Expert Report – Macondo Phase II

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Engineering Partners International

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TREX-011464R.1

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BP's Macondo Well Blowout –Phase II Report
"Efforts Expended to Suppress the Flow of Hydrocarbons from the Macondo Well" by Gregg S. Perkin, P.E. of Engineering Partners International, LLC

BACKGROUND:

In April, 2011, Engineering Partners International, L.L.C. ("EPI") was retained by the Plaintiffs' Steering Committee ("PSC") with regard to the April 20,2010, well control event and the subsequent blowout of BP's deepwater offshore exploratory well, OCC-G32306 Mississippi Canyon MC 252 #1 ("Macondo"). Macondo was drilled in a water depth of approximately 4,992 feet in the Gulf of Mexico ("GoM").

EPI's Gregg S. Perkin, P.E. had been retained by the PSC to address specific issues with regard to the subsea Blowout Preventer ("BOP") utilized on Macondo. Certain events which occurred prior to the blowout and subsequently up to the time of the blowout have been referred to as **Phase I**. For **Phase I**, I was asked to review and analyze issues pertaining to this BOP's use on Macondo with respect to its:

1. Design;
2. Configuration;
3. Modifications;
4. Testing;
5. Maintenance and;
6. Use of the Best Available and Safest Technology ("BAST").

For **Phase II**, EPI was asked to review and analyze all of the available facts and evidence pertaining to the planning, preparedness, activities, and equipment; to include its availability, staging, assembly and utilization undertaken during **Phase I** and during **Phase II** by BP [redacted] to cap and contain the uncontrolled flow from BP's Macondo.

Each of the opinions I express in my **Expert Report** are based upon my education, training, knowledge and experience in the areas of mechanical engineering and the design, application and use of oilfield equipment, such as blowout preventers ("BOPs") and their control systems ("CS"), used in both onshore and offshore oil and gas drilling and operations.

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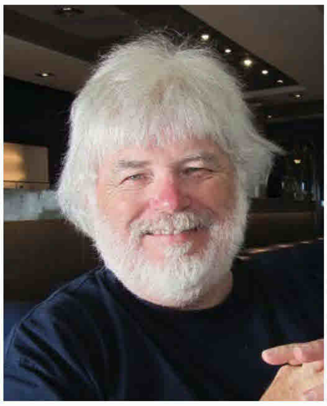
My expert opinions and engineering conclusions were founded upon all of the information and materials which I have reviewed. They are also based upon certain regulatory requirements governing offshore oil and gas exploration, drilling and production including industry standards and recommended practices. I am familiar with these particular regulations, standards and recommended practices for the relevant time frame between 2001 to the present.

These materials are relied upon in the ordinary course of business by Oil & Gas Well Operators, such as BP, and their working interest owners who drill and complete deepwater wells in the GoM. I have not been asked to make any assumptions, nor have I presumed any facts beyond those which are evidenced by the reliance materials identified in this **Expert Report.**

AUTHOR INTRODUCTION & QUALIFICATIONS:



Gregg Perkin has been involved in oil and gas drilling equipment design and oilfield operations since 1968. He has authored technical papers on equipment design, well control and oilfield safety including having developed a number of equipment and systems patents.

While in college, he was employed by a major oil and gas service company. In 1973, he graduated with a Bachelor of Science in Mechanical Engineering from California State University at Long Beach. He became a registered Professional Engineer by examination in the State of California in 1978 and is currently registered as a Professional Engineer in good standing by examination, experience & comity in thirteen (13) states including Louisiana.

Mr. Perkin's Oilfield Service Industry experience included working as a Design Engineer, Engineering Manager, Manager of Technical Services, Chief Engineer, Vice President of Engineering and also as a Director of Manufacturing. Mr. Perkin also worked as a Roughneck or Floorman and Derrickman on an onshore drilling rig and as Serviceman and Field Engineer in both offshore and onshore drilling and completion operations.

In mid-1987, Mr. Perkin began work as an independent professional mechanical engineering consultant. In 1995, Mr. Perkin co-founded Engineering Partners International, L.L.C. ("EPI"). Mr. Perkin is presently employed by EPI as its President and also as an independent consultant and Professional Engineer in the areas of domestic and international onshore and offshore Oil & Gas Drilling and Production operations including the design, use and application of the equipment and systems used in oilfield exploration.

While at EPI, Mr. Perkin has been retained to conduct product design analysis, equipment design, perform failure analysis, review claim elements of intellectual property and provide other independent engineering consulting services related to mechanical equipment and systems including the design, application, use, testing of BOPs and their related CS used both onshore and offshore. Mr. Perkin's full *curriculum vitae* and other biographical materials are attached as **Appendix B**.

Respectfully Submitted:

Gregg S. Perkin, P.E.
President and Principal Engineer
Engineering Partners International, L.L.C

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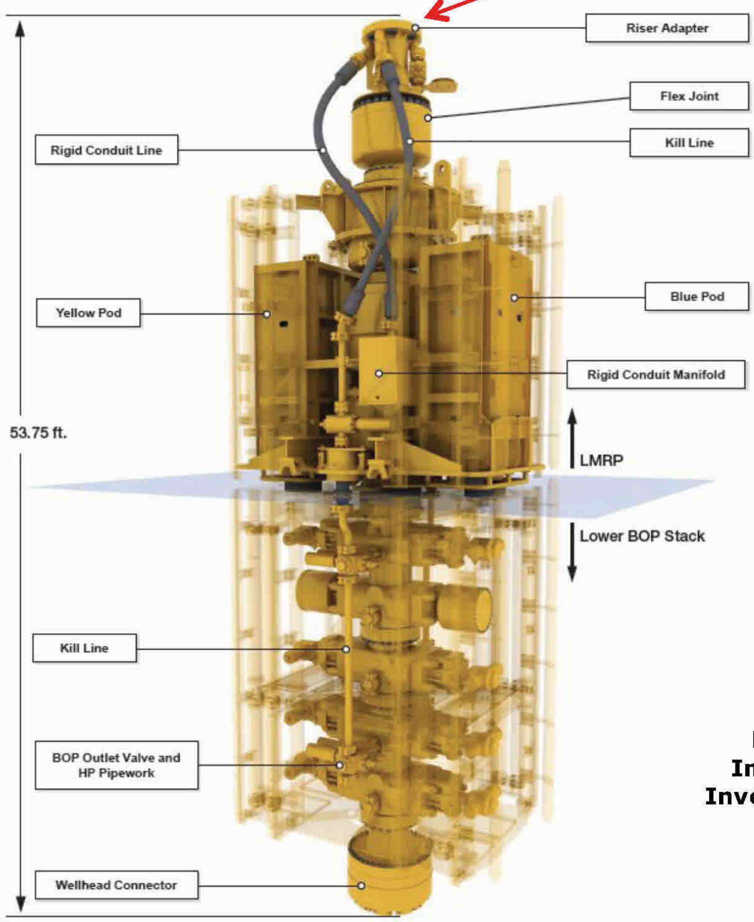
Based on my education, training, knowledge and experience in oilfield equipment design, application and use in oilfield operations, such as Deepwater drilling operations, and based upon the information I have reviewed and the work I have conducted, I presently have found the following to be true, supplemented and explained in the remainder of this Expert Report.

EXECUTIVE SUMMARY:

The flow of hydrocarbons and other constituents which uncontrollably discharged into the GoM from BP's Macondo Well was halted on July 15, 2010 utilizing a 3-Blind Ram Capping BOP Stack ("Capping Stack"). This Capping Stack was installed at a Riser Adapter connection atop the original Macondo BOP's Flex Joint. Refer to the Image below.

Note: The Capping Stack was connected here after the Riser was removed.



**LMRP & Lower BOP Stack
Image Source: Transocean's Investigation Report June, 2011**

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Capping Stack solutions to contain unrestrained flow from an oil and gas well were a known technology prior to Macondo. Capping Stacks are used in both onshore and offshore blowout emergencies.

The design, assembly, application and use of a subsea Capping Stack has been a common industry topic with regard to subsea Drilling Operations. In fact, a Joint Industry Study in 1991 provided a nearly exact diagram of the Macondo Incident and offered solutions such as Capping Stacks for responding to such an event.[1]

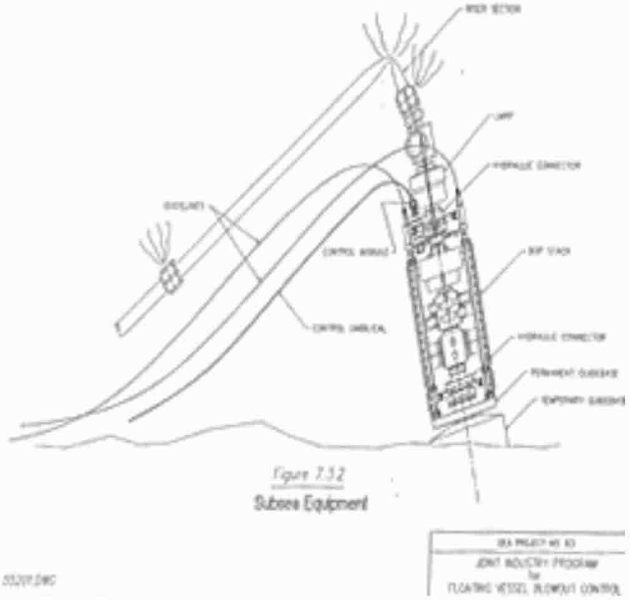

Figure 7.32
Subsea Equipment

However with regard to Macondo neither BP [redacted] made any diligent efforts or expended any funds to determine how Deepwater Capping technology could be utilized in the event Macondo or any other deepwater well blew out.[2] As Macondo flowed uncontrollably, a Capping Stack solution was not available. Had a properly designed and assembled Capping Stack been available for BP's Macondo Well prior to this incident, the uncontrolled flow of hydrocarbons could have been arrested in a matter of weeks.

After the blowout occurred, well control experts from Wild Well Control, Inc. ("WWCI"), TO and Cameron advised BP of courses of action to take to shut-in and seal the well. A BOP-on-BOP capping procedure was made available and recommended for implementation to BP. Yet BP chose to prioritize a different intervention technique known as a Top Kill. The Top Kill consisted of pumping a

[1] Joint Industry Program for Floating Vessel Blowout Control, Final Report, DEA-63 (1991) at 7.13 – 7.24.

[2] Deposition Testimony of Andy Inglis at 162 (July 21, 2011); TREX 9104

large and heavy volume of fluid at a high rate of flow ("Momentum Kill") along with various items ("Junk") which could plug any voids and/or openings in the flow's path. This was referred to as a Junk Shot. The success of either or both methods was risky because many parameters pertaining to the uncontrolled flow from their Well was unknown, not well understood, and/or withheld by BP. Some of the direct parameters included the flow rates, pressures and the flow's make-up including any resistance to flow. Indirect Top Kill parameters included risks and hazards such as:

1. Bursting rupture disks in the 16" OD Casing;
2. Potentially and negatively impacting the drilling of the Relief Wells and;
3. Subsea and surface equipment damage. For example, any catastrophic failure of the high pressure and flow surface equipment used in the Top Kill could risk the lives of the people conducting the Top Kill work.

BP knowingly accepted these risks and chose a Top Kill option prior to pursuing the Capping Stack or BOP-on-BOP solution as had been recommended by others.

The Top Kill effort subsequently failed as BP knew it would. BP deliberately misrepresented the reasons for its failure.[3] For example, instead of informing the Unified Command of the true reason(s) for the Top Kill's downfall, i.e., high flow rate and the actual size of the opening(s) inside the BOP from where the flow was discharging, BP misrepresented that the Top Kill failure was caused by the bursting of the rupture disks in the 16" OD Casing.

However, no such bursting occurred. BP's Top Kill misrepresentations directly led to the discontinuation of the BOP-on-BOP solution and further delayed the option of a Capping Stack solution. Meanwhile, BP's Macondo Well continued to flow uncontrollably.

[3] TREX 9084; TREX 9163.

FINDINGS

BP's Pre-Incident Knowledge:

1. BP Management knew that certain deepwater well control events could lead to a deepwater blowout. Given these possibilities with regard to its Macondo Well, disastrous consequences would follow if the BOP failed to shut-in and seal the Well;
2. BP Management knew that subsea BOPs were not fail-safe. For example, it was possible and foreseeable that a subsea BOP which was actuated to control a flowing well could fail to control it;
3. BP Management knew or should have known that ROV intervention was not a timely and reliable intervention technique to actuate a BOP subjected to dynamic flow conditions;
4. BP Management was aware that secondary well control intervention technology and equipment, such as Capping Stacks, existed prior to their Macondo Well blowing out. Before Macondo's drilling operations began, BP Management should have had a deepwater Capping solution, including a back-up BOP readily available;
5. As part of a meaningful and realistic Capping solution, BP Management should have had all of the necessary equipment sourced and readily available to them;
6. Absent having a meaningful secondary well control intervention solution of any kind available to them, BP Management continued to drill Macondo knowing that its BOP could potentially fail to shut-in and seal the Well.

BP's Post-Incident Knowledge:

1. BP Management knowingly misrepresented Macondo's flow rate from (a) certain government officials and (b) knowledgeable contractors, OEMs and consultants;
2. BP Management proceeded with the Top Kill. BP represented that it had a high probability of success. However, Macondo was uncontrollably flowing in excess of 15,000 barrels of oil per day – a rate at which BP knew the approved Top Kill procedure could not succeed;
3. BP Management knew that Junks Shots were rarely successful;
4. BP Management knew that the BOP-on-BOP solution had a higher probability of success with a corresponding lower risk of failure as a secondary well control intervention method;
5. After the failure of the Top Kill, BP Management represented that the most probable reason for its failure was that the constituents that made-up the Top Kill exited through the burst rupture disks. BP Management knew that the reasons for its failure were the flow rate and the various inside diameters of the wellbore, and BP failed to disclose that reasoning, and;

6. BP Management misrepresentations and omissions regarding Macondo's uncontrolled flow rates were the basis for a conscious decision to discard the BOP on BOP solution and caused a delay in the Capping Stack efforts. This resulted in the continued and uncontrolled flow from the Macondo Well for a significantly longer period than necessary.

[redacted]

[redacted]

[redacted]

TREX-011464R.10

BACKGROUND AND DISCUSSION OF THE EFFORTS EXPENDED TO SUPPRESS THE FLOW OF OIL FROM THE MACONDO WELL:

On April 20, 2010, at 21:51 CDT, an explosion occurred on TO's DEEPWATER HORIZON Mobile Offshore Drilling Unit ("MODU") located in the GoM approximately 42 miles southeast of Venice, Louisiana.[5] At that time, BP activated its **Oil Spill Response Plan** ("OSRP") for the Macondo and began assembling resources both inside and outside of BP to respond to this incident.[6]

1. *It was foreseeable that certain deepwater well control events could lead to a deepwater blowout.* [redacted]

[redacted] Issues surrounding the adequate shutting-in and sealing of a deepwater well under dynamic flow conditions were foreseeable by both BP and TO but neither took steps to achieve the capability to effectively and quickly respond. [8]

BP Management relied solely on TO's BOP and CS for well control. BP's only readily available intervention options in response to this event were to use ROV intervention or drill a relief well.[9] A relief well would be an offshore rotary drilling process believed to take up to 150 days.[10] [redacted]

After the incident, BP Management formed multiple teams comprised of various industry personnel; each focused on different ways to either stop the flow of hydrocarbons or collect them at their source. BP had no tested techniques available to them for the source control of a deepwater blowout such as Macondo.

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[5] Stipulated Facts Concerning Source Control Events, Rec. Doc. No. 7076 (August 9, 2012).

[6] *Id.*

[7] Deposition Testimony of James Wellings, Jan. 16-17, 201317:3-7 "*When a BP well plan is put together for an exploration well, there was no planning for a response to the inability to shut-in a well during a blowout.*"

[8] TREX 10166, "*The immediate focus of our operational activities it to work through alternative plans to attempt to shut off the flow of oil permanently. Ultimate resolution will require the drilling of a relief well...April 26, 2010...Engineering and some initial fabrication work has begun to develop subsea collection systems...whilst similar systems have been used in shallower waters, this will be the first time such an approach has been attempted at these water depths.*"

[9] TREX 769; TREX 8886; TREX 10166; Deposition Testimony of Tony Hayward, June 6-7, 2011 at 255-256.

[10] TREX 10526; TREX 2291; Interview with Doug Suttles, October 13, 2010.

BP has acknowledged they had no pre-built equipment or written source control procedures for an uncontrolled deepwater blowout. [11]

BP's response to their spill in the GoM was to primarily concentrate on dealing with the floating oil at the surface rather than any type of subsea intervention.[12] BP was clearly stumbling in their response to this emergency. They had no meaningful secondary intervention solution and associated equipment readily available for a worst-case well control event.[13] BP [redacted] knew that "extended delivery schedules affect deepwater equipment availability" and that "ram preventers and subsurface equipment [are] a scarce commodity."[14] Neither BP [redacted] acted to remedy these issues prior to the Macondo incident.

During Macondo's emergency source control response, all final source control recommendations with regard to secondary intervention were made by BP.[15] While the Unified Area Command ("UAC") had technical approval authority, the UAC authority functioned more as a veto power.[16]

After the blowout, BP Management's focus was on efforts to close the Ram-Type Preventers using ROV intervention.[17] ROV intervention was stand-alone only. For well control purposes, certain ROV's were equipped with a hydraulic pump. The ROV had the ability to insert a male quick-disconnect stab ("Hot Stab") into a female Hot Stab connection to actuate a BOP element.[18]

Pumping capacities of ROVs are extremely limited and slow.[19] BP Management knew that the uncontrolled flow from Macondo would result in the erosive damage to the elastomeric sealing elements used on the Ram-Type preventers they tried to close. In order to shut-in and seal-off Macondo, the elastomers needed to be uncompromised.[20]

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[11] *Id.*
[12] TREX 2291, p. 5; TREX 7346, p. 53; Deposition Testimony of Tony Hayward, June 6-7, 2011 at 256.
[13] Deposition Testimony James Rohloff, October 17, 2012, 51:3-12, 56:11-17.;
[14] TREX 7353.
[15] TREX 9105; TREX 9099; TREX 9125.
[16] Deposition Testimony of Pat Campbell at 349-350.
[17] Stipulated Facts Concerning Source Control Events, Rec. Doc. No. 7076 (August 9, 2012) at ¶¶ 23—52; An ROV is a submersible vessel that is controlled via an electrical umbilical from the drilling rig. Based upon the equipment installed and the tools it carries, the ROV can operate certain hydraulic or mechanical BOP stack functions, surveillance, and replacement of gaskets subsea. It is equipped with video cameras and lights.
[18] TREX 1166, pg. 15, 3.3.3.8 ROV Intervention.
[19] TREX 1166 at 66, 82-83, 5.1.7.2, 6.10.
[20] TREX 4423.

BP knew this as early as 2001[21]:

Situation:

- Horizon has driven off
  Well is flowing at 100,000 - 300,000 bbls / day
  BOP is open - no rams closed
  Do not know if Dead-Man has actuated or not
  ROV flow rate for override is 0.12 GPM

Question:
Can we close the shear rams with ROV over-ride without further damage to the BOP at 100, 200, & 300BPD flow rate

Answer:

- No. Closing the shear rams at any of the above flow rates will probably cause them to wash out. One has to assume given that rate, there is a lot of sand being transported as well which only accelerates the erosion process. No one on my team was available at WL1. Vern, located at Mustang Eng., and I discussed the situation and came to this conclusion.
- We have since spoken with Cameron and others and offer the following;

Further, response times for ROV deployment typically permit uncontrolled flow rates to change.[22] At high flow rates, large amounts of sand and debris are constituents of the flow. At high flow rates, erosion to surfaces within the BOP increases. Erosion decreases the likelihood of the BOPs capability to shut-in and seal a flowing well.[23]

[redacted]

[redacted]

As soon as control of the Well was lost, secondary well control intervention systems should have been available and utilized in the event that the primary BOP and its CS were lost. To be useful, these systems must be readily available. Clearly, BP had nothing available and had not considered any meaningful secondary well control intervention systems prior to Macondo blowing out. Had BP done so, BP could have deployed a capping solution during the three (3) weeks that they were attempting to deploy their ineffective ROV solutions.

Because BP had no such equipment or procedures readily available, BP had to create the equipment and devise procedures from scratch. It did not have all of

[21] Id.
[22] TREX 1166 at 66, 82-83, 5.1.7.2, 6.10.
[23] *Id.* pg. 25, 4.3 Response Time.
[redacted]
[26] TREX 2291, Pg. 138-139.

the tools it needed in the toolkit.[27] BP was attempting to develop parallel intervention alternatives. It was primarily considering two (2) options beyond the relief well and ROV intervention. One option focused on using another MODU's BOP: the BOP-on-BOP option. The second was a Capping Stack solution that would be connected to Macondo's BOP. Both options are similar. A BOP from another MODU would need to be available to BP. Generally, the means to connect it to Macondo's BOP and then operate it would need to be determined. The general procedure for removing the LMRP and landing a new BOP was understood.[28] A Capping Stack solution had similar challenges.

Despite the fact that BP should have analyzed and considered both options prior to April 20, 2010, BP never tested or attempted to implement either of these technologies in a deepwater well control scenario.[29]

As discussed, subsea intervention devices like Capping Stacks were known to BP [redacted]. When properly designed and configured, Capping Stacks have been proven to positively function in order to contain uncontrolled and flowing wells in both the onshore and offshore oil & gas drilling industry.

A Capping Stack is essentially a smaller version of a BOP Stack designed to connect to the top of the BOP stack. Based on its requirements, the Capping Stack can be configured with a minimum of two (2) or three (3) Blind Rams. The lowest Blind Ram would be actuated 1st followed by the 2nd Blind Ram and then, if available, the 3rd. If the 1st Blind Rams fail to shut-in and seal the uncontrolled flow after closure, they protect the 2nd set of Blind Rams. If a 3rd set of Blind rams is included, their closure is protected by the 1st and 2nd set of Blind rams.

The use of Choke and Kill lines below the Blind Ram assemblies in a Capping Stack solution:

- Allow for drilling fluids to be pumped into a flowing well through the Kill Line;
- Allow for any fluids, solids and gasses in the wellbore to be circulated out of it in a controlled manner through the Choke Line;
- Permit the use of both the Choke and Kill Lines to be simultaneously used to communicate with the wellbore and;
- Allow the pressure in the wellbore to be throttled and/or controlled[30]

As such, a Capping Stack solution for Macondo was not a technological innovation. For example, in 2001, BP Alaska ("BPAX") identified the capping of a well, which

[27] Deposition Testimony of Tony Hayward at 343.
[28] TREX 11402.
[29] TREX 769; TREX 8886; TREX 10166; Deposition Testimony of Tony Hayward, June 6-7, 2011 at 255-256; Deposition of James Rohloff, October 17, 2012 at 33-34, 47-49
[30] TREX 7107

was flowing uncontrollably through its existing BOP, as the Best Available Technology to contain it. BPAX recognized that certain well capping techniques, which had been applied to both land and offshore locations had historically proven to be successful in regaining well control in shorter durations.

As a result, BPAX preferred Capping Stack solutions over the more time-consuming alternative of drilling a relief well.[31] BP never attempted to convert this Best Available Technology for use in their deepwater Macondo operations. [32] BP's failure was in the face of multiple warnings that such measures were necessary.

[redacted]

[redacted]

Despite BP's failure to design, assemble, test and make-ready subsea intervention solutions for its deepwater drilling operations, BP continued its reliance upon a procedure that it knew would likely fail to reasonably mitigate a subsea blowout; ROV intervention. Had BP considered and planned for the worst-case scenario, BP would have had a means to shut-in and seal its Well from discharging hydrocarbons into the GoM weeks before it was finally capped on July 15.[35]

The BOP-on-BOP option was a front-runner option as early as May, 2010.[36] WWCI, recognized in the industry as a premier emergency well response company, was involved with a number of source control efforts. By April 27, WWCI had provided BP with a BOP-on-BOP remedy for Macondo.[37] Their procedure landed an existing BOP Stack atop Macondo's BOP after removing its LMRP.[38] In fact, in a 1991 **Joint Industry Program**, BP was advised that:

"...it may be desirable to remove all [pressure containing equipment on the wellhead] and leave the wellhead completely exposed."[39]

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[31] TREX 9171; TREX 9346; Trex 9827; TREX 9828; BP-HZN-2179MDL01428028 – BP-HZN-2179MDL01428044; TREX 9552; TREX 5053; TREX 11263; TREX 11264.
[32] Deposition Testimony of James Wellings at 44-45; 54 and 95; Joint Industry Program for Floating Vessel Blowout Control, Final Report, DEA-63 (1991); TREX 10166; TREX 8886.
[33] TREX 6299.
[34] Noynaert, "Modeling Ultra-Deepwater Blowouts and Dynamic Kills and the Resulting Blowout Control Best Practices Recommendations," SPE/IADC 92626 (2005).
[35] DEA – 63 (1991)
[36] TREX 10879; TREX 9787
[37] TREX 3918.
[38] TREX 10514
[39] DEA-63 (1991) at 7.9; TREX 10514

For the BOP-on-BOP solution, TO's DISCOVERER ENTERPRISE's BOP and its CS were available. For a Capping Stack solution, equipment and controls would have to be specified, sourced, assembled and tested.[40]

Meanwhile, work continued on the Capping Stack solution with a bottom connector being comprised of Cameron and TO owned equipment. The Capping Stack options included a 2-Ram or 3-Ram Capping Stack.

Before a BOP-on-BOP or Capping Stack solution could be utilized, a Transition Piping Spool was needed which would adapt to the flange atop the Macondo BOP's Flex Joint. [41]

In any source control situation:

> *"...[i]t is a fairly obvious observation that a blowout should be controlled with the optimum approach."*[42]

Determining an optimum approach required the consideration of the probabilities of success for a procedure, the terminal nature of the technique, i.e., whether such a technique could eliminate other options and the risks of the technique.[43] In response to its blowout, BP failed in selecting the procedure most suited to stop it in accordance with the above stated principles. BP's failure led directly to an increase in the amount of time that Macondo was allowed to uncontrollably flow into the GoM.

In comparing these two (2) procedures, it was necessary to understand both the inherent risks involved with these procedures and the probability of success. As set out below, once all variables are considered, it becomes clear that BP should have elected to implement the BOP-on-BOP solution.

Certain people within BP believed that the BOP-on-BOP solution was BP's *"...best shot"*[44] to contain Macondo. In addition, WWCI, TO and Cameron all believed that that BOP-on-BOP solution was the best procedure.[45]

WWCI constituted one of the blowout specialists brought in by BP to assist with the response in accordance with Section 6(c) of **BP's Gulf of Mexico Regional Oil Spill Response Plan**.[46] BP said that it is not a well control company yet it

[40] Deposition Testimony of James Wellings, 137:17-24.
[41] *Id, 42:1-6.*
[42] DEA-63 (1991)
[43] Id.
[44] TREX 4405.
[45] TREX 3922; TREX 10514; TREX 10884
[46] TREX 769

refused to defer to the well control specialists it hired regarding the secondary intervention technique to be deployed.[47]

The DISCOVERER ENTERPRISE was *"...in a position early on"* to install the BOP-on-BOP solution.[48] However, BP made the decision to attempt its Top Kill first.[49]

BP had already concluded that the BOP-on-BOP solution was both safe and feasible.[50] This strategy was also the quickest because the equipment was already on-site and required minimal modification.[51]

In addition, any concerns about the well's integrity would have been minimized because this BOP could be configured to vent hydrocarbons back out into the GoM if certain problems arose.[52] The strategy would also have improved the likelihood of a successful Top Kill procedure if the well was not shut-in right away.[53] BP knew that this was an advantage.[54]

Despite the advantages of the BOP-on-BOP solution, BP failed to give proper priority to preparing this procedure for implementation. TO's DISCOVERER ENTERPRISE was the vessel originally selected for the deployment and installation of the its BOP on the DEEPWATER HORIZON's BOP. Its BOP had been modified and prepared for use.

At the point when this BOP was *"...ready to go,"* BP considered making a switch and use TO's DEVELOPMENT DRILLER II's ("DDII") BOP.[55] On May 10, 2010, BP switched from the DISCOVERER ENTERPRISE's BOP to the DDII's BOP for its BOP-on-BOP solution.[56] BP re-deployed the DISCOVERER ENTERPRISE into a containment role. Thus, the BOP-on-BOP effort was delayed even further.[57]

After the DISCOVERER ENTERPRISE was switched to containment, its BOP was almost ready to be deployed such that it could shut-in Macondo.[58] BP had been in a position in early May, 2010 as this environmental emergency continued to

[47] Deposition Testimony of James Rohloff at 33-34
[48] TREX 8542
[49] Id.; TREX 10516; TREX 10675
[50] TREX. 10505.
[51] McWhorter Dep. at 473:21-474:6.
[52] TREX 10528; Turlak Dep. at 532:22-533:7.
[53] TREX 10543.
[54] TREX 10542; Holt Dep. at 619:16-25.
[55] TREX 10894
[56] *Id.*
[57] Deposition Testimony of Charles Holt at 416:24-417:12.
[58] Deposition Testimony of Robert Turlak, Nov. 6-7, 2012 at 360:23-361:8, 367:4-367:15; Deposition Testimony of Geoff Boughton, Jul. 20-21, 2011 at 79:1-13.

deploy a BOP-on-BOP solution yet, a decision was made to attempt the Top Kill first."[59]

The Top Kill suddenly became BP's preferred option[60] because it was BP's *"...first available thing"* to try.[61] The Top Kill was prioritized before the BOP-on-BOP solution against WWCI's advice.[62] The Top Kill[63] was a complex procedure developed to try to control the flowing sources either through a Junk Shot or a Momentum Kill.[64] This procedure involved pumping heavy and viscous drilling fluids and other materials through the BOP's Choke and Kill lines to stop the Well's uncontrolled flow.

The purpose of the Junk Shot was to establish restrictions in the flow and allow for a decrease in pressure in order to be able to kill this Well. Junk shots are typically designed to seal flanges, BOPs, valves or other equipment that are leaking. Different materials such as shredded rubber, nut hull, ball sealers and golf balls, are injected into the flow path. However, if the Junk Shot was successful, it would result in a potentially high shut-in pressure with the potential for casing failure[65] if these excessive pressures could not be relieved and/or vented.

The first review of the Top Kill procedure was prophetic:

> *"...the option of installing the DDII stack on top of the Horizon stack should be prioritized above the Q4000 operation [Top Kill] for executing the kill operation."*[66]

BP did not heed its own warning and proceeded forward with this option. The Top Kill was characterized as a *"High Risk"* and *"Low Probability of Success"* procedure.[67]

Risks associated with BP's Top Kill procedure were severe and potentially terminal to the Relief Well effort. To start, there was a risk of injury or death to the

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[59] TREX 08542; *see also* TREX 5385 (showing a timeline for attaching the Enterprise BOP and shutting the well by May 11, 2010).
[60] TREX 10516; TREX 10675
[61] TREX 10611
[62] Id.
[63] A Top Kill is an attempt to kill the well by pumping a predetermined weight of drilling mud down a pipe from the surface through a manifold and the choke and kill lines into the wellbore. The weight of the drilling mud is heavier than the formation pressure allowing the weight of the mud to push the formation fluids back down and into the formation.
[64] Deposition Testimony of David Barnett, December 14, 2012, 29:10-14, A Momentum Kill *"is done from the top of the well and essentially, it has to do with pumping the fluid fast enough to create enough friction at the top of the hole to force the reservoir fluid back into the reservoir."*, 31:23-25 *"The Momentum Kill is very rare- it doesn't have a very high percentage of success."*
[65] TREX 9135
[66] TREX 8541
[67] TREX 10509

individuals working with the high-pressure equipment necessary to implement the procedure. Beyond personal safety, the Top Kill included the risks of bursting the rupture disks leading to broach and impacting the relief well effort. The drilling of a Relief Well was BP's only known and tested technique for controlling the uncontrolled flow from their Well. In addition to these risks, a Junk Shot carried additional risks of creating pressure barriers and/or traps within the BOP and leading to a failure of well integrity and blocking access through the Choke and Kill lines of the Well's BOP. These risks are detailed in depth in multiple reports, memoranda and emails listed in Appendix B.

BP ignored these facts. In exchange for these risks, BP recommended and implemented a procedure which had little or no probability of success. BP obtained approval of this procedure by failing to disclose material information.

While BP told Government officials that the Top Kill would succeed, BP already knew that its chances of success were low and/or virtually nonexistent. BP's Mr. Kent Wells told Secretary Chu that the Top Kill was a "slam dunk."[68] BP's CEO Tony Hayward publicly stated on or about May 24th that the Top Kill had a 60-70% chance of success.[69] BP's public statements regarding the probability of success of the Top Kill were untrue.[70]

On or about May 6th, a **BP Presentation** giving a summary of the Junk Shot Protocol stated that:

"Junk shots are often not successful..."[71]

WWCI also considered the technique to have a low chance of success which was why it was only very rarely used.[72]

The success of a Top Kill was dependent and susceptible to Well flow rates.[73] BP knew that if its Well's flow rate was greater than 15,000 barrels of oil per day ("bopd"), that its Momentum Kill would not succeed.[74] As discussed, BP knew the flow rate exceeded 5,000 bopd but was also more than the 15,000 bopd limit for

68 Deposition of Secretary Steven Chu, Jan. 24, 2013 at 308:9-308:16.
69 *See* TREX 10532.
70 Robert Markham ("Mark") Patteson, the Top Kill lead, was unaware of any probability analysis being conducted for the Top Kill and was unaware of any information or data that would support a 60-70% probability of success. Patteson Deposition Testimony at 263-264.
71 TREX 10506.
72 Deposition Testimony. of David Barnett, Dec. 14, 2012 at 31:17-25; 105:13-106:8; 106:25-107:5; 180:5-180:22
73 Deposition Testimony of Dr. Marcia McNutt, Oct. 24-25, 2012 at 449:19-450:4.
74 TREX 8537; TREX 9132; Deposition of Ole Rygg, Oct. 3, 2012 at 205:14-206:2; Holt Dep. at 197:17-198:14 ("anything above 15,000 barrels a day in the modeling that had been done, said that – that it was going to be very difficult, if not impossible, to use the dynamic kill to kill this well.").

its Momentum Kill. For example, Halliburton informed BP that it believed the Macondo was flowing in excess of 30,000 bopd.[75]

The impact of the flow rate was summarized by Mr. Frank Vargo, of Halliburton:

> *"With the knowledge that the top kill could not have worked based on the 15,000 barrel per day limitation, then we shouldn't have moved forward with the top kill because it was going to put everybody at risk and the well at risk. Not – I mean, I don't – we're ending up here. But I don't think anybody really understands how dangerous what we were about to do was."*
>
> *"I mean, we have high-pressure equipment out there, people working around 15,000 psi equipment. If something came apart, you would have killed people. If you looked at the pictures of the boat, I mean, we had people – equipment on top of equipment. It was a dangerous, dangerous operation. And if they had knowledge that that was the case, we shouldn't have moved forward."*[76]

BP told Dr. Marcia McNutt, the Director of the United States Geological Service and the Flow Rate Technical Group that the success of the Top Kill option was not dependent on the flow rate.[77] BP did not inform Dr. McNutt about the 15,000 bopd limit, which would have been helpful in evaluating the success or failure of the Top Kill.[78]

Two (2) Government officials had to sign off on the Top Kill method before BP could proceed with it: Federal On-Scene Coordinator Admiral Landry and the MMS Gulf of Director Mr. Lars Herbst.[79] Neither were informed of the 15,000 bopd limit. Later, Mr. Herbst testified that this information would have been "very helpful".[80]

BP misrepresented the flow rate of the well to Landry and Herbst, withholding its internal analysis, estimates and models. Admiral Landry expected BP to keep her apprised of all of its flow rate modeling and estimates, but BP had not.[81]

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[75] Deposition testimony of Halliburton 30(b)(6) witness Frank Vargo at 92-93
[76] Id. At 316 – 317.
[77] McNutt Dep. at 412:17-413:11.
[78] McNutt Dep. at 414:178-415:8.
[79] TREX 9353.
[80] Herbst Dep. at 441:17-442:13.
[81] *See* Landry Dep at 560:26-24, 582:1-19, 583:24-584:3, 584:23-585:13, 600:13-19, 605:1-21, 618:17-619:4.

BP also provided incomplete and misleading flow rate data to Secretary of Energy Steven Chu.[82] Rather than share with Secretary Chu the flow rate estimates which exceeded 15,000 bopd, BP told him that:

> *"...they wanted to proceed with the top kill, that they were confident that it was going to work, . . . and that they . . . had the capability of marshaling counter flows that would overwhelm what was coming up."*[83]

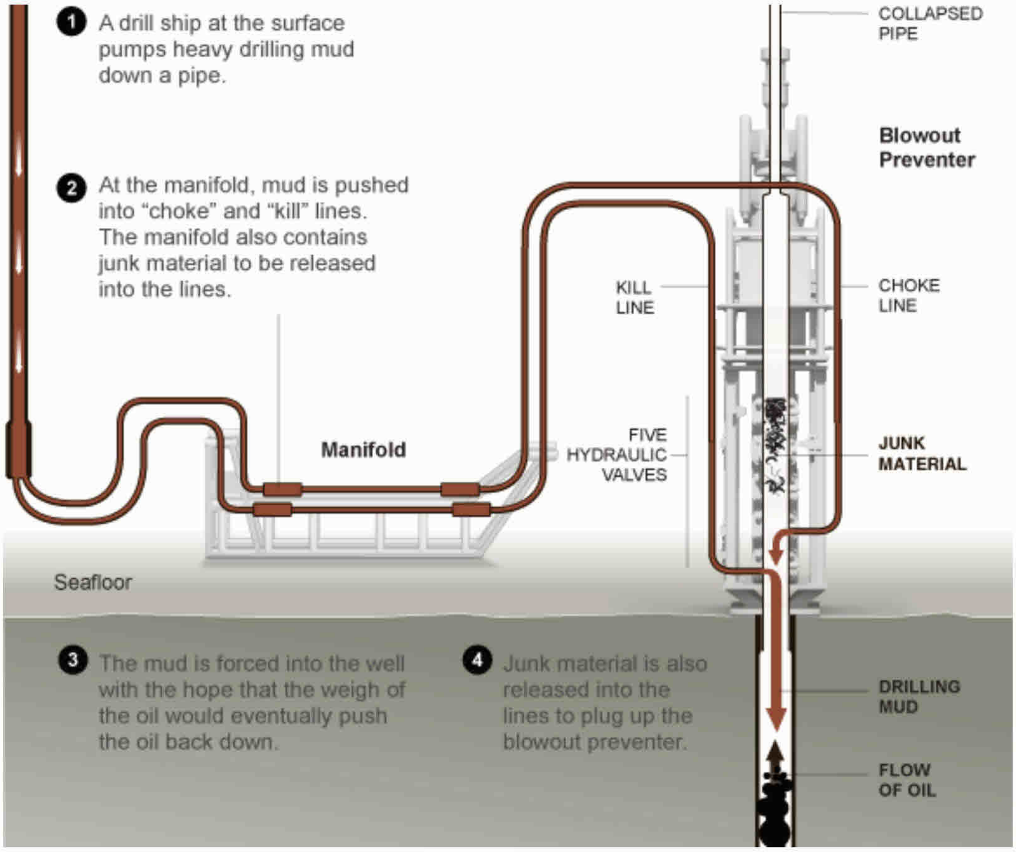
While failing to disclose that the Momentum Kill would not be successful if the well was flowing more than 15,000 bopd, BP was actively withholding or misrepresenting to everyone what it knew regarding the actual flow rate of their Well. While publicly stating the well was flowing at only 5,000 bopd, BP knew otherwise. According to BP's Criminal Plea Agreement, this knowledge formed the basis of BP's recent felony plea for Obstruction of Congress.[84]

BP possessed internal flow rate calculations well in excess of both the 5,000 bopd public statements and the 15,000 bopd limit for the Momentum Kill to be successful.[85] In light of this information, BP was fully aware that its Top Kill would not be successful. BP withheld this information from federal officials who unknowingly approved a procedure that BP knew could not work.

BP's Top Kill began on the afternoon of May 26 from the Q4000. Water Based Mud ("WBM") at a weight of 16.4 pounds per gallon ("ppg") was pumped into the Well at a rate of 35-60 barrels per minute ("bpm") through the BOP's choke and kill lines. Three (3) attempts were made to pump mud at rates of up to 80 bpm or more than 115,000 barrels/day.

Refer to the diagram on the following page.

[82] Chu Dep. at 188:9-189:6, 213:7-218:18.
[83] *Id.* at 206:2-13.
[84] TREX 11422
[85] TREX 6110; TREX 8656; TREX 9274; TREX 9292; TREX 2418; TREX 9257; TREX 9267; TREX 9266; TREX 8866; TREX 8865; TREX 9620; TREX 8894; TREX 8942; TREX 5063; TREX 9843; TREX 9629; TREX 3910; TREX 8657; TREX 3063; TREX 9274; TREX 9292



Top Kill and Junk Shot Flow Diagram
Source: NY Times

Both the Top Kill and the Junk Shot efforts failed to plug the Well and stop the flow. [86]

2. *BP withheld data from the post-Top Kill analysis from the U.S. Government and misrepresented the reason for the failure of the Top Kill.*

Even before the Top Kill project was halted, BP was moving to stop the spread of information regarding why it failed. On May 27, 2010, Mr. Rupen Doshi, a BP employee sent an email stating:

> *"...just want to make it clear that **NO ONE** is to get the data files from the Top Kill method that is being pumped from yesterday or today except for Paul Tooms' group. This order comes directly from Bill Kirton and Charles Holt."*[87]

[86] National Commission on BP Deepwater Horizon oil Spill and Offshore Drilling, *Stopping the Spill: The Five-Month Effort to kill the Macondo Well, Updated January 11, 2011,* TREX 2291, pg. 17
[87] Email String from Paul Tooms, Doshi Rupen, Mark Mazzella, TREX 9164.

That night, Mr. Paul Tooms emailed BP employees Mr. Doshi, Mr. Jace Larrison, and Mr. Mark Mazzella.

> *"The purpose of the note was meant to put a limit on the people outside the circle of trust getting the data."*[88]

BP prevented Mr. Herbst and Rear Admiral Kevin Cook from entering and participating in a meeting to discuss the Top Kill's failure.[89]

BP asserted that the failure of the Top Kill was due to the presence of "rupture disks"[90] in the 16" diameter casing/liner. BP presented that its analysis of the Top Kill data showed that the mud being pumped down the backside of the well had gone out through the collapsed rupture disks or the shoe of the casing and into the rock formation, rather than remaining within the well and pushing the hydrocarbons back into the reservoir as intended.[91]

BP's own source control contractor, WWCI, concluded that the Top Kill did not fail due to ruptured disks but because the flow path was too large[92] and subsequently informed BP of this.[93] BP employee Mr. Kurt Mix indicated that the Top Kill was not succeeding because the flow rate was too high and the orifice was too large.[94] This conclusion was not shared by BP with the U.S. Government.

On May 29, 2010, BP contractor Mr. Thomas Selbekk concluded from pressure data gathered during the Top Kill that no mud entered the wellbore.[95] As a result, the pumped mud could not have reached or flowed through the rupture disks as claimed

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[88] *Id.*
[89] Deposition Testimony of Lars Herbst , 487:3-490:4, 239:22-244:3.
[90] Rupture Disks are engineered to rupture or burst outward if the pressure between the 16" casing and the production casing reached 7500 pounds per square inch ("psi") or if the outside of the 16" casing reached 1600 psi, the rupture disks would collapse inward. Once ruptured, the disks create small holes in the 16" casing to bleed off pressure into the surrounding rock formation.
[91] Deposition Testimony of Lars Herbst, October 10, 2010,160:7-17; TREX 9084; TREX 9163.
[92] Deposition Testimony of David Barnett, 11:11-122:2, 237:7-20; TREX 10534; TREX 10622.
[93] Deposition Testimony of David Barnett, 239:8-240:23, 240:24-242:24; Project Memo from David Barnett to Mark Mazzella, Mark Patteson, May 31, 2010, TREX 10622 "*...Several attempts were made to subdue the well...it ultimately became obvious that the top kill method was ineffective..Unless some means can be devised to decrease the area of the flow path...it is considered extremely unlikely that further top kill operations will be successful in controlling the well.*"
[94] TREX 9160, "*too much flowrate – over 15000 and to large an orifice...*"
[95] TREX 9265.

Again, this information was not shared with U.S. Government's decision makers.[96] Mr. Selbekk's conclusion made BP's explanation implausible and the explanation that the flow rate was too high and orifice too large even more plausible.

Additionally, on May 31, 2010, BP contractor Mr. Morten Emilson concluded that the uncontrolled hydrocarbon flow path was up inside the inner-most casing, not the annulus.[97] If this was true, then the pumped Top Kill mud and hydrocarbons could not have escaped through rupture disks which were located in the outer 16" OD casing. BP had not disclosed Mr. Emilson's report to the U.S. Government until late May or early June, 2010.[98]

BP's theory that the rupture disks in the 16" OD casing burst removed the BOP-on-BOP option from being the next step attempted.[99] However, if any earlier attempts at EDS, AMF, Autoshear, and/or ROV intervention had been successful, the Well would have been shut-in and subsequently subjected to the same internal pressures as would be experienced with a Capping Stack or BOP-on-BOP solution in mid-May.

A BOP-on-BOP or a Capping Stack solution would have allowed for the control of pressure with the ability to bleed pressure off through the Choke and Kill Lines. Further, had the Junk Shot successfully sealed the Well and the flow ceased, there would have been no ability to (a) control the Well's internal pressure or (b) unseal it.

BP's lack of candor regarding the failure of the Top Kill directly led to the removal of the BOP-on-BOP solution and created a heightened concern regarding its Well's integrity. BP's misrepresentations removed what was considered to be BP's best option and/or solution for shutting-in and sealing this Well. BP's misrepresentations directly caused a delay in the installation of a 3-Ram Capping Stack solution. Had BP been open and honest with themselves, the U.S. Government, their Consultants and Service Providers and the General Public, their Well could have been shut-in and sealed much sooner.

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[96] TREX 9265; Deposition Testimony of Ole Rygg, 257:13-261:18; Deposition Testimony of Trevor Hill, 518:22-519:1; Deposition Testimony of Lars Herbst, 505:24-506:22; Deposition Testimony of Thomas Hunter at 614:22-61:21; TREX 9084; TREX 9163.

[97] TREX 7270

[98] Deposition Testimony of Lars Herbst, 508:25-509:15, 511:18-512:2; Deposition Testimony of Douglas Suttles, May 19-20, 2011, 824:20-825:10; TREX 9084; TREX 9163

[99] TREX 9084; TREX 9163; Deposition Testimony of Hunter, 606:15-607:16.

SUMMARY OF OPINIONS & CONCLUSIONS:

The below is a summary of the opinions I offered above. Each of the opinions and conclusions below are supported by the conclusions listed with the opinion as well as the discussion and findings above.

OPINION 1: PRIOR TO APRIL 20, 2010, BP [redacted] WERE AWARE THAT DEEPWATER BLOWOUTS COULD OCCUR AND THE CONSEQUENCES COULD BE DISASTROUS WITH THE POSSIBILITY OF DEATH AND SEVERE ENVIRONMENTAL DAMAGES.

1. BP [redacted] knew that blowouts have occurred on both land and subsea and continued to occur at a constant incident rate. While a blowout of this magnitude was a low probability event based on historical drilling in the GoM, it was not an unforeseeable event and BP had identified that risk.[100]
   a. A Study by Skalle and Podio in 1996 reported that deepwater wells accounted for only 2% of all wells drilled. Yet, they accounted for 8% of subsea blowouts.

   "No blowout has yet occurred in ultra-deep water (water depths of 5000ft or greater), but statistics show it is likely to happen. Are we ready to handle it?" [101]

   b. A 2001 **SINTEF Deepwater Study** reported that a total of 117 BOP failures and 48 well kicks ("Kick" or "Kicks") were recorded in the 83 wells observed between 1997 and 1998. Many Kicks occurred with a narrow margin between the Well's pore pressure in the formation and the formation's fracture gradient.[102] Macondo was a high pressure/high temperature exploratory well in the GoM with a narrow margin, as described;
   c. Prior to Macondo there have been 44 notable blowout events including the Ixtoc well in Mexican waters of the GoM which took 6 months to shut-in and seal; [103]
   d. AN MMS Study in 2007 concluded that 39 blowouts occurred between 1992 and 2006 during drilling operations in the Outer Continental Shelf ("OCS").[104] And;

[100] Deposition Testimony of Charles Holt, November 28, 2012, 46:1-9; Deposition Testimony of James Rohloff, October 17, 2012, 52:22-23 *"A deepwater blowout would have been a possible source control event, yes."*; Deposition Testimony of Richard Harland, January 10, 2013, 245:5-13 *"Q. If well control fails, a blowout can occur, correct? A. A possibility."*

[101] SPE 53974, Skalle, P., Trondheim, J.H. and Podio A.L.: *Killing Methods and Consequences of 1120 Gulf Coast Blowouts During 1960-1996;* 2003 SPE/IADC Drilling Conference, SPE/IADC 79880 *Well control Procedures for Dual Gradient Drilling as Compared to Conventional Riser Drilling,* February 21, 2003, TREX 6299.

[102] Deepwater Kicks and BOP Performance, SINTEF Industrial management, Report No. STF38 A01419, July 24, 2001.

[103] William Campbell, *Blowouts not Such Rare Events,* The Maritime Advocate Online, Issue 444, July 12, 2010.

e. Between 2008 and 2009, TO reported that one (1) in seven (7) exploration wells experienced a Kick, of which there were six (6) riser unloading events.[105]

[redacted]

OPINION 2: BP [redacted] WERE AWARE THAT BOPS COULD NOT SOLELY BE RELIED UPON TO SEAL THE UNCONTROLLED FLOW FROM A WELL PRIOR TO APRIL 20, 2010. FURTHER, THAT ROVS WOULD NOT BE SUCCESSFUL IN CLOSING A BOP ON AN ACTIVELY FLOWING WELL.

1. During a well control event, the ultimate goal is to shut-in and seal the well as quickly as possible; [107]
2. A BOP is a pressure vessel. It is a mechanical assembly of valves which have been known to fail. [108] For deepwater drilling operations, reasonable contingencies must be developed for any mechanical failures [109] especially on a safety critical piece of equipment such as a BOP.
   a. A **List of Blowout Incidents** in the GoM prior to 2001 showed there to be 24 blowouts referenced, many of which experienced a Blind Ram's failure to close and seal in the Well.[110]

[redacted]

[104] David Izo, et al, *Absence of Fatalities in Blowouts Encouraging in MMS Study of OCS Incidents 1992-2006,* Well Control, Drilling Contractor, July-August 2007.
[105] Transocean Annual Report – Well Control Events & Statistics Divisional Summaries, 2009, TREX 4255.
[106] IADC Deepwater Well Control Guidelines, First Edition, October 1998, TREX 7353, 4.2.1 "Blowout Contingency Planning"; Email from Richard Eaton to Doug Suttles, et al, Subject: OpCo Risk Review, October 9, 2009, TREX 2914; PCII Final Report, Oil Spill Containment, Remote Sensing and Tracking for Deepwater Blowouts: Status of Existing and Emerging Technologies, August 12, 1999, TREX 9552; 2005 SPE-IADC 92626, Modeling Ultra-Deepwater Blowouts and Dynamic Kills and the Resulting Blowout Control Best Practice Recommendations, 2005; Development and Assessment of Electronic Manual for Well Control and Blowout Containment, A Thesis by Odd Eirik Grottheim, August 2005.
[107] Transocean Well Control Manual, TREX 596 *"Early recognition of the warning signs and rapid shut-in are the key to effective well control…When a well kicks, it should be shut-in within the shortest possible time."*
[108] Deposition Testimony of Steve Hand, 47:10-13, Deposition Testimony of Robert Turlak, 147:9-20.
[109] Deposition Testimony of David McWhorter 180:2-3, 21-22.
[110] Date, Locations, and Description of Incidents Where Blind-Shear Rams Either Helped control or May have Helped Control a Blowout, TREX 6146.

[redacted]

4. [redacted] BP were [redacted] aware that ROV intervention was not a viable secondary intervention option.
   a. In 2002, the **IADC Deepwater Well Control Guidelines** recognized that the ROV has limited capabilities and with the technological changes in the deepwater arenas, ROVs have not made significant advances to aid in floating vessel blowout control; [112]
   b. Industry studies warned that in a blowout situation, high flow rates would accelerate the erosion process and decrease the likelihood of the ROV to be able to close in the well. The amount of pressure required during increased flow rates, the ability to work in the mud plume and the limited pumping capacity would not make the ROV a viable secondary intervention measure in a blowout scenario; [113]
   c. In a hypothetical posed by Mr. Michael Byrd, a BP employee, on November 14, 2001, Mr. Byrd asked what would happen if the DEEPWATER HORIZON were to drive off-of a Well it was drilling, leaving an uncontrolled flowing Well behind? The answer he received was that trying to close the BOP's one (1) and only Blind Shear Ram ("BSR") BSR would not work to shut-it-in and seal it because the BSR would get "washed-out" [114] and;

[redacted]

5. BP [redacted] failed to consider the consequences of such BOP failures at progressively different operational levels.

[redacted]

[112] 2002 IADC Deepwater Well Control Guidelines, TREX 7353, 4.3.10.
[113] West Engineering Services, Inc. Evaluation of Secondary Intervention Methods in Well Control for US MMS, March 2003, TREX 1166, pg. 27, 4.3.7 Discussion; Deposition Testimony of Pat Campbell, July 13, 2011, pg. 163-167.
[114] Email from Michael Byrd to Curtis Jackson, et al, 11/14/2001, Subject: PREP Exercise, TREX 4423.

[redacted]

OPINION 3: BP [redacted] [redacted] MANAGEMENT WERE AWARE THAT PROVEN CAPPING STACK TECHNOLOGIES EXISTED AND COULD BE DESIGNED AND BUILT TO RESPOND TO AN UNCONTROLLED BLOWOUT EMERGENCY PRIOR TO APRIL 20, 2010. ALSO, BP [redacted] [redacted] KNEW THAT THIS EQUIPMENT MAY NOT BE READILY AVAILABLE IMMEDIATELY AFTER AN EMERGENCY OCCURRED. BP [redacted] [redacted] HAD NOT PLANNED FOR, NOR HAD [redacted] TAKEN ANY STEPS, TO PROVIDE A CAPPING STACK SOLUTION FOR MACAONDO.

1. Equipment that was designed, manufactured and configured by Cameron had been successfully used by others as part of Capping Stack solutions used both onshore and offshore. [116] Cameron BOPs have been used for Capping Stack solutions as early as 1980's and were used extensively during the Kuwait fires; [117]
2. BP [redacted] knew Capping Stack solutions were not new technology and the industry had equipment available for either a BOP-on-BOP or Capping Stack solution; [118]

[redacted]

4. BP was aware of the possible use of Capping Stacks in a deepwater environment. In BP's **GoM Deepwater SPU Well Control Response Guide**, Capping Stack solutions are specifically mentioned as a Level 3: Phase 2 –Well Control Response; [120]
5. Deepwater Capping Stack solutions were technologically feasible before Macondo was spudded. Therefore, BP [redacted] should have had a suitable Capping Stack solution, including a back-up designed, assembled, built and tested prior to this incident. Had BP [redacted] done so, Macondo could have been shut-in and sealed-off much earlier;
6. There was no technological reason why BP could not have designed and/or obtained other subsea containment equipment and well control procedures for Macondo. For example, BP [redacted] knew or should have known that if a well control event such as this were to occur, ROV intervention would be unreliable and/or potentially incapable of positively energizing and closing any of the Ram-Type Preventers in the subsea BOP stack such that Macondo could be reliably shut-in and sealed;

116 *Id, 189:19-24.*
117 *Id, 175:8-14, 23-25, 176:5-13, 177:9-19.*
118 Deposition Testimony of Robert Turlak, November 6, 2012, 187:3-7, 194:1:16; Email from Jack Sheen to James Wellings, Subject: Exxon Mobil CEO says risk – not chances of success-dictated spill response, September 23, 2010, TREX 11227, *"the industry was relying on "things we already had and knew hot do do." Tillerson said. "The pieces were there, but we had to assemble them in the right way to respond."*
[redacted]
120 BP GoM Deepwater SPU Well Control Response Guide, January 2010, TREX 2386.

7. BP knew that there was a need for more reliable and responsive equipment with regard to total well control for their Deepwater Drilling operations. BP management's own guidelines required that all risks associated with the drilling of a specific well be identified, evaluated, addressed and mitigated. Even without written guidelines, a prudent Operator should, prior to commencing a drilling operation, identify, assess, and manage risks of the operation, including the possibility of an uncontrolled blowout. [121]

[redacted]

OPINION 5: BP MANAGEMENT KNOWINGLY MISREPRESENTED THE REASONS WHY THE TOP KILL FAILED WHICH LED TO THE DELAY OF THE USE OF A CAPPING STACK SOLUTION.

1. BP misrepresented the reason for the failure of their Top Kill;
2. BP knew the Top Kill would not be successful if the well was flowing at more than 15,000 bopd;
3. BP's failed to disclose material information regarding the existence of data, estimates, and calculations showing a higher flow rate than that publicly

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[121] 2008 International Oil Spill Conference, Assessment of Oil Spill Response Capabilities: A Proposed International Guide for Oil Spill Response Planning and Readiness Assessment, TREX 11400.
[122] May 11 Senate Hearings, Mr. McKay Testimony, TREX 7346, pg. 53.
[123] Notes from NRT Call Saturday April 24, 2010 at 1000, TREX 8886.
[124] Email from Tony Hayward, Subject: Update: Gulf of Mexico Rig Incident (25 April 2010), April 25, 2010, TREX 10166.
[125] National Commission on the BP Deepwater Horizon Oil spill and Offshore Drilling: *"Stopping the Spill: The five-Month Effort to Kill the Macondo Well"*, Updated January 11, 2011, TREX 2291, p. 5.

announced. Yet, BP continued to represent that 5,000 bopd was its best estimate of the flow rate;

4. BP explained the only possible and plausible reason for the failure of the Top Kill was that the mud flowed through burst rupture disks in the 16" OD Casing and that further intervention efforts would lead to a subsea blowout. And;
5. Because of their misguided and baseless justification, BP removed the BOP-on-BOP solution and the designing, building and testing of a 3-Ram Capping Stack solution was delayed.[126]

OPINION 6: BP MANAGEMENT RECOMMENDED PROCEDURES THAT BP KNEW HAD GREATER RISK WITH LESS CHANCE OF SUCCESS.

1. In the most dangerous of drilling environments, BP's only contingency plan for a blowout was to drill a Relief Well; [127]
2. Many of the containment methods BP attempted were improvised and untested and deemed to have a high risk of success; [128]
3. An optimum approach for Kill technique selection should be the probability that the technique will work under the blowout conditions being experienced. Consideration should be given to all Kill options on an equal basis prior to making the final decision; [129]
4. WWCI, Cameron, Anadarko and Transocean all believed the best source control option for the Macondo well was the BOP-on-BOP and/or Capping Stack solution; [130]

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[126] Deposition Testimony of Charles Holt, 209:2-209:7, 390:6-390:17; Deposition of Admiral Mary Landry, 635:18-636:5; TREX 10686; Deposition Testimony of Lars Herbst, 495:9-496-:3, TREX 11231, TREX 11232.

[127] Deposition Testimony of James Rohloff, October 17, 2012, 48:2-17.

[128] Letter from Pat Campbell to Mark Patteson, May 12, 2010, TREX 3922, *"…it's my understanding that a number of BP initiatives are being considered for "pro-active" deployment and implementation. It's my personal opinion that the risk associated with most of the initiatives is too high…";* Email from Stuart Nelson to Don King, Ref: BP Horizon – BOP Pressure Relief Manifold, May 30, 2010, TREX 10514, *"Everything they have done so far is an experiment.";* Summary points from the Kill the Well on Paper Discussion, May 18, 2010, TREX 8553; Email from Ole B. Rygg to Kurt Mix, Subject: Top kill – 5000 and 15000 bopd, May 16, 2010, TREX 8537; Planning Procedure for Junk shot, Bullhead, and Momentum Top Kills, Version #10, May 4, 2010, TREX 11412

[129] DEA 63 Report, 1991, *"situations have occurred in which one approach was followed against recommendations of other groups for alternative approaches that had significantly more technical merit.."*

[130] Email from Stuart Nelson to Don King, Ref: BP Horizon – BOP Pressure Relief Manifold, May 30, 2010, TREX 10514, *"If it was up to me I would have done that [BOP on BOP solution} in the very beginning. Everything they have done so far is an experiment. Releasing the LMRP, cutting the drill pipe and installing a new BOP is the way it was designed to work in the first place.";* Letter from Pat Campbell to Mark Patterson, May 12, 2010, TREX 3922; Email from Nancy Seiler to Jim Hackett, Subject: Comments, June 3, 2010, *"Drilling 101 would have been to immediately cut the Riser and pull the LMRP.",* ANA-MDL000230538-230539

5. A Capping Stack and BOP-on-BOP solution were both source control options shortly after the rig sunk.[131] Both stacks were designed, manufactured, and tested in parallel with the other solutions being attempted during the early part of the blowout, i.e. the cofferdam, the Junk Shot, the Top Kill and various collection devices; [132]
6. A plan for a Capping Stack solution began to be developed on April 27, 2010; 7 days after the blowout;
7. The Capping Stack solution incorporated many off-the-shelf components into its design. After the actual Capping Stack was built, it underwent lengthy surface-testing installation procedures on simulated Macondo wellhead equipment which could have been mitigated had a Capping Stack solution been identified and been made available well in advance of this event;
8. BP recommended and proceeded with the Top Kill and Junk Shot procedures in an attempt to shut-in the Macondo Well even though BP knew that the Top Kill was not viable if the Well was flowing in excess of 15,000 bopd; [133]
9. BP prioritized the Top Kill and Junk Shot procedures over the BOP-on-BOP solution to shut-in the Well knowing that the BOP-on-BOP solution was the best available technology and most effective solution to shut-in the Well;
10. BP misrepresented the reason the Top Kill failed as being the Top Kill pumped into the Well had exited the through the burst rupture disks into the surrounding formation while knowing the reason for failure was attributable to the 15,000 bopd flow rate the well was experiencing. [134]

CONCLUSION:

These are my opinions within a reasonable degree of probability, based upon my education, training, experience and my review of the materials referenced in Appendix A.

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[131] National Commission on the BP Deepwater Horizon Oil spill and Offshore Drilling: *"Stopping the Spill: The five-Month Effort to Kill the Macondo Well"*, Updated January 11, 2011, TREX 2291, p. 26.

[132] Email String from Pat Campbell to David Moody, et al, Subject: Schedule – DDII BOP on Horizon BOP 5-17, Capping Stack Support, May 17, 2010, TREX 10611; Email String from Eddy Redd, to Steve Hand, et al, Subject: Priority for Completion of the BOP Work on the DDII, May 15, 2010, TREX 10879.

[133] Email from Ole B. Rygg to Kurt Mix, Subject: Top kill – 5000 and 15000 bopd, May 16, 2010, TREX 8537; Summary points from the Kill the Well on Paper Discussion, May 18, 2010, TREX 8553; Email String from Curtt Ammerman to Guffe, Subject: Summary of Well Kill Meeting, May 18, 2010, TREX 9135, *"...we were shown today that if the flow rate is 15,000 bopd instead of 5,000 bpd, the modeling shows it is likely the well kill will not be successful."*

[134] TREX 11408, TREX 10531, Q4000 Operations Pump-in Diagnostics and Potential Top Kill Option Presentation (BP-HZN-2179MDL05016264), TREX 10534, 6-1-10 HESI email (HAL_0531154), TREX 9084, TREX 9160, TREX 9103, Email from Bill Kirton Re: MC252 Pressure Limitation.ppt (May 16, 2010)(BP-HZN-2179MDL07449737); TREX 5877, TREX 10543; BP Technical Note, Macondo 16" x 9/78" Annulus Pressure Integrity, May 17, 2010, TREX 5877

APPENDIX A

SOURCES AND INFORMATION CONSIDERED

In addition to the Consideration Materials attached with my Phase 1 Expert Report of August 26, 2011, I have reviewed the following documents listed in the attached Excel spreadsheet. It is possible that I may have briefly reviewed some documents not listed in this appendix. I have tried to list those things that I have considered as noted in my report.

In addition, I made five trips to the NASA Michoud facility and personally inspected the BOP and other components in connection with the Deepwater Horizon incident. I also inspected various components associated with the relief effort. During these visits I took photographs of the items I reviewed.

Also, since April 20, 2010 I have seen various new media reports, pictures, videos, and miscellaneous articles related to the incident.

A list of the materials I have reviewed and considered are provided in the form of an Excel spreadsheet.

APPENDIX B

GREGG S. PERKIN, P.E.
CURRICULUM VITAE AND OTHER ATTACHMENTS