCem™ simulation would have predicted a CRITICAL gas flow potential for the well (as opposed to a SEVERE gas flow potential). I note that BP has made no effort to explain or justify its withholding of such pertinent well information from Halliburton. Beck Report at 57.

[77] Bly Report at 64; Depo. Ex. 6291.

First, BP's experts Fred Sabins and J.J. Azar suggest that BP's use of six centralizers was an acceptable "engineering decision" and that the additional fifteen centralizers recommended by Halliburton for use in the well were not necessary or suitable.[79] I disagree. To start, BP's so-called "engineering decision" to use only six centralizers was in reality a poor procurement decision. As discussed in my Opening Report, BP failed to timely procure a sufficient quantity of centralizers for the well, leading to a shortage of centralizers on the rig.[80] Regarding whether the fifteen additional centralizers were necessary, BP's experts fail to provide any explanation as to why, if that was not the case, BP went ahead and procured them at the last minute based on Halliburton's advice. BP's experts' claim that the fifteen centralizers BP procured at the last minute were not suitable is similarly inexplicable given that BP's own Bly Report concludes that the fifteen additional centralizers in question "were in fact the correct centralizers" for the well.[81]

Second, BP's expert Mr. Sabins suggests that Halliburton recommended that BP proceed with the cement job using only six centralizers.[82] I disagree. The decision to place six centralizers in the Macondo well was BP's and BP's alone. BP engineer Gregg Walz made this clear when he testified before the USCG/BOEM Board of Investigation:

---

[78] BP's expert Mr. Sabins references Displace 3D modeling conducted after the blowout. Sabins Report (BP) at 73-74. Because it was conducted after the blowout, it could not have informed BP's decision to use only 6 centralizers and thus is not relevant to whether that decision was reasonable when made. Mr. Sabins appears to agree, as he does not assert that this post-blowout modeling influenced BP pre-blowout.

[79] Azar Report (BP) at 38 (opining that BP's use of six centralizers "is consistent with sound engineering principles"); *see also* Sabins Report (BP) at 72.

[80] Beck Report at 54-55.

[81] Bly Report at 64.

[82] Sabins Report (BP) at 34 (omitting events on April 15, 2010 where Halliburton's Gagliano conducted multiple OptiCem™ simulations with BP engineers which led BP to have fifteen additional centralizers flown to the rig).

4 A Sir, we had our plans in place.
5 The centralizers that we had available --
6 You know, the role of drilling, oftentimes
7 we have to make judgments between
8 recommendations from one company versus
9 other risks. We have to weigh out, because
10 what's good for one may not be better for
11 another set of criteria.
12 We made that assessment, that
13 judgment that we were incurring other risks
14 by using those, so when we realigned the
15 centralizers to get to -- Because

Tr. of USCG/MMS Investigation, 10/7/2010 AM (G. Walz Testimony) at 187:20-188:15. Additionally, as discussed in my Opening Report, BP never informed Halliburton of its decision to use only six centralizers in the well and ignored an email from Halliburton's Jesse Gagliano on the subject.[83] When Gagliano learned of BP's decision to use just six centralizers, he was "frustrated" and concerned that "the cement job would require remedial work,"[84] but he knew "that was [BP's] decision."[85] BP's Gregg Walz confirmed this when he testified that BP was fully aware and accepted the risk that a remedial cement job would be required due to inadequate centralization and that BP had "contingency plans" in place.[86]

Third, BP's expert Dr. Azar asserts that Jesse Gagliano did not warn BP of inadequate centralization.[87] Again, I disagree. As discussed in my Opening Report, BP Operations Engineer Brett Cocales and Drilling

[83] Beck Report at 56; Tr. of USCG/MMS Investigation, 8/24/2010 (J. Gagliano Testimony) at 259:6-9; G. Walz Depo., 4/21/11 at 181:16-182:7; CCR at 106; BP-HZN-MBI 128489.

[84] Telephone interview of Jesse Gagliano 6/11/2010 at 8.

[85] Telephone interview of Jesse Gagliano 6/11/2010 at 41, 95.

[86] Tr. of USCG/MMS Investigation, 10/7/2010 AM (G. Walz Testimony) at 183:21-184:7, 187:10-19 ("When we went to the direction to realign to the six [centralizers],…We had the contingency plans in place in the event something went wrong.").

[87] Azar Report (BP) at 37-38.

Engineering Team Leader Gregg Walz reviewed and considered an April 18 email from Halliburton's Gagliano that included the OptiCem™ report warning of the risks associated with using just six centralizers.[88] But both ignored the warnings. Rather, based on their belief that Halliburton would have an opportunity to perform remedial cementing if the primary cement job channeled, they decided that BP's poor centralization would "probably be fine."[89]

I similarly disagree with Dr. Azar's suggestion that the inadequate centralization was irrelevant to the blowout.[90] Lack of annular zonal isolation through inadequate centralization causing channeling creates a risk of flow up and down the annulus, and, under the prevailing view to date that the flow was down the annulus and up the shoe track, likely did enable the blowout.

BP did not conduct itself as a prudent well operator when it failed to timely procure sufficient centralizers to properly centralize the casing, ignored Halliburton's recommendation of at least twenty-one centralizers, and installed only six centralizers.

D. BP imprudently chose a long string design, increasing the risk of cement contamination, fracturing, and annular flow.

Some of BP's experts suggest that BP's use of a long string production casing was appropriate.[91] I disagree. A long string production casing might make sense for certain wells in the Gulf of Mexico, but, for the reasons discussed in my Opening Report, that was not the case for the

---

[88] Beck Report at 56-57.

[89] BP engineers were aware of the potential channeling and gas flow potential as a result of inadequate centralization as early as April 15 and accordingly ordered the additional 15 centralizers. *See* B. Cocales Depo., 04/26/11 at 688:15-19 and 858:10-14; Depo. Ex. 1517 at BP-HZN-2179MDL00033080; Tr. of USCG/MMS Investigation, 10/7/2010 AM (G. Walz Testimony) at 183:21-184:7, 187:10-19 ("When we went to the direction to realign to the six [centralizers],…We had the contingency plans in place in the event something went wrong.").

[90] Azar Report (BP) at 39 (opining that "any failure relating to eccentricity caused by a lack of centralization would have resulted in flow up the annulus, not the shoe track.")

[91] *See, e.g.*, Review of the Production Casing Design for the Macondo Well, Expert Report by David Lewis, 10/17/2011 (BP) at 5; Azar Report (BP) at 34-35; Sabins Report (BP) at 69.

Macondo well.[92] BP selected the risky long string design (over the safer liner design) based on its conclusion that doing so would result in "the best economic case" for the Macondo well,[93] once again prioritizing economics ahead of safety. I am not alone in my conclusions that BP's use of a long string instead of a liner placed the cement job at risk and that BP's motivation for doing so was money. The Plaintiffs' expert Mr. Pritchard agrees with me on both issues.[94]

E. BP unreasonably chose not to circulate bottoms up or to adequately condition the wellbore for cement placement, increasing the risk of channeling and contamination.

As discussed in my Opening Report, BP should have adhered to the widely recognized good practice of circulating bottoms up prior to cementing.[95] The majority of the experts who have also addressed this agree with my conclusion, including at least Calvin Barnhill (Transocean), Dr. Robert Bea and Dr. William Gale, Jr. (Plaintiffs), Glen Benge (USA), Ian Frigaard (Cameron), David Pritchard (Plaintiffs), and Kevin Trahan (Cameron).[96] BP appears to stand alone in suggesting that a bottoms up circulation prior to the cement job was not necessary.[97]

BP's expert Dr. Azar suggests that BP's bottoms up circulation on April 16, 2010, three days prior to the cement job, was sufficient. I

---

[92] Beck Report at 39-46.

[93] Depo. Ex. 2659 at BP-HZN-MBI00143259.

[94] Pritchard Report (Plaintiffs) at iv, ¶ 1.

[95] *See* Beck Report § VII.G.

[96] Barnhill Report (Transocean) at 20 ("The volume of SBM….did not total up to a complete bottoms up volume for the well."); Bea-Gale Report at xviii ("Refusing to circulate full bottoms up prior to cement job" is one the failures of BP on Macondo); Benge Report (USA) at 22 ("The pre-job circulation volume on the Macondo well was very small and did not approach bottoms up."); Frigaard Report (Cameron) at 7 ("More circulation would have better conditioned the drilling mud for displacement."); Pritchard Report (Plaintiffs) at 18 (BP's choice to forego a bottoms up circulation "increased the likelihood that the cement job would fail"); Trahan Report (Cameron) at 20 ("Failure to circulate 'bottoms up' volume (or anywhere close to it) prior to pumping cement" increased the risk the risk of contamination).

[97] Sabins Report (BP) at 70-71; Azar Report (BP) at 35.

disagree. Dr. Azar's suggestion presumes that the sole purpose of bottoms up circulation is to remove cuttings from drilling operations. But, as explained in my Opening Report, circulating the full annular volume prior to cementing is prudent for a number of reasons. First, gelled mud likely accumulated in the wellbore over the three-day period between April 16 and April 19, and a bottoms up circulation would have cleaned the wellbore of gelled mud prior to cementing, reducing the risk of cement contamination, channeling, and lost circulation. Second, a bottoms up circulation is important when, as was the case here, hydrocarbons were observed to be seeping into the wellbore during logging operations.[98] This fact alone dictated that the well should have been fully circulated prior to cementing.[99] BP's expert Dr. Azar did not address these purposes for bottoms up circulation and my opinion remains unchanged that BP should have performed bottoms up circulation to properly clean and condition the well prior to the cement job.

BP's expert Mr. Sabins suggests that Halliburton was involved in the decision to forego bottoms up circulation prior to the cement job. The evidence that I have reviewed indicates otherwise: namely, prior to the cement job, Halliburton's Nathaniel Chaisson suggested at least one full bottoms up but was told by a BP well site leader that a lower volume would be pumped.[100] Also, Mr. Chaisson noted in his April 18 job log that the volumes and pump rates listed were "as per co. man," reflecting that the company man, BP, had made the decision to not circulate bottoms up.[101]

The only acceptable event that would preclude a full circulation of the wellbore prior to cementing is a loss of circulation. BP's experts do not suggest that there was any lost circulation event during the bottoms up circulation prior to the cement job, and accordingly my opinion remains unchanged that BP should have adhered to the good practice of circulating

---

[98] BP-HZN-2179MDL3541-45 at BP-HZN-2179MDL3543; Depo. Ex. 3188 at BP-HZN-BLY0061515.

[99] Beck Report at 77.

[100] CCR at 91; N. Chaisson Depo. 03/17/11 at 704:11-705:14 ("[W]e definitely were going to pump this volume at this rate as dictated by [BP's] Bob Kaluza."); Tr. of USCG/MMS Investigation, 8/24/2010 (N. Chaisson Testimony) at 437:3-438:8.

[101] CCR at 91; BP-HZN-CEC 21448; Tr. of USCG/MMS Investigation, 8/24/2010 (N. Chaisson Testimony) at 437:3-438:8.

bottoms up prior to cementing.[102]

F. BP unreasonably canceled the cement bond log previously scheduled with Schlumberger.

As discussed in my Opening Report, BP should have conducted a cement bond log. A cement bond log would have permitted BP to accurately determine the top of cement and would have yielded information as to the general quality of the zonal isolation achieved by the cement placement. This would have in turn permitted BP to make a more accurate assessment of the annular cement as a potential barrier to flow. Instead of conducting a cement bond log, however, BP sent the Schlumberger testing crew who was prepared to conduct the test home early.[103]

The majority of the experts who have also considered whether BP should have conducted a cement bond log agree with my conclusion, including at least Calvin Barnhill (Transocean), Dr. Robert Bea and Dr. William Gale, Jr. (Plaintiffs), Ian Frigaard (Cameron), David Pritchard (Plaintiffs), and Kevin Trahan (Cameron).[104] Significantly, BP appears to be alone in suggesting that a cement bond log was not necessary.[105]

Additionally, as discussed in Section II above, I disagree with BP's suggestion that it was justified in canceling the cement bond log because

---

[102] Note that the pre-cementing bottoms up circulation discussed here, which serves to condition and prepare the wellbore for the cement job, is distinguishable from the circulation of spacer and other fluids during the cement job, which serves to isolate the cement from possible contaminants. Given this distinction, any reference by BP's expert Mr. Sabins to Displace 3D modeling in regard to spacer is irrelevant to pre-cement bottoms up circulation.

[103] Beck Report at 87-88.

[104] Barnhill Report (Transocean) at 21 ("[T]he CBL would have been able to see if the top of the cement was in the right general area and the general quality of the cement bonding from the top of the cement down to the area of the float collar."); Bea-Gale Report (Plaintiffs) at xviii (failure to run a cement bond log is one of the "knowing failures of the BP Macondo team"); Frigaard Report (Cameron) at 29 ("For all these reasons it would have been advisable to evaluate the cement job further with some form of logging (e.g. a cement bond log) before proceeding."); Pritchard Report (Plaintiffs) at 19; Trahan Report (Cameron), 10/17/11 at 29 ("Had a CBL been run at either point, in all likelihood the blowout would have been prevented.").

[105] Sabins Report (BP) at 78-80; Azar Report (BP) at 39-40.

Halliburton did not indicate that it was needed.[106] As BP itself correctly acknowledges, BP (specifically, its drilling engineers) was responsible for making and did in fact make the decision to cancel the planned cement bond log.[107] Halliburton, as BP's cementing contractor, had no input into this decision and was not part of BP's "decision tree."[108] As I have ascertained no basis for BP's decision other than its desire to save approximately eight hours of rig time by not running the cement bond log, it is apparent that BP decided not to conduct the test in the interest of saving time and money, again at the expense of safety.[109]

G. BP chose a risky temporary abandonment plan.

As explained in my Opening Report, BP failed to provide a safe temporary abandonment plan for the Macondo well.[110] Other experts have similarly concluded that BP could have and should have designed a less risky temporary abandonment procedure, including at least L. William Abel (Cameron),[111] Calvin Barnhill (Transocean),[112] Dr. Robert Bea and Dr.

---

[106] Sabins Report (BP) at 79-80.

[107] Azar Report at 39; *see also* R. Sepulvado Depo. 3/10/11 at 146:17-149:16 (testimony by BP Well Site Leader that even BP's own well site leader "does not have the discretion to make that call [on the cement bond log] unless it's within that decision tree").

[108] CCR at 94 (citing BP-HZN-MBI 143304 and BP-HZN-CEC 21665).

[109] Additionally, I find it notable that BP's experts make no mention of BP's written practices stating that a cement bond log should be run in all instances where top of cement is less than 1000 feet above the shallowest hydrocarbon zone (*i.e.,* ETP 10-60, §§ 5.3.1 and 5.3.3)[109] or of BP's failure to follow these internal standards when it canceled the planned cement bond log. BP's failure to follow these internal standards and others is explained in my Opening Report. *See, e.g.* Beck Report at 20-31.

[110] Beck Report at 12-13.

[111] Abel Report at 8-11 (opining that BP failed to set a second barrier before removing hydrostatic control during temporary abandonment and that "BP apparently decided it was more cost effective to use the DWH to set the wellhead packoff which required . . . a drill pipe depth of 8,367 feet for the plug and abandonment procedure....Yet no consideration was given to the fact that 8,367 feet is considered to be a poor position . . . if the well were to kick....").

William Gale (Plaintiffs),[113] and David Pritchard (Plaintiffs).[114]

The safer alternative to BP's plan to set the lock down sleeve as the last step in its temporary abandonment procedure would have been to set the lock down sleeve first to guard against the casing hanger seal assembly becoming unseated during the temporary abandonment procedure.[115] Most experts who have considered this issue agree, including L. William Abel (Cameron)[116] and Calvin Barnhill (Transocean).[117] BP's expert Dr. Azar appears to stand alone in suggesting that BP's plan to

---

[112] Barnhill Report (Transocean) at 1, 22-26, 42 (stating that "[t]he net effect [of BP's decisions] was to un-necessarily place the Macondo Well at risk during the TA" and opining that BP's plan "to set the cement plug in water coupled with the desire to set the LDS last using the already standing back drill pipe morphed the TA procedure into higher risk" and that BP's temporary abandonment procedure "did not have to be conducted under the level of risk it was."); *see also* Barnhill Report (Transocean) at 25 (opining that "If someone within BP had simply stepped back and considered an overview of the entire situation to include: the history of the well; coupled with the fact that adequate flow barriers, much less redundant flow barriers, had not been tested nor confirmed; further coupled with the fact that the TA operations about to be carried out would potentially significantly underbalance the well by displacing it to a significantly deeper depth than normal - other options could have been explored that would have significantly reduced the risk.").

[113] Bea-Gale Report (Plaintiffs) at xi, xviii, xxiii, 58. 73 (opining that BP did not have a risk management process for its temporary abandonment procedure and that "[r]efusing to install additional physical barriers during temporary abandonment" is one of the knowing failures of BP on Macondo).

[114] Pritchard Report (Plaintiffs) at 86 (BP's "procedures were woefully inadequate [including] [n]o details for negative pressure testing or displacement, and managing those known and previously identified risk of uncontrolled blowout").

[115] Beck Report at 91.

[116] Abel Report (Cameron) at 8-11 (opining that "BP apparently decided it was more cost effective to use the DWH to set the wellhead packoff which required…a drill pipe depth of 8,367 feet for the plug and abandonment procedure…[y]et no consideration was given to the fact that 8,367 feet is considered to be a poor position…if the well were to kick….").

[117] Barnhill Report (Transocean) at 1, 22-26, 42 ("The net effect [of BP's decisions] was to un-necessarily place the Macondo Well at risk during the TA" and opining that BP's plan "to set the cement plug in water coupled with the desire to set the LDS last using the already standing back drill pipe morphed the TA procedure into higher risk").

set the lock down sleeve last was not more risky.[118] He instead suggests that BP's decision was made "out of concern for the potential that the operations . . . could damage the LDS [lock down sleeve]."[119] As I stated in my Opening Report, however, the risk associated with the casing hanger lifting off-seat during the negative pressure test far outweighs any risk associated with damaging the lock-down sleeve as the cost to repair a damaged lock-down sleeve is marginal compared to a well control incident.[120]

In addition to setting the lock down sleeve first, BP also could have designed a much safer temporary abandonment plan under which the well would have been kept in a balanced state (as opposed to underbalancing the well as BP did) while placing a second, upper cement plug. Under this much safer alternative, the lock down sleeve would have been set first, followed by establishing well integrity by conducting both positive and negative pressure tests, and then setting a cement plug as a barrier prior to the removing of the balancing drilling mud from the riser. BP then could have shown appropriate further caution by taking the additional step, prior to setting the cement plug, of filling the well with heavy mud from the seafloor to the float collar, which would then allow the removal of the drilling fluid from the riser, without underbalancing the well—*i.e.*, the well would have been kept and left in a balanced state.[121]

BP's expert Dr. Azar suggests that BP's plan to set the cement plug at about 3,000 feet below the mudline did not increase the risk of underbalancing the well.[122] This suggestion is contrary to my view and the view expressed by most of the experts who have considered the issue of the surface plug.[123] BP's plan to set the cement plug 3,000 feet below the

[118] Azar Report (BP) at 40.

[119] Azar Report (BP) at 43.

[120] Beck Report at 91.

[121] Beck Report at 88.

[122] Azar Report (BP) at 42.

[123] Abel Report (Cameron) at 8-11 (opining that "8,367 feet is considered to be a poor position…."); Barnhill Report (Transocean) at 1, 22-26, 42 (opining that BP's "[Temporary abandonment] operations…would potentially significantly underbalance the well by displacing it to a significantly deeper depth than normal….").

mudline with displacement all the way down to there with seawater exposed the well to a much higher degree of underbalance, the consequences of which were a greater chance of failing a barrier and inducing a kick.

I also disagree with Dr. Azar's opinion[124] that BP's failure to finalize its temporary abandonment plan for the Macondo well until April 20 (the day of the blowout) was reasonable. In my opinion, BP's last-minute changes were unreasonable because they appear to have been motivated solely by BP's desire to save time and money and made at the expense of safety.[125] In attempting to suggest otherwise, Dr. Azar appears to focus selectively on BP's revisions to its plan "between April 12, 2010 and April 15, 2010," without addressing the multiple revisions made by BP between April 15 and the April 20 blowout.[126] Moreover, although Dr. Azar suggests that BP revised its temporary abandonment plan between April 12 and April 15 in response to information acquired by BP during drilling, he fails to provide any explanation whatsoever of how the differences between BP's initial and final plans could have resulted from new knowledge gained from logging the well. If anything, the results of logging operations should have placed BP on heightened alert, and all subsequent operations should have been designed to reduce the risk to "as low as reasonably practical," as required by DWOP § 3.3.1.[127] The well logs obtained by BP clearly show a massively thick high-porosity reservoir with the potential to deliver high volume flow if placed in an underbalanced condition. Accordingly, given BP's and Dr. Azar's failure to offer any credible justification for BP's multiple revisions to its temporary abandonment plan in the days just before the blowout (and ignoring BP's management of change requirements), any suggestion that BP was reasonable in waiting until April 20 to finalize its plan should be rejected.

---

[124] Azar Report (BP) at 40.

[125] In addition to the several substantive deficiencies that I and other experts have noted, BP's temporary abandonment plan was procedurally deficient. This is evidenced by the two page list of last-minute changes set forth in my Opening Report, all of which were made by BP without following its internal management of change process. Beck Report at 26-28. BP does not disagree that the management of change process was not followed for BP's various decisions in the temporary abandonment procedure.

[126] Azar Report (BP) at 40.

[127] Depo. Ex. 6121 at BP-HZN-BLY00034519 (DWOP § 3.3.1).

VII. The Cement Job: As Other Parties' Experts Agree, BP — Not Halliburton — Is Responsible For Any Failure Of The Primary Cement Job To Achieve Zonal Isolation.

The experts who have criticized Halliburton's cement design and pumping work on the Macondo well offer drastically different opinions concerning how the cement job supposedly failed to provide zonal isolation.[128] In my opinion, this lack of an accepted, cohesive theory undermines their respective views and supports my own opinion that, to the extent that there were problems associated with the downhole performance of cement on the Macondo well, any such problems were likely caused by one or more of the following decisions made by BP:

- BP's decision to inadequately centralize the well and its decision not to perform even a single bottoms-up circulation prior to the pumping of the cement, both of which likely caused channeling in the annulus;[129]
- BP's decision to use a long string production casing, which increased the risk of contaminating the cement;[130]
- BP's decision to leave light weight drilling mud in the rathole, which risked roping where the light weight mud migrates up through the heavier cement in the shoe track, forming channels in the unset cement from the reamer shoe up to the unconverted float collar;[131]

[128] *See generally* Sabins Report (BP) at 24 (cement was unstable and porous because the nitrogen formed channels that could act as flow paths for hydrocarbons); Frigaard Report (Cameron) at 20-28 (cement was contaminated by channeling and fluid swapping and was not fully set); Calvert Report (Weatherford) at 14-20 (hydrocarbons created flow channels through the shoe track cement as the cement was setting); and Trahan Report (Cameron) at 10, 19-29 (impossible to pinpoint the exact cause of cement failure, but failure was likely due to low cement volume, the low rate at which the cement was pumped, contamination, and/or movement of the cement as it set).

[129] Beck Report at 53, 77.

[130] Beck Report at 39.

[131] Beck Report at 82.

- BP's decision not to wait on cement for at least the industry accepted twenty-four hours before performing additional rig operations, which, as other parties agree, risked interfering with the cement setting;[132]
- BP's decision to cancel its planned cement bond log, which, as recognized by other parties, could have put BP on notice of problems with the cement job;[133] and
- BP's decision to apply pressures far in excess of those recommended by the manufacturer when attempting to convert the float collar, which may have caused the entire shoe track to separate from the float collar and put the cement job at risk.[134]

All of the foregoing decisions, any one or more of which put the cement job at risk of failing, were made by BP and BP alone. Any consequences that resulted from these decisions are thus due to BP and not attributable to Halliburton.

Lastly, in addition to BP's decisions listed above, BP's failure to convert the float equipment without damaging it also could have caused problems with the cement job.[135] This failure to convert the float equipment without damage allowed u-tubing to occur, which in turn would have extended the time required for the shoe track cement to set.[136] My opinion in this regard is shared by Cameron's expert Mr. Trahan.[137]

---

[132] Beck Report at 85; Pritchard Report (Plaintiffs) at 33 (BP's decision to perform the positive pressure test only 10 hours after pumping the cement plug "recklessly increased the risk of compromising the cement job"); Trahan Report (Cameron) at 14 (an unconverted float collar can "prevent cement from setting up because of ongoing movement"); *see also* S. Lewis Report (Halliburton) 45-47; Expert Report of David Bolado, 10/17/2011 (Halliburton) at 38-41; Hughett Report (Halliburton) at 35-39.

[133] Beck Report at 87; Pritchard Report (Plaintiffs) at 33; Trahan Report (Cameron) at 29.

[134] Beck Report at 83-85.

[135] Beck Report at 62.

[136] Sam Lewis, a Halliburton cement expert, has concluded that the cement pumped by Halliburton, if left undisturbed, likely would have been set at the time BP and Transocean lost control of the well. S. Lewis Report (Halliburton) at 45.

[137] *See* Trahan Report (Cameron) at 14.

VIII. Cement Remediation: The Only Reasonably Foreseeable Consequence Of A Failed Cement Job Is A Cement Repair Job, Which BP Did Not Allow For Because It Disregarded The Results Of Its Negative Pressure Test.

If BP had correctly interpreted the results of the negative pressure test, it would have recognized that zonal isolation of the hydrocarbon bearing zones had not been achieved and that corrective steps were necessary. At that point, the only reasonably foreseeable consequence of the failure to achieve complete zonal isolation through the primary cement job would have been the need for cement remediation (*e.g.,* a "squeeze job"), whereby additional cement would be added.

As recognized by other experts,[138] the need for such a cement repair job would not have been a surprise. BP's well site leaders were aware that cement remediation may have been needed, as demonstrated by BP's management of change documentation from April 14, 2010.

> If losses occur during the cement job, possible cement evaluation, including remedial cement operations, dispensations, and/or MMS approvals will be required prior to performing TA operations due to a lower than required Top of Cement in the annulus. Possible hydrocarbon zones could be left exposed in the annulus with only the casing hanger seal as the single barrier for the TA. The attached decision tree addresses these options. A perf[oration] and squeeze operation could be performed to add a second barrier in the annulus.

[138] *See* Sabins Report (BP) at 73 ("[A]ny potential channeling that causes long term isolation issues can be addressed by remedial cementing."); Calvert Report (Weatherford) at 13 ("In my opinion, the failure of the negative pressure test demonstrates a failed production casing cement job in the Macondo Well. In this situation, industry standards require, and a prudent operator should insist, that remediation actions be undertaken to establish well integrity. Two possible remediation actions were to perform a squeeze job or set a bridge plug.") (emphasis added); Trahan Report (Cameron) at 29 ("The information gained by the CBL likely would have revealed issues that would have caused BP to take remedial actions. Even after the subsequent issues with the negative test used to test the integrity of the Macondo cement job, BP could have made the decision to run the CBL. Had a CBL been run at either point, in all likelihood the blowout would have been prevented.")

Depo. Ex. 2659 at BP-HZN-MBI00143259 (emphasis added). Following its failed negative pressure test, BP should have displaced the mud back into the well to return the well to balance (*i.e.,* mud weight above the pore pressure and below the fracture gradient). BP then could have proceeded to evaluate and repair the cement job. The well would have been kept balanced and hence under control and the blowout could have been prevented. Instead, BP imprudently disregarded the results of the negative pressure test, proceeded to underbalance the well, and the blowout occurred.

IX. Mudlogging: Sperry acted reasonably while monitoring the final displacement.

After reviewing the reports of the other parties to this action, I see nothing that alters my opinion that on April 20, 2010, decisions by BP, Transocean, and M-I SWACO to conduct multiple, simultaneous and non-standard operations during the final Macondo displacement frustrated any reasonable opportunity that Sperry's mudlogger, Joe Keith, had to identify the kick. As many of these reports recognize, Joe Keith was a "second set of eyes" monitoring the well, and he had access to far less information than the BP company man and the Transocean drilling crew because of decisions made by BP, Transocean and M-I SWACO.

Other experts improperly lump Joe Keith in with the Transocean drilling crew, even though Mr. Keith was kept uninformed of ongoing rig operations, and by the time the sheen test was complete soon after 9:09 PM on April, 20, the Sperry flow-out sensor was bypassed per BP's, Transocean's, and M-I SWACO's approved instructions,[139] while the drilling crew's Hitec flow-out sensor remained available to Transocean and BP. Mr. Keith could not, per BP's instructions, access the Hitec flow-out data. It is clear that BP and Transocean knew the limitations of the mudlogger's monitoring capability, yet they designed and executed a displacement that involved bypassing the pits, gas sensor, and Sperry's flow-out sensor. These same experts, while agreeing with me that the pits could have been configured in a "closed" system to allow Joe Keith to monitor the well for gains, attempt to shift the responsibility for the pits' configuration to Sperry. Sperry, however, has no authority over, or responsibility for, how the pits were configured or how the displacement was conducted. The

[139] Depo. Ex. 967; *see also* Depo. Ex. 607.

responsibility for those decisions falls squarely on BP's, Transocean's, and M-I SWACO's shoulders.

A. The Sperry mudlogger was not in the same position as BP and the Transocean drilling crew.

A common mischaracterization throughout the other parties' expert reports is the comparative position of the Sperry mudlogger relative to the Transocean drilling crew. BP's experts in particular improperly attempt to lump these individuals into a single category.[140] However, as outlined in my Opening Report, the Sperry mudlogger and the Transocean drilling crew were not on equal footing on the evening of April 20. Transocean had better information about both the well and the rig operations. In particular, not only was the Transocean drilling crew fully aware of rig operations at all times—they were, after all, directing and conducting those operations—but they could also monitor the flow-out data when they began diverting returns overboard right as it appears the well started kicking, while Joe Keith could not.[141] The drill crew's control of operations also puts them in a direct, hands-on position to be aware of ongoing operations, whereas the mudlogger sits in a small room away from the drill floor. To stay abreast of rig operations, the mudlogger must receive updates from the drilling crew.

I understand the drilling crew never once called Joe Keith on April 20, 2010.[142] Nor did the BP well site leader, the M-I SWACO compliance specialist, or drilling fluids engineer attempt to keep the mudlogger informed of any ongoing operations. In addition, the mudlogger had no ability or authority to make decisions regarding rig configuration, well control actions, displacement procedure, or whether to activate the BOP; this authority is reserved for the BP company man and the Transocean drilling crew who are all required by regulation to be certified in well control.

---

[140] *See*, *e.g.*, Bourgoyne Report (BP) at 10 and 64-66; Grace Report (BP) at 2 and 18-20; and Azar Report (BP) at 11, 44-45, and 50.

[141] Any implication by BP's experts that Joe Keith had access to Transocean's flow-out data is belied by the findings of BP's own investigative team. Bly Report at 42; S. Robinson Depo., 1/27/2011 at 348:25-349:23; *see also* TRN-INV-01824082 (E-mail relating to Transocean's investigation concluding the Sperry sensor was bypassed when diverting overboard, but the Transocean paddle sensor was not)."

[142] Tr. of USCG/MMS Investigation (J. Keith testimony), 12/7/2010 at 193:11-15.

As described in Appendix C to my Opening Report, at 9:08 PM the Transocean drilling crew shut down the pumps to conduct the sheen test. Approximately one minute later, the Sperry mudlogger, Joe Keith, conducted a flow check and visually observed flow from the well decrease and then stop. This is confirmed by the surviving Sperry flow-out data.[143] Flow either stopped because the well was not yet underbalanced, or because Transocean improperly diverted returns overboard before the sheen test was conducted. If well returns were diverted overboard prematurely, only the drilling crew would have known this; the Sperry mudlogger would reasonably have concluded that the well was secure, having just passed a successful flow check—the gold standard in kick detection. Accordingly, after Joe Keith had confirmed the well was static at 9:09 PM, he had no reason to believe any mudlogging data collected and observed up to that time indicated a kick or a need for well control.

When the displacement resumed at 9:14 PM, after the sheen test, returns were routed overboard at the bypass line to dispose of the weighted lost circulation material spacer. When BP, Transocean, and M-I SWACO decided to dump this spacer overboard, it did so knowing that it would bypass both Sperry's flow-out sensor and the *Deepwater Horizon*'s pit system, effectively blinding the Sperry mudlogger from his primary well flow kick indicators—pit gain, increased flow-out, and high gas content.[144]

While the Sperry flow-out sensor and the pits were bypassed and unavailable to monitor well flow, the Transocean Hitec flow-out sensor was still able to monitor the rate of flow out of the well.[145] Although the Sperry mudlogger had access to some Transocean data, Sperry did not have

---

[143] Exhibit 604.

[144] I understand that Transocean and BP had to approve the location for the Sperry flow-out sensor, and that Transocean and BP could have requested the sensor be moved at any time. *See*, *e.g.*, J. Keith Depo., 3/28/2011 at 175:5-176:15; K. Gray Depo., 4/15/2011 at 542:8-543:8; J. Gisclair Depo., 3/14/2011 at 103:20-105:15; and S. Clark Depo., 7/29/2011 at 209:4-210:6.

[145] *See*, *e.g.*, M. Sepulvado Depo., 5/11/2011 at 375:15-376:8; R. Sepulvado Depo., 3/10/2011 at 263:11-264:24; R. Tiano Depo., 8/25/2011 at 263:2-264:4 (Transocean flow-out sensor should have accurately transmitted flow measurements on April 20, 2010); and Bourgoyne Report (BP) at 65 ("When pumping overboard, the Sperry-Sun flow-out meter was bypassed. However, flow was passing through a second flow meter that was part of the rig sensor package.")

access to the Transocean flow-out data even though the BP company man and the Transocean drilling crew certainly did.

As described in my Opening Report, BP told Sperry's mudloggers on the *Deepwater Horizon* to use the Sperry flow-out sensor, and not the Hitec sensor.[146] The vast majority, if not all, of the kick occurred after well returns were diverted by BP and Transocean out of the mudlogger's flow and gas monitoring capability. As the flow from the well increased after the sheen test, BP and Transocean could have and should have seen a significant increase in the flow-out rate,[147] which is a classic kick indicator. The fact that the Transocean drilling crew—and the BP Company Man—did not appear to catch this kick indicator is in no way a reflection on the job that Joe Keith did that night, especially given the Transocean drilling crew's primary responsibility for monitoring the well.[148] As far as Joe Keith was concerned, he had confirmed that the well was not flowing and nothing he saw after that point would have reasonably lead him to conclude otherwise.

I find it telling that BP's experts cite to results from the OLGA and Transocean simulations for well flow,[149] rather than the surviving Sperry mudlogging data. They do so because, as I described in my Opening Report, there are no clear indications of well flow in the actual Sperry data that Joe Keith was monitoring.

The OLGA model, however, does not accurately illustrate what volume was actually detectable by Joe Keith. As shown in the figure below, which was modified from Figure 18 of BP's Emilsen Report,[150] only

---

[146] *See*, *e.g.*, Appendix C to the Beck Report at 4 and 8; *see also* J. Keith Depo., 3/28/2011 at 180:7-22 ("A. We don't get their -- we don't get their flowout. Q. Could you ask for it? A. We did at one time, but they didn't want us to use it….").

[147] *See*, *e.g.*, M. Sepulvado Depo., 5/11/2011 at 375:15-376:8; R. Sepulvado Depo., 3/10/2011 at 263:11-264:24; and R. Tiano Depo., 8/25/2011 at 263:2-264:4.

[148] *See* Beck Report at 102-107.

[149] *See*, *e.g.*, Grace Report (BP) at 2 and 18; Azar Report (BP) at 2 and 50; and Bourgoyne Report (BP) at 67 (because the pits and Sperry flow-out sensor were bypassed when the kick occurred, Dr. Bourgoyne's reference to a 600 barrel "pit gain" is misleading, as there was at best a 10 barrel pit gain recorded in the pits prior to the sheen test. This would have been the only "pit gain." The rest of mud was diverted overboard and thus undetectable as "pit gain.").

[150] Summary and Conclusions, Deepwater Horizon Incident, prepared by Morton H. Emilsen, 10/17/2011 (BP) (hereinafter "Emilsen Report") at 8.

a small percentage of BP's simulated pit gain would have even reached the rig before flow-out was diverted overboard and out of the mudlogger's monitoring capability. By basing their arguments on simulated data, BP's experts fail to acknowledge that Joe Keith could not see any of this "gain" after 9:10 PM, when the Sperry flow-out sensor and the pits were bypassed. Only the TO drill crew and BP company man were in a position to actually observe the vast majority of flow out of the well since only a negligible amount of the "simulated flow" ostensibly reached the rig prior to diversion overboard.

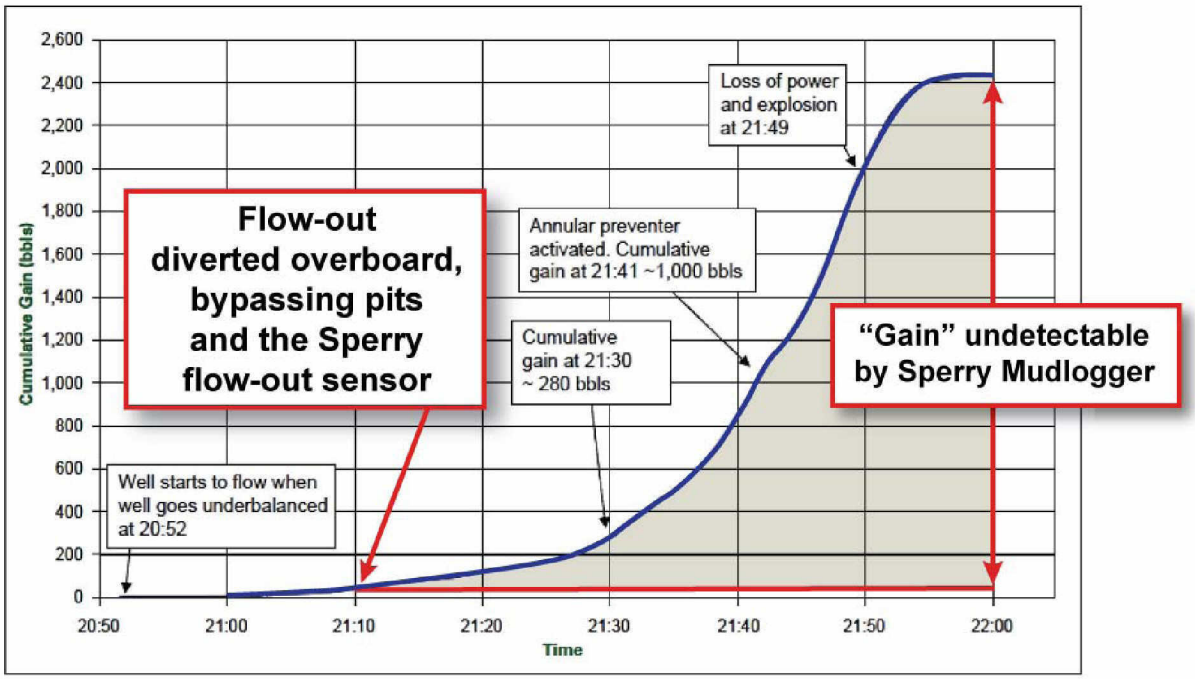

Figure 1: BP's OLGA simulation shows that most of the kick volume was not detectible by the mudlogger.

BP's OLGA simulation also likely overestimates even the small predicted "gain" prior to 9:10 PM. By BP's own admission, OLGA assumed a "fixed net pay" from the reservoir, even though BP acknowledged that "[i]t is possible that initially, only small channels in the cement were open between reservoir and the wellbore."[151] If OLGA used this latter assumption, however, BP concedes that the initial flow would be significantly less than that shown in the figure above.[152] If so, then even

[151] Emilsen Report at 14; *see also* Bly Report, Appendix W, page vii.

[152] Emilsen Report at 14; *see also* Bly Report, Appendix W, page vii.

this corrected "gain" would have been virtually undetectable by the Sperry mudlogger and in line with my analysis based upon the real time pit volume data that indicates at most 10 bbls entered the well before the sheen test.[153]

The simple truth is there were no clear indicators of a kick in the data available to the Sperry mudlogger before BP discharged the lost circulation material spacer overboard. Such indications were likely present in Transocean's Hitec data monitored by the Transocean drilling crew and BP company man, but that data did not survive the sinking of the *Deepwater Horizon*, and had not been made available to Joe Keith.

B. The standpipe pressure increase during the sheen test is at best a subtle indicator of well flow, notable only in hindsight.

As noted in my Opening Report and confirmed by Cameron's expert,[154] the simultaneous and non-standard operations conducted at the behest of BP, Transocean, and M-I SWACO prevented detection of subtle kick indicators—if any were present—before the sheen test. Because the mudlogger was unable to monitor well flow once returns were diverted overboard after the sheen test, the only arguable kick indicator available to Joe Keith that the other parties have cited is the increase in standpipe pressure during the sheen test.[155] This parameter would have been, at best, a subtle indicator of well flow in real-time and is notable only in hindsight.

The 200 psi pressure increase during the sheen test would not have alerted a reasonable mudlogger that a kick was ongoing, especially coming as it did immediately after a visual confirmation that the well was not flowing.[156] Joe Keith, a seasoned mudlogger with 7 years of experience as

---

[153] Beck Report at 114.

[154] Abel Report (Cameron) at 14.

[155] *See*, *e.g.*, Grace Report (BP) at 18 and 20; Bourgoyne Report (BP) at 66; Abel Report (Cameron) at 14-15; Expert Report of L.V. McGuire, 10/17/2011 (Cameron) at 6; Barnhill Report (Transocean) at 6, 34-35; BP-Macondo Report for the United States of America, prepared by Richard Heenan, P.Eng., 8/31/2011 (hereinafter "Heenan Report") at 21.

[156] *See* Beck Report at 113-114.

a mudlogger on the *Deepwater Horizon* and 18 years in the Gulf of Mexico, testified it was not abnormal for the Transocean drilling crew to leave trapped pressure on the standpipe, and that he would expect a slight pressure rise after the pumps were shut off.[157] When using an excessive amount of heavy spacer, a reasonable mudlogger could expect such typical pressure responses to be magnified.

Further, mudloggers are not trained to associate increases in standpipe pressure with a kick. As described in my Opening Expert Report, a standard kick indicator mudloggers are likely taught to expect is a decrease in standpipe or pump pressure—not an increase.[158]

On Joe Keith's 5,000 psi pressure scale,[159] a 200 psi increase would be difficult to detect. Even if he had detected the increase, because the pressure appeared to behave normally once the displacement resumed at 9:14 PM, a reasonable mudlogger may have discounted the minor pressure anomaly during the sheen test. By the time more significant pressure anomalies were present around 9:30 PM, the Transocean drilling crew had already detected problems with the well and halted the displacement.[160] At this point, the Transocean Drilling crew had sole responsibility for responding to the kick—the mudlogger does not participate in well control operations, he merely assists with monitoring.[161]

As thoroughly discussed in my Opening Report, and supported by several of the other parties' experts,[162] the driller has primary well monitoring responsibility, and the mudlogger is just a "second set of eyes" on the well. A drilling crew traditionally has more training than a

---

[157] J. Keith Depo., 3/28/2011 at 103:16-25 (" . . . 90 percent of the time, when they [Transocean drill crew] do shut the pumps off they do not bleed the stand pipe pressure off, and sometimes the pressure will come up a little bit and then level out.").

[158] *See*, *e.g.*, *also* HAL0051030, Surface Data Logging Core Fundamentals at HAL0051189.

[159] *See* J. Gisclair Depo., 3/14/2011 at 69:1-12.

[160] Beck Report at 114.

[161] *See*, *e.g.*, Transocean Well Control Handbook, Section 1, Subsection 5.15, Exhibit 590 at TRN-MDL-00286786.

[162] *See*, *e.g.*, Beck Report at 103-107; *see also* Azar Report (BP) at 11; and Grace Report (BP) at 8.

mudlogger, has higher certification requirements, and is able to access data not available to the mudlogger, such as knowledge of ongoing rig activities. Also, should an anomaly arise in the mudlogging data, the drilling crew, not the mudlogger, is able to take action to diagnose and correct any problems.

C. Joe Keith properly monitored all data available to him and would not have been expected to stop the displacement.

BP's expert Dr. Azar appears to suggest that if the mudlogger was not aware of all well parameters at all times, he should have stopped the displacement.[163] While I do not disagree with the general assertion that the mudlogger is required to continuously monitor the well, I do disagree with any implication that the mudlogger is obligated to monitor data that is not available to him. BP, Transocean, and M-I SWACO knowingly designed and executed a displacement that blinded the mudlogger to some of his traditional kick indicators[164] and knew that pit total, gas concentration, and Sperry flow-out data would not be available when they discharged the spacer overboard. As a backup to the driller,[165] the mudlogger was not expected to stop all operations simply because he would be unable to monitor each and every possible drilling-related parameter. BP's Macondo well site leader has confirmed this.[166] Indeed, because BP and M-I SWACO appeared determined to discharge the lost circulation material spacer overboard, it is doubtful that any concern raised by the mudlogger would have resulted in any change to the overboard discharge procedures.

Dr. Azar, BP's expert, suggests that simultaneous operations are a normal part of drilling. I do not disagree. However, when contemplating

---

[163] Azar Report (BP) at 11 and 44.

[164] *See, e.g.*, M. Sepulvado Depo., 5/11/2011 at 374:24-376:20 ("[W]henever that dump valve is open, it isolates their flowmeter."); R. Sepulvado Depo., 3/10/2011 at 32:25-34:10 and 533:22-534:8 ("The flow shows will change, the crane operations make them change, swing the crane with a load over the side, you may get a 30-barrel increase in volume pretty quick. . . And that's the same thing you see when you get a kick out of the well, in the well.").

[165] Beck Report at 103-107.

[166] BP's Macondo well site leader, Ronnie Sepulvado, would not expect the mudlogger to inform him if the Sperry flow-out sensor was bypassed. *See* R. Sepulvado Depo., 3/10/2011 at 126:3-127:6.

simultaneous operations, the operator must ensure that any adverse impact on rig safety is mitigated, or else must delay the proposed operation until it can be conducted safely. This is specified in BP's own written practices, which require that "[a] risk assessment of simultaneous operations and threats shall be performed on each facility or field in order to identify the risks across the complete range of well activities."[167] I have seen no evidence such an assessment was conducted prior to the final Macondo displacement.[168]

Further, the suggestion by some of BP's experts that "BP reasonably relied on Sperry Sun to monitor pit levels and flow rates to determine if an influx of formation fluids had occurred"[169] is misleading, since BP assisted in drafting, and approved, the displacement procedures that made pit level and flow rate monitoring difficult before 9:10 PM and impossible after that time.[170] In my opinion, this is yet another attempt by BP to shift the blame for its own poor decisions to one of its contractors.

Nevertheless, Joe Keith monitored all data available to him, as evidenced by the four anomalies he communicated during the final displacement.[171] The available data exhibited none of the traditional kick indicators. Joe Keith had no way of knowing the well was kicking until after

[167] Depo. Ex. 1575 (BP's ETP GP 10-75—Simultaneous Operations) at BP-HZN-2197MDL00408287; *see also* Depo. Ex. 6121 at BPHZN-BLY00034593 (BP's Drilling and Well Operations Practice) ("Major Accident Hazards as a result of Simultaneous Operations shall be identified so that controls and mitigations can be put in place before the activity takes place."); and Depo. Ex. 590 at TRN-MDL-00286819. (Transocean's Well Control Handbook) (noting individuals involved in rig activity should "[k]eep all mud treatment and pit transfers to the absolute minimum during critical sections of the well.").

[168] *See* J. Bellow Depo., 05/03/11 at 627:4-16 and 634:22-635:19.

[169] Grace Report (BP) at 9.

[170] *See*, *e.g.*, B. Billon Depo., 6/24/2011 at 365:21-367:11; J. Keith Depo., 3/28/2011 at 85:7-88:7 and 136:3-7; L. Lindner Depo., 9/14-15/2011 at 125:23-130:7, 231:10-17, 232:25-233:7, 243:9-244:21 and 449:5-14; R. Sepulvado Depo., 3/10/2011 at 47:6-48:1.

[171] *See* Beck Report at 110.

the Transocean drilling crew had already recognized an anomaly and stopped the pumps around 9:30 PM.[172]

BP's experts conclude that the primary reason for the loss of well control was that the kick was not detected in time by the Transocean drilling crew and the Sperry mudlogger.[173] I partially agree—the kick was not detected in time by Transocean and BP with the data available to them. The Sperry mudlogger had no data clearly indicative of a kick. Moreover, to the extent that proper steps were not taken to shut in the well after 9:30 PM and a blowout ensued, that responsibility falls squarely on Transocean's shoulders because they were aware of the pressure anomaly and had the ability and the responsibility to activate the blowout preventer. Joe Keith had neither.

D. Joe Keith could not have reasonably set flow, pit, or pressure alarms that would have indicated a kick.

Some experts have implied that Joe Keith should have set alarms in his InSite monitoring software that would have alerted him to any slight change in well status.[174] Joe Keith did have alarms set to monitor the displacement;[175] there is no indication, however, that any of the alarms alerted Mr. Keith to the fact that the well was flowing. It is not always possible to set alarms for potential kick indicators. For example, when pumping into the well from an unmonitored sea chest, pit volume will constantly increase. An alarm set to detect a slight pit gain would continuously sound because the pits are continuously gaining mud. Similarly, during the final displacement, the rate of flow-out peaked at over 1200 gallons per minute.[176] If Joe Keith had set an alarm to monitor for

[172] Some have suggested that an 8-10 minute restroom, coffee, and cigarette break that Joe Keith took some time between 8:30 PM and 9:00 PM was improper. *See*, *e.g.*, Abel Report (Cameron) at 44. I completely disagree. When working a 12 hour shift, it is entirely reasonably to take a restroom break provided proper safeguards are taken. Mr. Abel's implication otherwise is disingenuous. On April 20, Joe Keith took such proper safeguards by alerting the assistant driller he was taking a break. J. Keith Depo., 3/28/2011 at 151:17-152:17 and 236:16-22.

[173] *See*, *e.g.*, Azar Report (BP) at 1 and 50; and Bourgoyne Report (BP) at 66-67.

[174] *See*, *e.g.*, Azar Report (BP) at 12 and Bourgoyne Report (BP) at 65.

[175] J. Keith Depo., 3/28/2011 at 331:19-24.

[176] Depo. Ex. 620.

excessive flow during the displacement, he would have set it higher than 1200 gallons per minute, and the increase in flow at 9:08 PM,[177] which some have cited as a kick indicator, would not have triggered his alarm, as this flow was less than 1200 gallons per minute. It would not have been practical nor common practice to reset a flow-out alarm every time the Transocean drilling crew changed pump speed during the displacement. The same thing is true of standpipe pressure. During the final displacement, standpipe pressure exhibited frequent and significant expected fluctuations; it would have been impractical under the circumstances for Joe Keith to set alarms which would be meaningless only minutes later.

Moreover, without a pressure/volume schedule, as described in my Opening Report,[178] the mudlogger would not necessarily have known what values to use when setting his alarms during a complex displacement.

E. Sperry had no say in how the rig was plumbed or how the displacement was to be run.

As described in my Opening Report, I agree that a closed-pit system is the preferred method of operating a displacement, and that the displacement could have been conducted in a manner which utilized a closed pit system.[179] Cameron's expert alleges that both Transocean and Sperry failed to "maintain a material balance"[180]—meaning a closed pit system as described in Appendix C to my Opening Report. However, the manner in which the rig is plumbed during a displacement was not Sperry's

[177] Note, it is not clear whether the increase in flow-out was due to a flowing well, was a result of the trip tank dump which began around 9:59 PM, or was caused by rig movement and crane operations. *See*, *e.g.*, Beck Report at 110-112.

[178] *See* Beck Report at 113. *See also* M. Sepulvado Depo., 5/11/2011 at 209:8-25 and 213:1-6.

[179] Note, there were alternate routings available that would have at least allowed the Sperry flow meter to remain online while displacing overboard. *See*, *e.g.*, Depo. Ex. 5125; and Heenan Report (US) at 18.

[180] Abel Report (Cameron) at 14.

decision.[181] BP, Transocean, and M-I SWACO made the decisions to pump from the unmonitored sea chest, to divert overboard, and to move additional fluid into and out of the designated active pits.[182] Sperry had no involvement in these decisions which complicated well monitoring. Joe Keith, the Sperry mudlogger, simply monitored the situation he was presented with using the sensors made available to him.

F. BP's expert makes claims not supported by the surviving mudlogging data.

In his opening report, BP's expert Robert Grace identified three anomalies that I do not see in the Sperry data.

Mr. Grace stated: "[a]t 8:52 PM, the mud pumps were slowed and the drill string pressure remained constant. At this time the well was flowing."[183] This seems to imply the pressure response was caused by a flowing well, when in fact the reduction in pump rate was on the booster pump, which is not connected to the standpipe and thus has no effect on the standpipe pressure. In truth, when the pumps slowed around 8:52 PM, the pressure in the well also decreased as expected, it did not remain constant. This is shown in the data below.

---

[181] *See*, *e.g.*, B. Billon Depo., 6/24/2011 at 365:21-367:11; J. Keith Depo., 3/28/2011 at 85:7-88:7 and 136:3-7; L. Lindner Depo., 9/14-15/2011 at 44:25-45:11, 149:24-150:4, 469:12-22, 472:15-21, and 479:21-480:6; R. Sepulvado Depo., 3/10/2011 at 47:6-48:1; Tr. of USCG/MMS Investigation (J. Guide testimony), 7/22/2010 at 161:24-162:4.

[182] *See*, *e.g.*, Tr. of USCG/MMS Investigation (J. Guide testimony), 7/22/2010 at 161:24-162:4 ("Q. But it is Transocean that operates this rig and BP that makes the decision as to whether or not certain operations are going to be performed and when they are performed, is that correct? A. That is correct."); B. Billon Depo., 6/24/2011 at 365:21-367:11; J. Keith Depo., 3/28/2011 at 85:7-88:7 and 136:3-7; L. Lindner Depo., 9/14-15/2011 at 125:23-130:7, 231:10-17, 232:25-233:7, 243:9-244:21 and 449:5-14; R. Sepulvado Depo., 3/10/2011 at 47:6-48:1.

[183] Grace Report (BP) at 18.

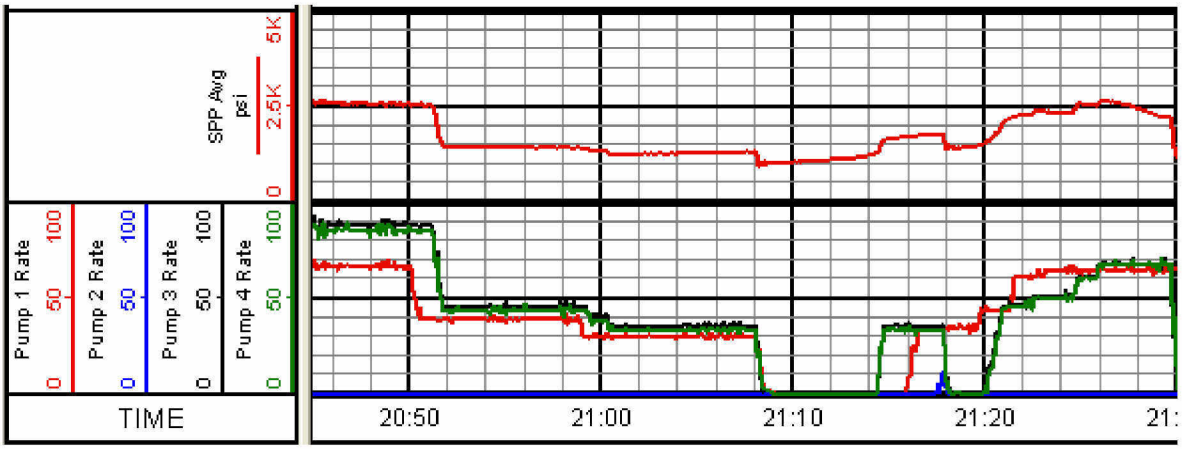

Figure 2: Sperry mudlogging data interpreted incorrectly by BP's expert Mr. Grace.

Mr. Grace also stated: "[a]t roughly 8:59 PM, the pumps were further slowed and the pressure on the drill string began to increase. The well had to have been flowing during this time." [184] Again Mr. Grace's analysis is not consistent with the mudlogging data. When the pumps were slowed at 8:59 PM, the pressure decreased as would be expected. A close analysis of the surviving data reveals a pressure increase beginning at 9:00 PM, but this pressure increase is not something a reasonable mudlogger would have detected in real time, especially given the presence of several simultaneous fluid transfers, including dumping the sand traps, emptying the trip tanks, and switching well returns from pits 9 and 10 to pit 7 and then pit 6, as discussed in my Opening Report.[185]

Finally, Mr. Grace identified what he believes is an "inconsistency," describing that after the sheen test, "during the periods of constant pump rates, the drill string pressure increased until about 9:26 PM, and then it began to decrease."[186] I am unsure what "periods of constant pump rates" he is referring to. During this timeframe, the drillers were staggering the pumps and ramping them up gradually, as can be seen in the data above. According to Joe Keith, this was abnormal behavior, and Mr. Keith called to investigate.[187] Between 9:14 PM and 9:26 PM, there are no periods where

[184] Grace Report (BP) at 18.

[185] *See, e.g.*, Appendix C to the Beck Report at 35-39.

[186] Grace Report (BP) at 19.

[187] *See* Beck Report at 110.

the pump rates are sufficiently steady to draw any conclusions about a well flowing from the pressure response.[188] Rather, the observed pressure response is as one would expect: as total pump rate increases, pressure generally increases. Once pumps level off, pressure in the well begins to decrease as heavy spacer is displaced by lighter seawater.

X. Summary.

My opinions and conclusions, as set forth in my Opening Report, remain unchanged. In my opinion, BP's reckless failure to maintain control of the well, and to a lesser extent Transocean's conduct, caused the blowout. Halliburton and Sperry did not in any way cause, and are not responsible for, the blowout or any consequences thereof.

[188] *C.f.* Heenan Report (US) at 23 (Noting that pressure "[a]nalysis (particularly in real-time for the rig personnel) is difficult from 21:15 to 21:30 due to changes in pump rate.").

I reserve the right to modify this report and to supplement my opinions if additional data becomes available and in response to reports served by other parties.

Dated: November 7, 2011

Frederick Eugene Beck

MDL NO. 2179

In re: Oil Spill by the Oil Rig "Deepwater Horizon" in the Gulf of Mexico, on April 20, 2010

DR. FREDERICK E. BECK REBUTTAL SOURCE / RELIANCE APPENDIX

BATES RANGE	DEPO / TRIAL EX#	DATE	SUMMARY / DESCRIPTION
	1	9/8/2010	Deepwater Horizon Accident Investigation Report - dated September 8, 2010 ("Bly" Report)
	2	9/8/2010	Appendices to Deepwater Horizon Accident Investigation Report - dated September 8, 2010
CON67	**126**	4/14/2010	Hafle email to Miller re Macondo APB
BP-HZN-2179MDL00269659-269673	**184**	4/16/2008	BP Group Practice GP 10-60 Zonal Isolation Requirements during Drilling Operations and Well Abandonment and Suspension
TRN-MDL-00286767-287162	**590**	3/31/2009	Transocean Well Control Handbook
HAL_0048974	**604**		BP - OCS-G32306 001 ST00BP01, Mississippi Canyon Blk. 252, Macondo Bypass, Deepwater Horizon
HAL_0266303	**607**		Deepwater Horizon - Flow Diagram (Return flow to pits)
HAL_0048974	**620**		(Graph) *oversized*
BP-HZN-MBI00128708-128756	**738**	4/19/2010	E-Mail - From: Jesse Gagliano Sent: Mon Apr 19 01:58:10 2010 - Subject: Updated Info for Prod Casing job
BP-HZN-2179MDL00015195	**967**		BP / Deepwater Horizon - Rheliant Displacement Procedure - "Macondo" OCS-G32306
BP-HZN-2179MDL03082878-3083151	**986**		Chief Counsel's Report_2011: National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling
BP-HZN-MBI00126338-126339	**1241**	4/13/2010	Email from R. Bodel to M. Beirne re Macondo TD
HAL_0010699-10720	**1388**	4/15/2010	BP 9 7/8" x 7" Production Casing Design Report for Brian Morel
BP-HZN-2179MDL00033079-33082	**1517**	4/16/2010	Cocales email to Morel re Macondo STK geodetic
BP-HZN-2179MDL00408286-408287	**1575**	4/16/2008	BP GP 10-75 Simultaneous Operations
	2033	6/11/2010	Telephone Interview of: Jesse Marc Gagliano - Friday, June 11, 2010
BP-HZN-MBI00129068-129069	**2584**	4/20/2010	E-Mail - From: Morel, Brian P Sent: Tue Apr 20 14:31:49 2010 - Subject: RE: Circulation
BP-HZN-MBI00143259-143261	**2659**	4/14/2010	Drilling & Completions MOC Initiate
BP-HZN-MBI00192549-192551	**2830**	11/18/2009	Three-page well plan Authorization for Expenditure signed 11/18/09
BP-HZN-2179MDL01591521-1591535	**3005**	8/19/2010	BP - Static Kill and Cement Review and Summary
BP-HZN-BLY00061514-61517	**3188**	4/28/2010	Bob Kaluza Interview

BATES RANGE	DEPO / TRIAL EX#	DATE	SUMMARY / DESCRIPTION
TRN-INV-01747442-1747659	**3808**	6/20/2011	Macondo Well Incident Transocean Investigation Report, Volume 1
BP-HZN-SNR00000122-150	**4021**		Application for Permit to Drill a New Well
BP-HZN-2179MDL00247793	**4091**	4/2/2010	E-mail from Mark Hafle to Brian Morel, Subject: Macondo 9-78 LOT FIT Worksheet.xls, marked as Confidential
BP-HZN-MBI 00125958	**4242**	4/12/2010	April 11 and 12, 2010 E-mail string from David Sims to Brian Morel, from Brian Morel to David Sims Subject: Macondo times, marked as Confidential
	4842		Presentation re: designing a cement job
TRN-INV-02514877-2514881	**5125**	9/30/2010	E-mail string among Bob Walsh and Wesley Bell, et al.
BP-HZN-BLY00034504-34604	**6121**		BP Drilling and Well Operations Practice E&P Defined Operating practice GP 10-00
BP-HZN-2179MDL00339799-339820	**6291**	3/31/2009	BP SPU GoM Drilling and Completions D&C Recommended Practice for Management of Change, March 31, 2009, marked as CONFIDENTIAL
BP-HZN-2179MDL00022159-22208	**6320**		Contract for Gulf of Mexico
BP-HZN-2179MDL00032979-32981	**6321**	4/6/2010	E-mail from Mr. Daly to Mr. Inglis
	60071	8/31/2011	Expert Report of Glen Benge (USA)
	60079	6/11/2010	Transcript of Jesse Gagliano before US House of Representatives
	60080	10/17/2011	Expert Report of Sam Lewis (Halliburton)
	60081	10/17/2011	Expert Report of Frederick E. Beck on Well Design, Control, Drilling, and Monitoring (Halliburton)
	60082	10/17/2011	Expert Report of John P. Hughett, P.E. (Halliburton)
BP-HZN-2179MDL00003541-3545	**60095**	4/16/2010	BP Daily Operations Report - Partners (Completion)
	60110	8/31/2011	Expert Report of Richard Heenan (USA)
	60118	10/7/2010	Transcript of Testimony of Joint USCG/BOEM Investigation
	60120	8/24/2010	Transcript of Testimony of Joint USCG/BOEM Investigation
	60121	12/7/2010	Transcript of Testimony of Joint USCG/BOEM Investigation
	60124	9/23/2011	Expert Report of Calvin Barnhill (TO)
HAL_0506948-507095	**60504**	11/8/2010	The National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling Hearing Transcript
	60521		Code of Federal Regulations Title 30 Part 250 Oil and Gas and Sulphur Operations in the Outer Continental Shelf, Subpart D ("30 CFR § 250")
	60659	8/26/2011	Expert Report of Bea-Gale (Pls), 08-26-11
	60660	8/26/2011	Expert Report of David Pritchard (Pls), 08-26-11
	60662	8/26/2011	Expert Report of Dr. Alan Huffman Submitted on Behalf of the United States Department of Justice
	60811	7/22/2010	Testimony of Joint USCG_BOEM Investigation
	60815	8/27/2010	2010 08 27 Testimony of Joint USCG_BOEM Investigation

BATES RANGE	DEPO / TRIAL EX#	DATE	SUMMARY / DESCRIPTION
BP-HZN-BLY00061224-61227		5/11/2010	Handwritten Notes
BP-HZN-CEC021441-21452		4/18/2010	Halliburton 9 7/8" x 7" Production Casing
BP-HZN-CEC021665-21667		4/14/2010	BP Drilling & Completions MOC Initiate
BP-HZN-CEC022666-22668		4/17/2010	Email from B. Cocales to G. Walz, et al. re Cement Procedure
BP-HZN-MBI00192552		1/27/2010	BP Supplemental Authorization for Expenditure
BP-HZN-MBI00192559		4/14/2010	BP Authorization for Expenditure
BP-HZN-MBI00413304			Macondo Production Casing
HAL_0010592-10611		4/15/2010	BP 9 7/8" x 7" Production Casing Design Report for Brian Morel
HAL_0051030-51276		01/00/2001	Surface Data Logging Core Fundamentals
TRN-INV-01824082		9/16/2010	Email from TSC Conrols to P. Roller re Flow Line Sensor
		5/11/2010	Transcript of Senate Energy and Natural Resources Committee
		3/8/2010	Insite Data
		4/16/2010	Insite Data
		10/25/2011	Expert Report Prepared for M-I LLC by George H. Medley, Jr., P.E.
		10/17/2011	Expert Report of Gordon Cain (MOEX)
		10/17/2011	Expert Drilling Report of Roger Vernon (Anadarko)
		10/17/2011	Evaluation of the Cementing on the 9 7/8" x 7" Production Casing String on the Macondo Well," Expert Report by Fred Sabins
		3/10/2011	Sepulvado, Ronald W. Deposition Transcript
		10/17/2011	Report of Morris Burch (BP)
		10/17/2011	Expert Report of Kathleen M. Sutcliffe, Ph.D
		10/17/2011	Expert Report of Chuck Schoennagel L.L.C., MMS Regulatory Regime
		10/17/2011	Expert Report on Behalf of BP, Robert D. Grace, P.E.
		10/17/2011	Expert Report of David G. Calvert (Weatherford)
		10/17/2011	Expert Report of J.J. Azar, Ph.D. (BP)
		10/17/2011	Expert Report of Adam T. Bourgoyne (BP)
		10/17/2011	Expert Report of Gregory M. McCormack (Weatherford)
		10/17/2011	Expert Report of L. William Abel (Cameron)
		10/17/2011	Expert Report of Donald J. Weintritt, P.E. LA and TX (Retired)
		10/17/2011	Review of the Macondo #1 9-7/8" x 7" Production Casing Cementation Operation, by Ian A. Frigaard (Cameron)
		10/17/2011	Expert Report of Kevin Trahan (Cameron)
		10/17/2011	Expert Report of Brent J. Lirette on Behalf of Weatherford U.S., L.P.
		10/7/2011	Expert Report of Marion M. Woolie (Weatherford)
		4/21/2011	Walz, Gregory Stephen Deposition Transcript

BATES RANGE	DEPO / TRIAL EX#	DATE	SUMMARY / DESCRIPTION
		4/22/2011	Walz, Gregory Stephen Deposition Transcript
		10/17/2011	Review of the Production Casing Design for the Macondo Well, Expert Report by David Lewis
		3/17/2011	Chaisson, Nathaniel Deposition Transcript
		5/11/2011	Sepulvado, Murry Deposition Transcript
		8/25/2011	Tiano, Robert Deposition Transcript
		3/28/2011	Keith, Joseph Deposition Transcript
		10/17/2011	Summary and Conclusions, Deepwater Horizon Incident, prepared by Morton H. Emilsen (BP)
		10/17/2011	Expert Report of L.V. McGuire (Cameron)
		3/14/2011	Gisclair, John Deposition Transcript
		6/24/2011	Billon, Brad Deposition Transcript
		9/14/2011	Lindner, Leo Thomas Deposition Transcript
		9/15/2011	Lindner, Leo Thomas Deposition Transcript
		6/2/2011	Lacy, Kevin D. Deposition Transcript
		5/9/2011	Guide, John Deposition Transcript
		7/15/2011	O'Bryan, Patrick Deposition Transcript
		5/16/2011	Breazeale, Martin Deposition Transcript
		2/10/2011	Corser, Ken Deposition Transcript
		10/11/2011	Douglas, Scherie Deposition Transcript
		4/26/2011	Cocales, Brett Deposition Transcript
		10/17/2011	Expert Report of David Bolado
		4/15/2011	Gray, Kelly Deposition Transcript
		7/29/2011	Clark, Skip Deposition Transcript
		5/3/2011	Bellow, Jonathan Deposition Transcript
			Beck Rebuttal Figure 1: BP's OLGA's simulation shows that most of the kick volume was not detectible by the mudlogger
			Beck Rebuttal Figure 2: Sperry mudlogging data interpreted incorrectly by BP's expert Mr. Grace.