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 Applies to: ALL CASES and 2:10-cv-02771	MDL No. 2179 Section: J The Honorable Judge Barbier Mag. Judge Shushan

AMENDED REBUTTAL EXPERT REPORT OF GLEN STEVICK, Ph.D., P.E. ON DESIGN AND MAINTENANCE OF THE BLOWOUT PREVENTER

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INTRODUCTION

This report is offered in rebuttal to reports offered on behalf of other parties to this litigation, as described in further detail below. My opinions are based upon: the materials and information I have reviewed, including materials related to the Phase I and Phase II forensic testing and examination of the Deepwater Horizon ("DWH") blowout preventer ("BOP") and testimony, reports, and other documents related to DWH BOP, including the materials identified in Appendix A; my analysis of that information; my education, training, experience and knowledge in the areas of mechanical engineering, failure analysis and design, and material behavior; and my knowledge of oilfield and offshore equipment (e.g. offshore platforms, BOPs, casings, and drill strings). In forming my opinions I have not been asked to nor have I made any assumptions, nor have I presumed any facts beyond those that are cited as material relied upon in this Report and its attachments. This report is written with the expectation that the reader will have some familiarity with the Macondo incident and the reports addressed below.

I. Executive Summary

I have found the following to be true:

1. The DWH BOP was not suitable for the Macondo well for many reasons, including because: the wrong blind shear ram ("BSR") was used; only one BSR (instead of two) was used; the wrong control system was used; tandem boosters were not used; and the wrong operational sequence was used.

2. The Macondo drill pipe was off-center when the BSR closed and off-center drill pipe was well known and foreseeable.

3. The automatic mode function ("AMF")/Deadman failed to activate the BSR at the time of the incident because Transocean's flawed condition-based maintenance program allowed the blue control pod batteries to lose their charge and the yellow control pod solenoid 103Y to be incorrectly wired but did not identify either problem.

4. British Petroleum ("BP") was actively involved in the design of the DWH BOP and did not rely exclusively on Transocean Offshore Deepwater Drilling, Inc. ("Transocean") and Cameron International Corp. ("Cameron") for the BOP.

Since drafting my Opening Report, I have studied the numerous other expert reports in this case relating to the design, operation and maintenance of the DWH BOP.[1] Several of those experts reinforced my original options. Several of those experts, however, have reached different conclusions than mine. For the reasons described further below, I find none of those contrary opinions persuasive.

II. Properly Operated BOP using BAST could have Stopped the Macondo Blowout

Some experts contend that the DWH BOP was suitable for the Macondo well.[2] I disagree, because the best available and safest technology ("BAST") was not implemented in the DWH BOP. Better and safer technology was available to BP and Transocean, which could have and should have implemented in the DWH BOP. A proper BOP design and operation based on BAST should have included a casing shear ram

[1] O'Donnell, D.L., Expert Report submitted by Cameron International Corp., October 17, 2011 ("O'Donnell Report"); McGuire, L.V., Expert Report submitted by Cameron International Corp., October 17, 2011 ("McGuire Report"); Childs, E.G., Expert Report submitted by Transocean, September 23, 2011 ("Childs Report"); Shanks, F.E., Expert Report submitted on behalf of BP, October 17, 2011 ("Shanks Report"); Davis, R.R., Robinson, J.N., Novak, P.R., Merala, R., Report on the Deepwater Horizon Blowout Preventer Examination and Testing on behalf of the Department of Justice, August 31, 2011 ("Davis Report"); Perkin, G.S., Report on behalf of the Plaintiffs' Steering Committee, August 26, 2011 ("Perkin Report"); Shanks, F.E., Report on BOP Design submitted on behalf of BP, October 17, 2011 ("Shanks Report"); KnightHawk Engineering, Report on the Deepwater Horizon Incident on behalf of Cameron, October 17, 2011 ("KnightHawk Report"); Able, L. W., Macondo Incident Report submitted by Cameron, October 17, 2011 ("Able Report"); Dias, P., Expert Report Regarding Blowout Preventer Maintenance Methodology submitted by BP, October 17, 2011 ("Dias Report"); and Zatarain, A., Expert Report Regarding Transocean Deepwater Horizon Blowout Preventer Subsea Control System submitted by BP, October 17, 2011 ("Zatarain Report").

[2] Childs Report p. 25; Shanks Report, p. 50.

("CSR") and two BSRs, one above and one below the CSR. The BSRs should have both been equipped with tandem boosters and a higher booster pressure (5,000 psi) to provide an acceptable margin of safety. The proper actuation sequence should be as follows:

1. actuation of the CSR and lifting of the "tail" or drill string.
2. actuation of the BSR below the CSR to seal the well.
3. actuation of the BSR above the CSR providing a sure seal.

Closing the CSR first ensures the pipe is cut and centered and reduces flow in a blowout situation. Closing the first BSR below the CSR will likely seal the well. However, if any seals are damaged due to erosion, the flow will be further reduced and the second BSR will easily seal the well. Erosion is proportional to the flow velocity squared, thus, the progressive drop in fluid flow will virtually eliminate any damage potential to the second BSR closure.

Further, a lower annular should have been shut first to control flow up the riser. The upper annular should not be closed unless the variable bore rams are already closed. This provides a backup in case the drill pipe erodes through at the lower annular. This would allow the drill pipe to be hard sealed and the well contained.

II. The BOP was not Suitable for the "Well from Hell"

A Transocean expert concluded that the DWH BOP was suitable for Macondo,[3] and a BP expert concluded that the DWH BOP was suitable for Macondo except for the BSR.[4] I disagree with both. As discussed below, the BSR was unsuitable for Macondo and there were numerous other flaws with the DWH BOP that made it unsuitable for Macondo.

The Macondo well was drilled to a depth of approximately 18,360 ft, including 12,360 ft below the seafloor. When drilling in deep waters, there are additional factors that increase the difficulty of drilling as well as the requirements for a BOP. The well, riser, and drill pipe pressures are higher due to the greater depths, and the drill pipe needs to be longer and thus

[3] Childs Report, p. 25.

[4] Shanks Report, p. 50.

more prone to off-center positioning and bowing from axial loads. The increased difficulties of deepwater drilling are well known in the industry.[5]

The Macondo well was a *"challenging well to drill."*[6] One BP technical employee went so far as to call Macondo *"one of those wells from hell"* due to problems during drilling.[7] That BP employee further testified that *"in terms of a technical criticality, Macondo would fall under . . . the new classification of what a critical well would look like."*[8]

Despite the challenging nature of the Macondo well, the failure of BP and Transocean to implement a BOP using BAST resulted in the DWH relying on a BOP that was not able to shear drill pipe and seal the well under foreseeable operating conditions. Contrary to positions offered on behalf of BP[9] and Transocean[10], the DWH BOP was not suitable for the Macondo well.

A. The Macondo BSR Lacked a Sufficiently High Safety Factor

A safety factor or design margin is the actual failure load divided by the operating load. Actual failure load, as the name indicates, is the load level or pressure at which a component is expected to or will actually fail. For example, if one is designing a pipe to transport high pressure gas at 1,000 psi, the actual failure or burst pressure should be 4,000 psi. This would correspond to a safety factor of 4. Note, for shearing pipe, the shear force

[5] See, e.g., Drake, L.P., Well Completion Design, Elsevier Science, 2009; French, L.S., Richardson, G.E., Kazanis, E.G., Montgomery, T.M., Bohannon, C.M., and Gravois, M.P., Deepwater Gulf of Mexico 2006: America's Expanding Frontier, OCS Report MMS 2006-022, May 2006, available at http://www.gomr.boemre.gov/homepg/whatsnew/techann/2006/2006-022.pdf.

[6] Deposition of Billy Ambrose, July 18-19, 34:7-14

[7] Deposition of Erick Cunningham, March 23-24, 2011, 232:7-19; Exhibit 628.

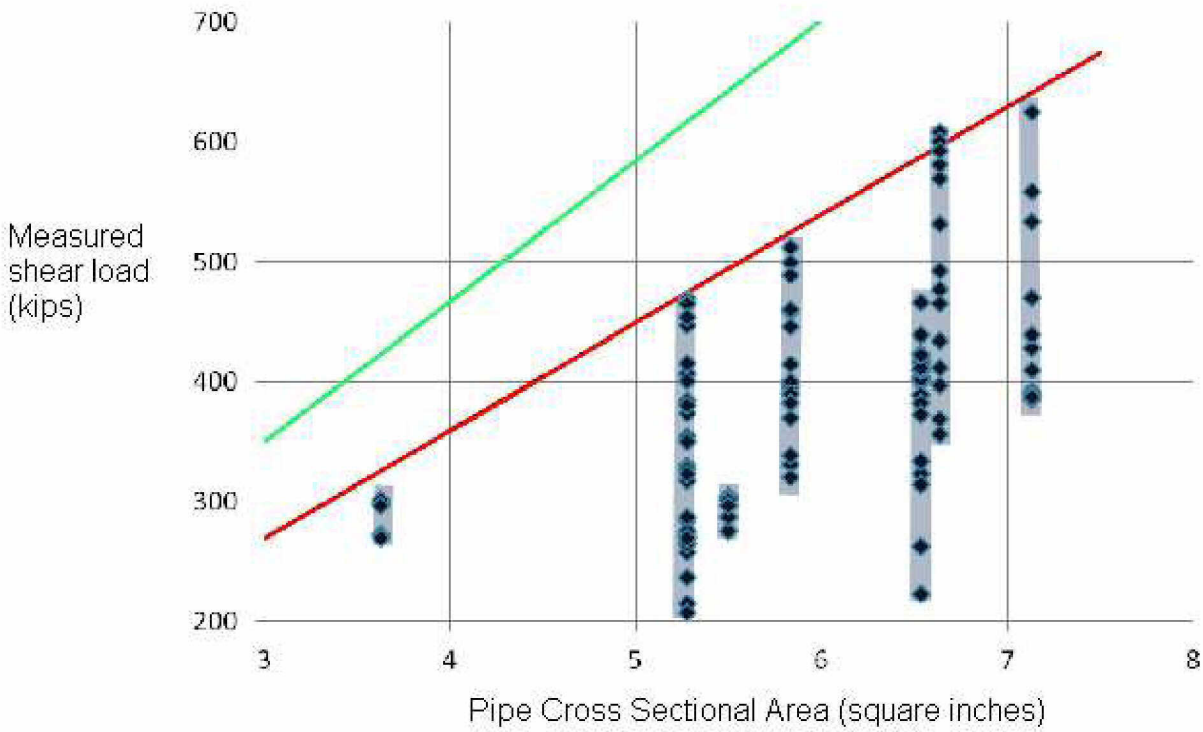
[8] Deposition of Erick Cunningham, March 23-24, 2011, 198:12-17.

[9] Shanks Report, p. 50.

[10] Childs Report, p. 25 (stating the "Deepwater Horizon BOP stack was suitable for use").

capacity of the BSR should be higher than the shear force necessary to shear pipe in all possible operating conditions by an acceptable safety margin. Fortunately, the force required to shear pipe has a well defined upper limit, thus a safety factor in the 1.3 to 2.0 range should be adequate. Unfortunately, this safety factor was not present in the BSR design for the DWH BOP.

Transocean has pointed to maximum allowable surface pressure ("MASP") and shearing calculations to show that the BSR used in the DWH BOP was capable of shearing the 5.5 inch and 6.25 inch drill pipe used at Macondo.[11] But these calculations only establish that the BSR was capable of shearing the 5.5 inch and 6.25 inch drill pipe under ideal circumstances, including sharp blades and centered drill pipe. Shear data from West Engineering shows that necessary shear loads can vary by a factor of 2 or more for the same size pipe as shown in Fig 1 below:[12]



[11] Childs Report, p. 24-27.

[12] West Engineering Services, *Shear Ram Capabilities Study for U.S. Minerals Management Service,* Requisition No. 3-4025-1001, September 2004 (data for S135 pipes).

Fig. 1. Test data measured shear force as a function of pipe cross sectional area. The data within each vertical grey bar corresponds to a single pipe size and weight. The red and green lines are a plot of equation 1 from Appendix D of the author's main report for a safety factor of 1.0 and 1.3, respectively.

This variation in necessary shear loads shown in the West Engineering data would also be true of Cameron's data and Transocean's test data. In fact, the Cameron capacity chart can be reconstructed using the equation describing the red line in Fig 1 above.[13] The red line in Fig. 1 provides a good fit to the upper bound of the test data, but provides no additional margin for unexpected conditions.

In my opinion, the DWH BSR should have been designed with a minimum safety factor of 1.3. A safety factor of 1.3 is represented by the green line in Fig. 1. Such a safety factor provides a clear design margin to account for dull blades, friction, higher than expected well pressure and high end material properties. A minimum safety factor of 1.3 relative to the upper bound is not an excessive design burden. As described in Appendix B of the author's opening report, this could easily be met with the technology available at the time the DWH was designed.[14] Almost everything around us from the chairs we sit in to the pressure vessels and piping on the DWH, have a safety factor greater than 2 (e.g., the code for escalators in one state called for a safety factor of 14).[15] For piping and pressure vessels it's actually in the 3-4 range.[16] This is significantly higher than the safety factor

[13] Stevick Report, Appendix D.

[14] Stevick Report, Appendix B.

[15] Norton, R.L., Machine Design, an Integrated Approach, Prentice-Hall, 1998; ASME Boiler and Pressure Vessel Code, Section II, Part D, "Ferrous Material Specifications" American Society of Mechanical Engineers, New York: 1992 to 2010; Shigley, J.E., Mechanical Engineering Design, McGraw Hill, 3rd through 9th Editions, 1977-2010; Author's experience in failure analysis and design.

[16] Criteria of the ASME Boiler and Pressure Vessel Code for Design By Analysis in Sections III, and Section VIII, Division 2, American Society of Mechanical Engineers, 1969.

of near 1.0 for the DWH BOPs BSR for shearing centered pipe and preventing a massive oil spill.[17]

In the absence of a higher safety factor, additional shear tests could have been performed on the BSR to determine its capabilities. Cameron had the capability to do shear tests to determine whether a BSR can shear different types of pipe (i.e., 6-5/8 inch 27-pound pipe) in different positions and provides these tests for customers upon request.[18] But neither BP nor Transocean ever requested such tests for the DWH.[19]

B. Wrong Type of BSR was Used at Macondo

The DWH BOP was also not suitable for Macondo because it used the wrong type of BSR. The BSR in the DWH BOP was a Cameron shearing blind ram with a 15-1/4 inch single "V" shaped cutting blade.[20] The blade length of Cameron's DVS rams was maximized to increase shearing capabilities[21] and for the size of wellbore found at Macondo, the DVS blades would be about an inch wider than the cutting blade of the shearing blind ram used.[22]

The advantages of DVS rams over shearing blind rams was also noted by Cameron's Vice President of Engineering and Quality for the Drilling Systems Division who testified that *"a DVS gives you a wider range of shearability given a constant pressure."*[23] Cameron DVS rams suitable for use at Macondo were available at least as early as 2002.[24] BP or

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[17] It should be noted that if the ram blades are near full bore, an off-center pipe simply causes additional friction between the ram and cavity; the actual force required to shear is not significantly increased.

[18] Deposition of Jack Erwin, June 6-7, 2011, 136:12-23.

[19] Deposition of Jack Erwin, June 6-7, 2011, 136:24 - 137:2.

[20] Cameron EB 852D, p. 1 (Exhibit 7001).

[21] Cameron EB 852D, p. 6 (Exhibit 7001).

[22] Deposition of Melvyn Whitby, July 18-19, 2011, 352:13-19.

[23] Deposition of David McWhorter, July 7-8, 2011, 118:17-20.

[24] Cameron 2002 Replacement Parts Catalog, p. 108, BP-HZNBLY00366414.

Transocean could have upgraded the BSR to double "V" rams with wider blades and a more efficient shearing design, but they chose not to do so.[25]

Moreover, at least as early as 2005[26], Cameron's offered its CDVS rams with double "V" blades that cover the entire wellbore.[27] The existing DWH BOP could have been upgraded to replace the shearing blind ram with a CDVS ram.[28] Cameron's CDVS rams constituted BAST BSR rams on April 20, 2010 and would have successfully sheared the drill pipe and sealed the Macondo well if they were appropriately maintained and operated.

C. Wrong Number of BSRs were Used at Macondo

The DWH BOP was also not suitable for Macondo because the BOP only used one BSR. According to a Cameron BOP salesperson, Cameron's customers understood that more shear rams makes a BOP stack better.[29] Six-cavity BOP stacks that provided space for two BSRs were available from Cameron[30] and by 2009 or 2010, most of the rigs had two BSRs.[31]

At least as early as 2000, BP recognized that for dynamically positioned rigs such as the DWH:

> *"some operators have two sets of blind shear rams in order to have a backup seal in the event of an unplanned disconnect. The thought is to have one set to shear, and a second set to seal in the event*

[25] Deposition of Jack Erwin, June 6-7, 2011, 134:2-7.

[26] Deposition of Melvyn Whitby, July 18-19, 2011, 354:10-17; deposition of David McWhorter, July 7-8, 2011, 148:13-17.

[27] Deposition of Melvyn Whitby, July 18-19, 2011, 352:20 - 353:3.

[28] Deposition of David McWhorter, July 7-8, 2011, 147:18 - 148:12.

[29] Deposition of Jack Erwin, June 6-7, 2011, 52:11-16.

[30] Deposition of Jack Erwin, June 6-7, 2011, 134:15-18.

[31] Deposition of Jack Erwin, June 6-7, 2011, 62:2-14.

> *that the ram packer of the shearing ram is damaged."*[32]

A second BSR (particularly a BAST BSR such as Cameron's CDVS) would have significantly improved the ability of the DWH BOP to shear drill pipe and seal the well. The second BSR is particularly helpful in severe conditions, such as when there is a significant uncontrolled flow of hydrocarbons up the well, which is precisely the type of emergency where it is most important that the BOP is able to successfully seal the well. In that situation, even if the first BSR experiences erosion and is unable to completely seal the well, the hydrocarbon flow will be greatly reduced by the closing of the first BSR. This will virtually eliminate any damage potential to the second BSR from hydrocarbon flow, and will allow the second BSR to completely seal the well.

D. Wrong Control System was Used at Macondo

The failure to upgrade the DWH BOPs control system to the Cameron Mark III system available since 2006[33] is another example of how the DWH BOP was not suitable for Macondo. The Mark II control system used on the DWH BOP lacked the advantages of the improved Mark III system. Notably, the Mark II system used double coil solenoids (that could fail due to incorrect wiring) and batteries that were not rechargeable and the charge of which could not be monitored remotely.[34] But the improved Mark III control pods have single coil solenoids with higher pulling force that are not subject to incorrect wiring[35] and rechargeable batteries[36] whose charge can be monitored from the rig.[37]

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[32] Ex. 2390 (BP 2000 Well Control Manual) at BP-HZN-2179MDL00336682.

[33] Deposition of David McWhorter, July 7-8, 2011, 289:17-20.

[34] Deposition of David McWhorter, July 7-8, 2011, 290:1-4.

[35] Deposition of Jack Erwin, June 6-7, 370:14 - 371:6.

[36] Deposition of Jack Erwin, June 6-7, 367:18-22.

[37] Deposition of David McWhorter, July 7-8, 2011, 289:21-25.

E. Tandem Boosters Should have been Used at Macondo

Failure to implement Cameron tandem boosters on the DWH BOP also makes it unsuitable for Macondo. A Cameron Tandem Booster is an additional piston that can be fitted to the back of a shear ram bonnet to *"virtually double the shear force that can be brought to bear in that particular ram cavity."*[38] Cameron tandem boosters were available at least as early as 1998[39] and could have been added to the DWH BSR.[40] This would have greatly increased the shear force available to the BSR, and accordingly, the BSR's ability to shear drill pipe and seal the Macondo well.

Furthermore, BP was certainly aware of tandem boosters, and as early as 2005 had equipped the BOP for one of its other rigs with tandem boosters.[41]

F. Wrong EDS Program was Used at Macondo

Yet another example of how the DWH BOP was not suitable for Macondo is that the EDS system that was implemented did not specify closure of the CSR before the BSR. The DWH BOP implemented EDS-1, which was programmed to close the BSR and then disconnect the LMRP.[42]

Instead, BP and Transocean should have chosen to have Cameron program the available EDS that would cause the CSR to fire first and then fire the BSR (i.e., implement EDS-2).[43] Activating the CSR first provides the advantages of centering the drill pipe and reducing the flow of

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[38] Deposition of David McWhorter, July 7-8, 2011, 119:1-6.

[39] Cameron EB 852D, p. 10 (Exhibit 7001).

[40] Deposition of David McWhorter, July 7-8, 2011, 119:16-19.

[41] Ex. 4111 at BP-HZN-2179MDL01490429 (the BOP on BP's Thunderhorse included tandem boosters).

[42] Deposition of Jack Erwin, June 6-7, 30:1-9.

[43] Deposition of Jack Erwin, June 6-7, 2011, 135:6-10; deposition of David McWhorter, July 7-8, 2011, 225:13-24.

hydrocarbons up the well. Accordingly, EDS-2 is more likely than EDS-1 to successfully shear the drill pipe and seal the well.[44]

III. The Drill Pipe Was Off-Center When the BSR Closed

The failure of the BSR to seal the well was due to the drill pipe within the well being off-center.

A. Forensic Evidence Shows the Drill Pipe Was Off-Center

The drill pipe and BOP segments were retrieved from the well, and subjected to detailed inspection and documentation. It can be clearly seen in the photographs and laser geometry images of the drill pipe and the BSR shown below in figures 2 and 3 that the drill pipe was off-center when the BSR was activated[45].

[44] Deposition of David McWhorter, July 7-8, 2011, 226:10-25.

[45] Det Norske Veritas, Final Report for United States Department of the Interior Bureau of Ocean Energy Management, Regulation, and Enforcement, Forensic Examination of Deepwater Horizon Blowout Preventer, Contract Award No. M10PX00335, Volume I Final Report, Report No. EP030842, March 20, 2011 ("DNV Report Vol. I"), figures 41, 61. It should be noted that references and citations to the DNV Report and associated DNV documents and materials are intended as a reference to the underlying source evidence and data from DNV's post incident forensic investigation of the DWH, including the BOP.

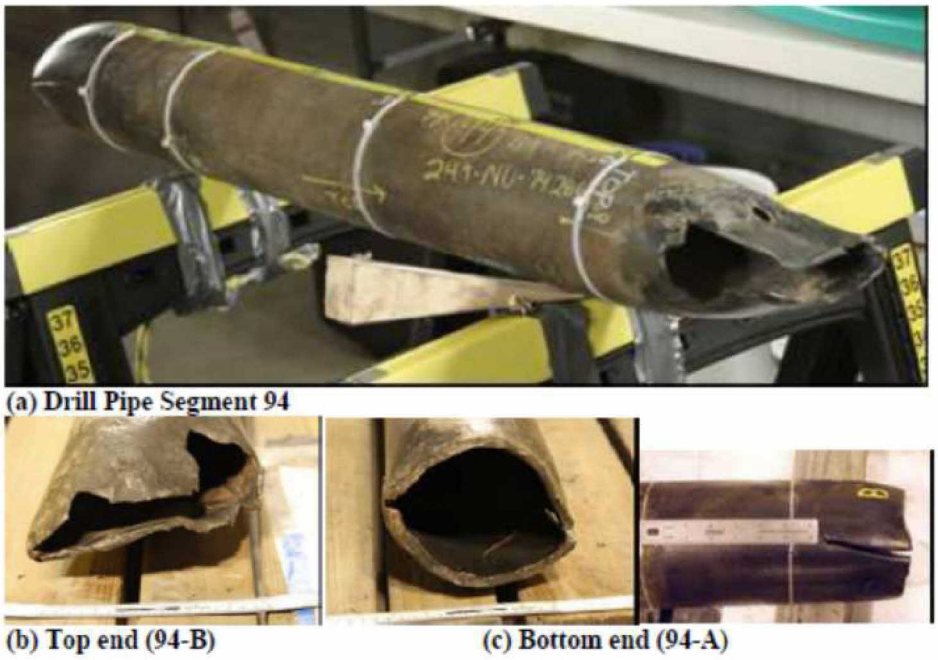

Fig. 2. Pictures of the drill pipe segment recovered from between the BSR and CSR, taken from the DNV Report.[46]

The above photographs of the drill pipe segment recovered from within the BOP and the below laser scan images of drill pipe segments and the BSR blocks show that the shapes of the severed ends of the drill pipe and the shapes of the deformed BSR blocks are consistent with the BSR closing on the drill pipe while the drill pipe was off-center.

B. Sufficient Force for Buckling Existed

KnightHawk concludes that expert calculations that show sufficient force for buckling are flawed.[47] I disagree. The buckling of the drill string probably began upon closure of the upper annular. This is prior to VBR actuation, and thus any friction at the VBR is not relevant at this stage. As the VBR closes (after the annular has been closed for an extended period of time, and has already been subject to erosion), the already buckled drill string will take on a new shape as the VBR begins to partially constrain the drill string. As the upper annular is closed, the velocity up the drill string

[46] DNV Report Vol. I, Figure 41.

[47] KnightHawk Report, p. 10.

dramatically increased. This is evidenced by the drop in hook load of approximately 60,000 lbs (and a corresponding increase in *upward* force on the drill string). Additional loss in hook load cannot occur as the tool joint is up against the upper annular and probably bouncing. Note that during the time of actuation of the VBR, the constraint of the VBR still allows complete rotation as well as some translation. This leads to required buckling loads that are significantly lower than the approximately 230,000 lbf suggested by KnightHawk[48], or the 130,000 lbf suggested by DNV.

Further, the VBRs cannot close instantly either. Prior to their complete closure, the drill string is already in its buckled state, forced to a position near the bore wall (kill side) in the BSR. At this time, even if friction were present between the VBR and the drill pipe, that friction would only act to hold the drill pipe in the buckled state even if the axial loads were to change. In actuality, the VBRs would unlikely be able to provide any significant axial constraint due to severe erosion. As the VBRs close, the annular flow being forced radially inward against the pipe and VBR packing material at near optimum erosion angles of attack.[49]

C. Contrary Expert Opinions are Not Well Founded

Shanks suggests the buckling was caused by the downward force resulting from the traveling block dropping following the explosion on the rig.[50] This theory gives another reason why off-center drill pipe must be considered even though it probably did not cause the buckling at the time of the BSR closure. There was almost certainly a downward force at some time caused by the traveling block coming down. As shown in the below pictures from DNV's forensic analysis, the curved plastic deformation of drill pipe section 39[51] and plastically deformed lower end, 39E[52] clearly indicate this section experienced high axial compressive loading from above.

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[48] KnightHawk Report at 10.

[49] Finnie, I., G.R. Stevick, and J.R. Ridgely, The influence of impingement angle on the erosion of ductile metals by angular abrasive particles, Wear, 152, 1992.

[50] Shanks Report, p. 34.

[51] DNV Report Vol. I, figures 51 and 52.

[52] DNV Report Vol. I, figures 51, 52, and 65.

(a) Drill Pipe Segment 39 (b) Top End (39-E) (c) Bottom End (39-F)

Fig. 4. Pictures of drill pipe segment 39, taken from the DNV Report.[53]

[53] DNV Report Vol. I, figure 51.

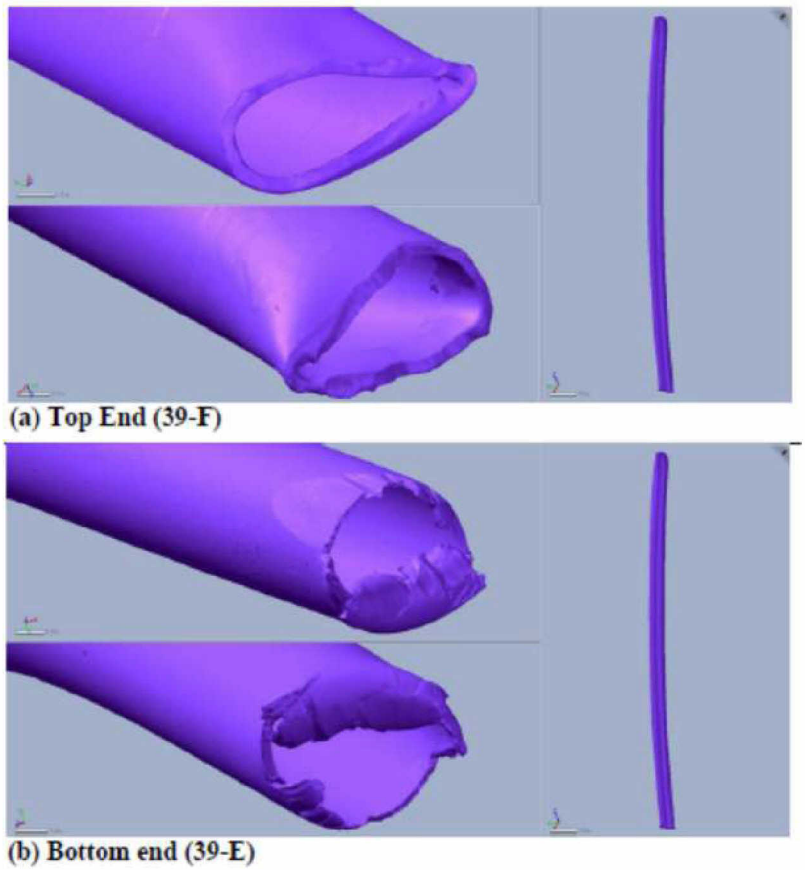


Fig. 5. Laser scan images of drill pipe segment 39, taken from the DNV Report.[54]

[54] DNV Report Vol. I, figure 52.

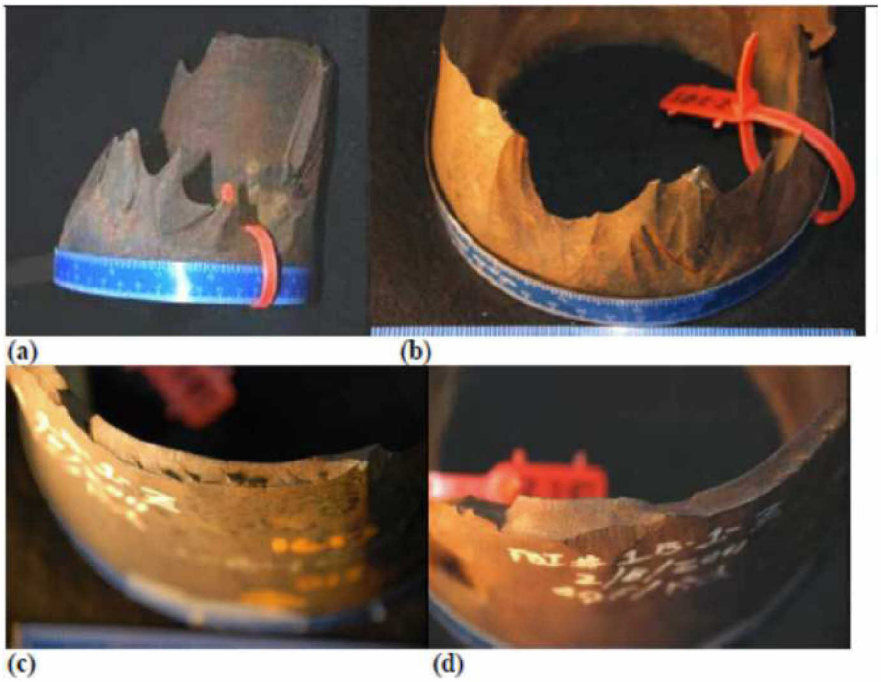


Fig. 6. Pictures of drill pipe segment 1-B-1-E, which is the matching end to 39-E, taken from the DNV Report.[55]

However, the plastically deformed lower end, 39E, is not reflected in or matched in its mating pipe section end, 1-B-1-E, just above the tool joint. As shown in the images of DNV's laser scan modeling, 1-B-1-E shows no such compressive plastic deformation.[56]

[55] DNV Report Vol. I, figure 65.

[56] DNV Report Vol. I, figure 68.

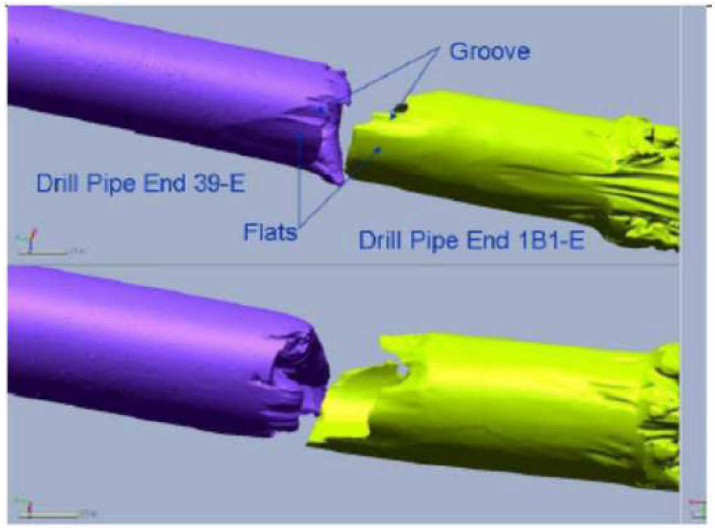


Fig. 7. Laser scan images of drill pipe segment 1-B-1-E and matching end 39-E, taken from the DNV Report.[57]

Thus, the high compressive load on pipe section 39 occurred after the pipe sections 1-B-1 and 39 had separated and had no continued load path downward to the BSR location. The bottom of section 39 was deformed as it was pushed downward into the top side of the upper annular away from its mating section of pipe.

The bending noted in section 1-B-1 is not particularly uniform indicating it occurred when it was located up in the riser where the riser bend occurred.[58]

[57] DNV Report Vol. I, figure 68.

[58] DNV Report Vol. I, figure 55.

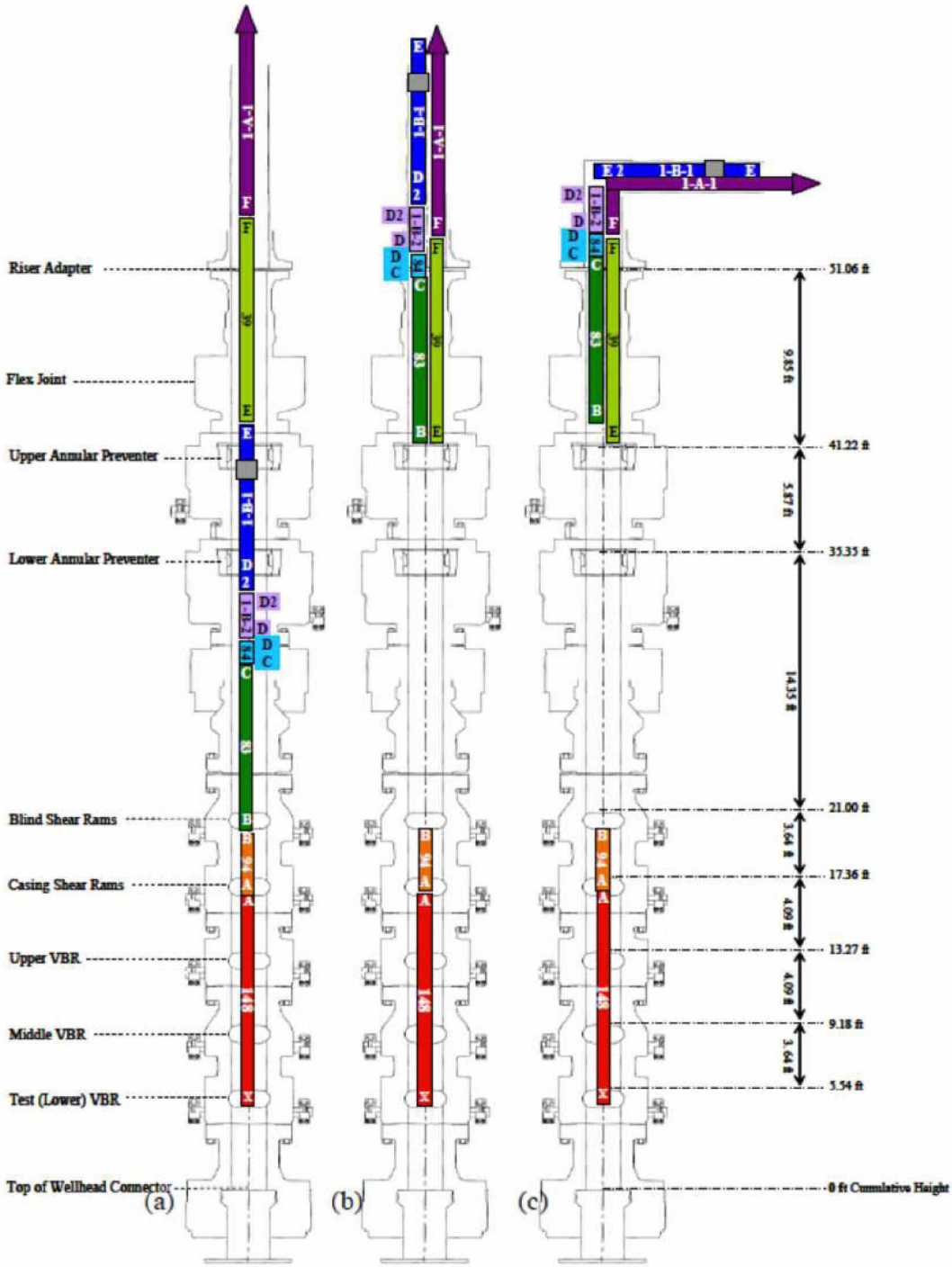


Fig. 8. Diagram of sequence of drill pipe segment movement from (a) prior to incident, (b) following break at point E and point B, and (c) following sinking of rig, taken from the DNV Report.[59]

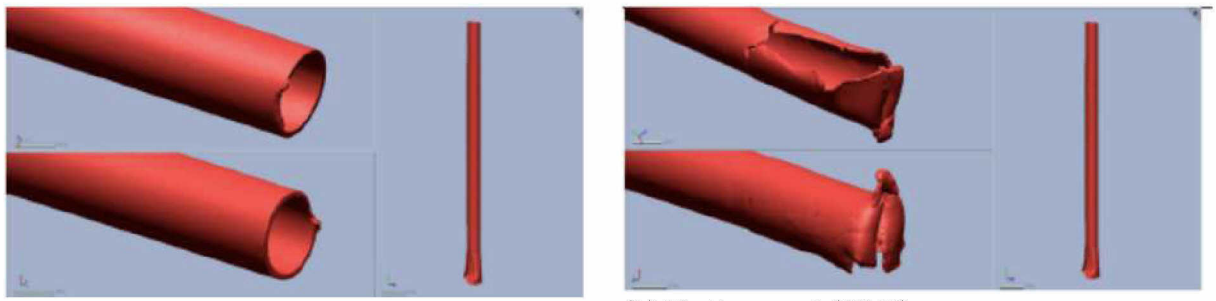
[59] DNV Report Vol. I, figure 55.

Section 83 just above the BSR also shows no curvature indicative of high compressive loading.[60]

(a) Drill Pipe Segment 83

(b) Top end (83-C) (c) Bottom end (83-B)

Fig. 9. Pictures of drill pipe segment 83, taken from the DNV Report.[61]



(a) Top end (83-C) (b) Bottom end (83-B)

Fig. 10. Laser scan model of drill pipe segment 83, taken from the DNV Report.[62]

[60] DNV Report Vol. I, figures 43 and 44.

[61] DNV Report Vol. I, figure 43.

[62] DNV Report Vol. I, figure 44.

In summary, high compressive loading due to the traveling block failure can and did occur. However, it did not compress or bow the pipe in the area of the BSR. The drill pipe above was already severed in the upper annular.

D. Knight's Criticisms of the Off-Center Drill Pipe Theories are Not Well Founded

KnightHawk concludes that the drill string buckling analysis done by DNV was inaccurate.[63] KnightHawk does not agree with the boundary conditions used by DNV, specifically that the VBR would provide only a pinned connection – KnightHawk believes that the VBR would provide a fixed condition where no translation and no rotation would be allowable. This would lead to buckling loads on the order of 230,000 lbf.[64]

KnightHawk also has its constraint directions upside down. Due to erosion, "hangoff" at a VBR would be impossible without a tool joint in or just above a VBR. This clearly did not occur. Hang-up at the upper annular by a tool joint clearly did occur. This assured constraint only supports buckling or bowing in the BOP by an upward force from below. The downward force theory lacks a lower end constraint preventing downward drill pipe movement while the drill pipe is still intact.

KnightHawk also states that even if the VBR would provide a pinned condition, the DNV calculations show that 95,550 lbs of force are available and 113,568 pounds are required for buckling, thus no buckling would occur.[65] However, this disregards the fact that those calculations are estimations, and the fact that they are of the same order of magnitude is sufficient (a DNV research engineer testified in his deposition that additional analysis would be required to get more accurate values, and that buckling could have occurred at 95,000, 120,000, or 70,000).[66] BEAR's calculations clearly support these lower values in modeling the drill pipe as

[63] KnightHawk Report, p.10.

[64] KnightHawk Report, p.10.

[65] KnightHawk Report, p. 10.

[66] Deposition of Neil Thompson, July 5, 2011, 191:17-23.

pinned-pinned or using the secant formula to account for pre-buckling and its resulting off-center loading.[67]

IV. The AMF/Deadman Failed to Activate the BSR Because of Transocean's Improper Maintenance

A. Transocean Let the Blue Pod 27V Battery Run Down

A Transocean expert concludes that the AMF/Deadman did, in fact, activate the BSR despite the existence of a depleted blue pod 27V battery and an incorrectly wired yellow pod solenoid.[68] I disagree. The available evidence leads me to conclude that the AMF/Deadman failed to actuate the BSR because of these two separate and independent failures that were both a direct result of Transocean's improper maintenance.

The 27 volt battery pack responsible for powering the two SEMs in the blue control pod registered charges of 1.1 volts and 1.0 volts in subsequent testing with no load.[69] This evidence strongly suggests that the blue pod 27 volt battery did not have enough charge to energize the blue pod solenoid valve at the time of the incident.

As manufacturer, Cameron recommended replacing the pod batteries after one year of use, at a minimum.[70] The control pod that was in use as the blue pod at the time of the incident, referred to as pod No. 3, had previously been the spare pod on deck since November 2007,[71] and was installed as the blue pod in April 2009.[72] The batteries in the blue pod (pod No. 3) had not been replaced since they were installed in 2007.

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[67] Higdon, A., et al, Mechanics of Materials, John Wiley and Sons, 3rd Edition, 1976.

[68] Childs Report, p. 24.

[69] DNV Report Vol. 1, p. 42, Table 5.

[70] Exhibit 3329 at TRN-MDL-01075694.

[71] Deposition of Jim McWhorter, April 20-21, 2011, 227:18-24.

[72] TRN-INV-01840853 (Exhibit 3980).

The undercharged 27 volt blue pod battery is unsurprising in light of Transocean's flawed condition-based maintenance program because the battery charge could not be measured remotely and therefore would not have been identified as a problem until the device failed during operation. In fact, this was not the first time that DWH pod batteries under Transocean's condition-based maintenance program had been found to have a low charge.[73]

B. Yellow Pod 103Y Solenoid Failed Because it was Incorrectly Wired by Transocean

Yellow pod solenoid 103Y was rebuilt in February, 2010 by Transocean personnel on the rig.[74] Post-incident testing by DNV determined that solenoid 103Y had one coil incorrectly wired at positions 3 and 4,[75] such that the two coils in the solenoid would create electromagnetic fields that would counteract each other.

[73] Exhibit 4305, p.54; Exhibit 3782; Deposition of Jim McWhorter, April 20-21, 2011, 191:4 - 193:12.

[74] Exhibit 3602 at CAM_CIV_0046705.

[75] DNV2011052708; DNV IMG_0458

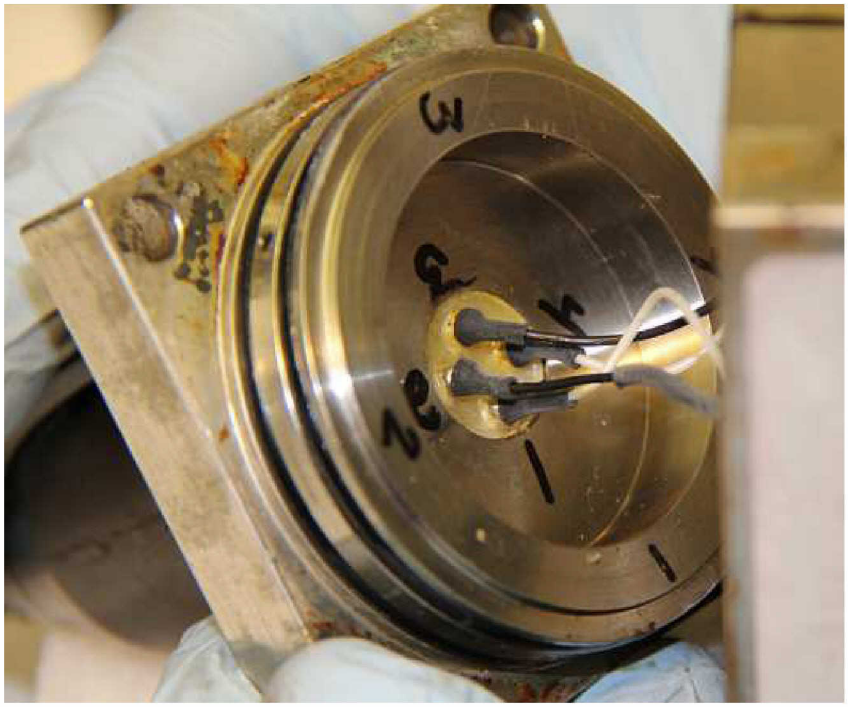

Figure 11. DNV IMG_0458, showing the solenoid coil positions, including positions 3 and 4 where the wires were reversed.[76]

Post incident DNV testing of solenoid 103Y and additional Cameron tests of other incorrectly wired solenoids have shown that an incorrectly wired solenoid such as 103Y is unlikely to activate. During DNV bench testing solenoid 103Y failed to activate either SEM from the yellow control pod when both solenoid 103Y coils were energized via a 24 volt DC power source.[77]

DNV performed additional testing on solenoid 103Y where a SEM controller was used to power 103Y instead of the 24 volt DC power source. There was initially some confusion regarding these tests because DNV did not understand how different Portable Electronic Testing Units (PETU) worked.[78] DNV later discovered that use of the PETU to activate one SEM

[76] DNV IMG_0458.

[77] DNV Report Vol. 1, p. 44; Exhibit 5172, p. 6.

[78] DNV2011060743.

would sometimes activate both SEMs, and some tests designed to activate both SEMs only activated one.[79] The correct interpretation of these test results in light of this information is that when both SEM A and SEM B simultaneously activate a dual-coil solenoid, that solenoid did not function properly in 3 out of 4 tests.

A September 2010 Cameron test report showed that incorrectly wired dual-coil solenoids would not function properly when used in an actual control pod.[80] This testing showed that the incorrectly wired solenoids functioned properly when one coil was activated, but did not function when both coils with opposite polarities were activated. As a result, Cameron determined that opposite polarities in the two coils of a solenoid *"will not allow it to function when both coils are energized."*[81]

The incorrectly wired yellow pod solenoid 103Y is unsurprising in light of Transocean's flawed condition-based maintenance program because the incorrect wiring could not be measured remotely and therefore would not have been identified as a problem until the device failed during operation.

C. AMF Failed to Actuate Because of these Two Failures

The BOP had redundant yellow and blue control pods, but required at least one control pod to be operational in order to execute the AMF function. As described above, the blue control pod failed to properly actuate and energize the solenoid valve because of the greatly depleted charge of the 27 volt battery. The yellow control pod failed to properly actuate because the coils of incorrectly wired solenoid 103Y created electromagnetic fields of opposite polarity that cancelled each other out. As a result, the AMF failed to actuate because of these defects in the blue and yellow control pods that were not identified by Transocean's condition-based maintenance.

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[79] DNV2011060642; DNV2011060643.

[80] CAM_CIV_0374340-49.

[81] CAM_CIV_0374340-49 at CAM_CIV_0374341.

D. Transocean's Theories are Inconsistent with the Evidence

Transocean expert Mr. Childs concluded that yellow pod solenoid valve 103Y functioned properly during the blowout.[82] Mr. Childs acknowledges that solenoid 103Y was incorrectly wired, but argues that the incorrect wiring did not impact solenoid 103Y's functionality at the time of the incident.[83] This opinion is not well founded and I disagree.

Mr. Childs based his conclusion on the argument that the Phase I and Phase II testing performed by DNV shows that incorrectly wired solenoid 103Y worked when connected to a SEM. But this argument does not take into consideration the problems with the Cameron PETUs and DNV's misunderstanding of how they worked. As described above, DNV's initially misunderstood the operation of the PETUs, and DNV's intended use of the PETU to activate one SEM would actually activate both SEMs, and vice-versa.[84] Childs does not address this issue, which contradicts his argument. The proper interpretation of the DNV test data in light of this issue is that an incorrectly wired solenoid is unlikely to function properly when both SEMs are activated, as happens in practice.

V. BP Was Actively Involved in the Design of the BOP and did not Exclusively Rely on Transocean and Cameron for the BOP

A BP expert has suggested that the responsibility for the design of the BOP only fell on Transocean and Cameron[85] and that BP merely relied on the Cameron BSR to seal the well in an emergency.[86] I disagree. The documents and testimony lead me to conclude that BP was intimately involved in the design, build, and testing of the DWH BOP.

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[82] Childs Report, p. 33.

[83] Childs Report, p. 33.

[84] DNV2011060642; DNV2011060643.

[85] Shanks Report, p. 10.

[86] Shanks Report, p. 7, 11.

A. The Well Operator is Responsible for the BOP and Along with the Drilling Contractor is in the Best Position to Determine the Necessary BOP Capabilities

BP is a sophisticated Operator with substantial engineering talent and the most information about the Macondo well and the conditions in which the BOP must be able to function. BP and Transocean (as Drilling Contractor) were in the best position to determine what BOP capabilities were needed and what BSR technology was required. Moreover, as Operator at Macondo, BP is ultimately responsible for the DWH BOP.[87]

Transocean's Manager of Subsea Engineering Well Control Systems[88] confirmed that the Operator and Drilling Contractor for a specific well are better suited than the BOP manufacturer to make decisions regarding the appropriate BOP configuration for that well because the Operator and Drilling Contractor have more information about the well.[89]

B. BP Was Actively Involved in the DWH BOP Design, Including Specifying the BOP Stack and the Rams Used

According to Cameron's Vice President of Engineering and Quality for the Drilling Systems Division, it is common for an Operator and a Drilling Contractor to *"take the lead in configuring the BOP stack."*[90] Indeed, this was the case with the DWH BOP stack, where *"BP was involved in the configuration of that BOP from the beginning,"*[91] and *"BP played an active role in specifying that stack."*[92] BP, including through its predecessor Vastar, specified the configuration of the BOP stack and the types of rams

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[87] Code of Federal Regulations Title 30 Part 250 Oil and Gas and Sulphur Operations in the Outer Continental Shelf, Subpart D ("30 CFR § 250"), Section 250.400, et seq; American Petroleum Institution Recommended Practice 53: Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells ("API RP 53").

[88] Deposition of Robert Turlak, September 28-29, 2011, 26:23 - 27:5.

[89] Deposition of Robert Turlak, September 28-29, 2011, 384:1-12.

[90] Deposition of David McWhorter, July 7-8, 2011, 592:7-18.

[91] Deposition of David McWhorter, July 7-8, 2011, 591:9-11.

[92] Deposition of David McWhorter, July 7-8, 2011, 331:2-3.

used.[93] Moreover, the Drilling Contract between BP's predecessor Vastar and Transocean's predecessor Falcon specified the model for the rams.[94] Ultimately, it was BP that decided what the BOP stack configuration would be and specified the location and types of rams used.[95]

C. BP Knew or Should Have Known the BSR was a Shearing Blind Ram that was Unable to Shear Off-Center Drill Pipe

A BP expert suggests that BP simply relied on the Cameron BOP and its BSR to seal the well in an emergency.[96] But the same expert also recognizes that the BSR was unable to shear the drill pipe and seal the well because the drill pipe was off-center.[97] BP is a sophisticated Operator and either knew or should have known that the BSR used in the DWH BOP did not have blades that extended the entire width of the well bore and did not have double "V" blades, meaning that the BSR may be unable to shear off-center drill pipe even in situations where the BSR would otherwise be able to shear centered drill pipe.

The 1999 DWH BOP purchase order between Transocean predecessor Falcon and Cameron specifies that the BSR will be a shearing blind ram with Cameron part number 2163096.[98] BP produced a copy of the purchase order, which establishes that it was in BP's possession. A 2000 position paper prepared for BP predecessor Vastar by an outside consultant addressed the "[o]verall design of the BOP Stack for the Deepwater Horizon"[99] and refers to "[s]hearing blind rams" in the "[u]pper

[93] Exhibit 4112 at BP-HZN-MBI00021537 - BP-HZN-MBI00021539; deposition of Michael Byrd, July 13-14, 2011, 488:12-494:18.

[94] Exhibit 4112 at BP-HZN-MBI00021538; deposition of Michael Byrd, July 13-14, 2011, 488:18 - 489:1.

[95] Deposition of Anthony Hayward, June 6 and 8, 2011, 537:1-13.

[96] Shanks Report, p. 7, 11.

[97] Shanks Report, p. 29.

[98] BP-HZN-BLY00052579 at BP-HZN-BLY00052636.

[99] TRN-HCEC-00026736 at TRN-HCEC-00026928.

ram cavity," i.e., the BSR position.[100] Thus, BP knew or should have known that shearing blind rams with blades that did not cover the entire wellbore and did not have two "V" shaped cutting blades were being used for the BSR.

VI. Summary Of Key Findings

The DWH BOP was subject to a number of design flaws and failures to implement BAST, which made the DWH BOP inappropriate for the Macondo "well from hell," including the failure to use a BSR that could shear off-center drill pipe. The Macondo drill pipe was off-center at the time the BSR was activated, and off-center drill pipe was well known and foreseeable. The AMF/Deadman function failed to activate because Transocean's flawed condition-based maintenance program allowed the 27 volt blue control pod battery to lose its charge and the yellow control pod solenoid 103Y to be incorrectly wired without identifying these problems. Finally, BP was actively involved in the design of the BOP and did not rely solely on Transocean and Cameron for the BSR. I disagree with all of the experts who conclude otherwise.

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 January 17, 2012

Dr. Glen Stevick, P.E.

[100] TRN-HCEC-00026736 at TRN-HCEC-00026930.