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

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF LOUISIANA
MDL NO. 2179, SECTION J

JUDGE BARBIER; MAGISTRATE JUDGE SHUSHAN

Rebuttal Expert Report of Iain Adams

Submitted on behalf of BP Exploration & Production Inc.

June 2013

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TREX-011738R.003

PURPOSE OF REPORT; QUALIFICATIONS

My name is Iain Adams. BP Exploration and Production Company retained me to provide an expert opinion regarding BP's participation in the Unified Area Command's ("UAC") Response ("the Response") to the loss of well control at the MC 252 Well ("the Well") on April 20, 2010, and to review and consider reports filed by the Plaintiffs' Steering Committee ("PSC") as they related to those efforts. Subsequent to filing a report in response to the PSC reports on May 10, 2013, I was asked to review and consider reports filed by Transocean and Halliburton. Those reports were written by [redacted] Mr. Edward R. Ziegler, and [redacted] and John L. Wilson.

My qualifications and resume are included in the report that I filed on May 10, 2013. This report presents my opinion concerning the reports of Messrs. [redacted] Ziegler [redacted].

CONCLUSIONS

The reports prepared by Messrs. [redacted] Ziegler [redacted] and Wilson do not change the conclusions I reached in my May 10 report. It is my opinion that the engineering recommendations made by BP to the Unified Area Command were prudent and recognized the risks and benefits of each source control option and the availability of alternative options. In particular, I believe undertaking the risk-mitigated Top Kill procedure in May 2010 was a reasonable decision in light of its potential benefits and the availability of alternative source control methods at that time. When Top Kill was attempted, engineering work to ensure a safe and viable capping option was still underway. With the risk mitigation work for the capping options ongoing in May 2010, and given other challenges faced by BP and the Unified Area Command, neither the "BOP-on-BOP" option nor a capping stack was ready to deploy prior to the Top Kill operation.

DISCUSSION

1.0 THE BOP-ON-BOP OPTION AND THE CAPPING STACK OPTION WERE NOT READY TO DEPLOY IN MAY 2010 IN A MANNER THAT SUFFICIENTLY MITIGATED RISK

[redacted] Halliburton's Mr. Ziegler [redacted] claim that BP could have and should have capped the Macondo Well in May 2010 by either landing a second BOP on the *Deepwater Horizon*'s BOP ("BOP-on-BOP"), or a two-ram Capping Stack on the *Horizon* BOP.[1] Neither solution was ready to safely

[1] [redacted] Report of Edward Ziegler at 27 (May 1, 2013) ("Ziegler Report").

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deploy in May 2010.

The condition of the Macondo Well, and the Well's ability to maintain integrity if the Well were shut in by means of a second BOP or a capping stack, were unknown in May 2010. If the Well lost integrity, a shallow subsea broach would have presented significant risk to the environment and to the Response itself. To mitigate the risk presented by the capping options, the source control team at the Houston Incident Command Post ("ICP") needed to develop and validate a method of regulating pressure for the capping options.

The solutions to the risks presented by the capping options were not ready for deployment in May 2010. Given the identified risk of subsea broaching, in my opinion the correct solution was to be able to regulate pressure in a capping option, and without such an ability capping was not a viable option.

1.1 THE BOP STACKS TO BE USED FOR THE BOP-ON-BOP OPTION COULD NOT HAVE BEEN LANDED ON THE DEEPWATER HORIZON BOP IN MID-MAY

As explained below, the primary consideration for when a viable risk-mitigated BOP-on-BOP was available was the development of a subsea choke and vent system to manage pressure within the Well. [redacted]

Initial planning for the BOP-on-BOP option at the Houston ICP involved the potential use of the BOP from the *Discoverer Enterprise*. The *Enterprise* was also the only vessel in the Gulf of Mexico capable of collecting hydrocarbons from the Macondo Well.[2] Planning therefore shifted on May 11 to the use of the *Development Driller II* ("*DDII*") BOP as the capping BOP, as that vessel was preparing to join the Response.[3] At the time of the shift in planning on May 11, necessary work on the *Enterprise* BOP was still ongoing. A third-party inspection by West Engineering had identified necessary work to be completed on the *Enterprise* BOP stack that had not yet been completed on May 16, when the West representatives left to begin their inspection of the *DDII* BOP.[4]

The *DDII* BOP had previously undergone pressure testing and a third-party inspection by West Engineering in March 2010.[5] With such a recent inspection, only a few days of testing and maintenance of the BOP would reasonably be expected. However, during testing in May 2010, several leaks and other maintenance issues were found that required Transocean personnel to undertake repairs to the Transocean-owned and maintained *DDII* BOP.[6] This work took until May 29 to be

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[2] Deposition of Richard Lynch at 231.

[3] IIG013-066363.

[4] BP-HZN-2179MDL07807382.

[5] BP-HZN-2179MDL04371343.

[6] BP-HZN-2179MDL06026132.

completed.[7] Not until Transocean had its BOP ready could it have been deployed as part of a BOP-on-BOP solution. The scope of this work could not reasonably have been anticipated by BP or the Unified Area Command.

1.2 BOP-ON-BOP VENTING AND PRESSURE MANAGEMENT WAS NECESSARY TO MANAGE RISK

As part of the necessary and prudent work to identify and mitigate risks in developing capping solutions, the BOP-on-BOP solution called for the inclusion of a subsea choke connected to a vent manifold that would allow the venting of hydrocarbons.[8] The design, sourcing, installation, and testing of such a system is not an insignificant undertaking, and a Transocean engineer estimated on May 18 that a solution would take ten to fourteen days.[9] In my experience that is a reasonable, if optimistic, estimate. Inclusion of such a choke and a vent manifold was critical in two different respects.

First, inclusion of the choke was necessary to ensure the engineering team could control the shut in process and avoid potential problems in the Well. Some background is necessary to appreciate this first point. When a well is shut in with a blind shear ram, the well flow is rapidly stopped due to the short time (less than 45 seconds) used to close the ram. The rapid change in flow can produce a pressure surge in the well called the “water hammer” effect, which can expose the wellbore to higher pressures than it would otherwise have to withstand. The well will then be subject to the full shut in wellhead pressure. The nature of the rams is that they are either open or closed, there is no incremental step. After the incident on April 20, 2010, the condition of the wellbore at Macondo was unknown, and there was legitimate concern around how much pressure any source control activity could safely exert on the wellbore. The risk of exposing the Well to potentially unsafe pressures could not be ignored.

In contrast, a choke system allows what is called a “soft” shut in. Using a choke system, the well can be slowly shut in by incremental closure of the choke’s orifice. This incremental approach allows an engineer controlling the process to ensure that pressures increase slowly while he monitors those pressure increases. This avoids the “water hammer” pressure surge. The shut in process can be stopped or reversed if the pressures approach an unsafe level. Providing an alternative flow path via the choke also protects the blind shear rams from potential erosion of sealing surfaces during closure. The capping stack that was ultimately used to shut in the Well did so over a period of approximately two hours by slowly closing its choke system while pressures were closely monitored.[10]

Second, in the event that the Well is shut in and ongoing monitoring indicates a need to reopen the Well, a choke system allows an engineer to reopen the choke

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[7] *Id.*

[8] BP-HZN-2179MDL02405680.

[9] TRN-MDL-05012663.

[10] TREX 9577.

under controlled conditions. Large differential pressure across a blind shear ram can prevent it from opening.[11] For example, if the shut in wellhead pressure is 9000 psi and the ambient pressure at depth is 2500 psi, the 6500 psi pressure differential may prevent the rams from opening up again. And, in my opinion, attempting to open a blind shear ram against pressure may damage it and prevent further usage. In normal operations, the pressure differential is limited by maintaining a column of mud in the riser from the vessel above the ram. The planned choke system addressed the special problems presented by Macondo, enabled the engineering team to reopen the Well even with a substantial pressure differential, and provided confidence that the Well could be reopened if necessary.

A subsea choke and venting ability is not typically part of a subsea BOP stack. The need for inclusion of a subsea choke and vent manifold became apparent during the ongoing work to identify and mitigate risk undertaken as part of the development of various source control options in parallel. With the identified risk of overpressuring the Well, the inclusion of subsea chokes to manage pressure was a prudent and appropriate action to take.

[redacted]

[11] Deposition of Andrew Frazelle at 699-700.

[redacted]

[redacted]

[redacted]

In light of the ongoing work being done by the *Deepwater Horizon* engineering team to address the integrity of the Well and the risks posed by the capping options, I believe it was prudent to ensure that the ability to effectively manage pressure was included on any capping option. [redacted]

As noted above, on May 18, a Transocean engineer working on capping options estimated that the choke system would be available in ten to fourteen days.[14] This estimated timeframe is consistent with planning documents from both BP and Transocean that indicate that work on the development of a necessary system for relieving pressure was still ongoing. According to the BP planning chart of May 28, 2010, work on the venting manifold for the BOP-on-BOP option was still under way with manufacturing not anticipated to conclude until June 1, and installation not anticipated until June 4.[15] This is consistent with Transocean planning charts as of May 28, which show work continuing on the choke system and the BOP estimated to

[14] TRN-MDL-05012663.

[15] BP-HZN-2179MDL00332385

be ready on June 2.[16]

Similarly, May 30 emails from Cameron employees indicate work was still in progress on the BOP pressure relief manifold.[17] Wild Well Control also identified the venting option as well as the guide frame to assist in landing the BOP as the "critical path" on May 28.[18] The pressure relief system, and thus a viable BOP-on-BOP procedure, were not available when Top Kill was undertaken.

1.3 USE OF A BOP'S CHOKE AND KILL LINES IS NOT A VIABLE VENTING OPTION

Messrs. [redacted] Ziegler, [redacted] contend that venting could have been accomplished via the choke and kill lines that are part of the capping BOP that would have been landed on the *Deepwater Horizon* BOP. Those lines run back to the vessel attached to the capping BOP stack, and could not in their standard configuration be used to vent hydrocarbons safely at anything close to the rates that could be expected from the Macondo Well. It is theoretically possible that these lines could be modified to vent hydrocarbons, but they would first need to be severed from their connection to the vessel. This may potentially allow for venting, but by removing those connections the ability to circulate fluids, such as methanol, into the BOP stack, which was a critical hydrate mitigation portion of the BOP-on-BOP procedure, would be lost.[19] Additionally, the control systems on the "second" BOP's LMRP are needed to operate the choke and kill lines. If the vessel running the BOP-on-BOP option had to move away from the Macondo site due to weather or a system failure, it would disconnect the LMRP from the lower BOP stack, causing the choke and kill lines to close thereby unintentionally shutting in the Well.

Additionally, when the *Deepwater Horizon* LMRP was removed in advance of the BOP-on-BOP procedure, which would have been necessary in order to install the capping BOP, access to the *Deepwater Horizon's* BOP choke and kill lines would have been lost.[20] In contrast, the subsea choke was to be installed in the lower BOP cavity of the second BOP so that venting of pressure could continue in the event the vessel had to move off-site and remove its LMRP. The subsea choke and venting system would have been a preferable option.

1.4 TOP KILL DID NOT DELAY A CAPPING SOLUTION

[redacted]

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[16] TRN-MDL-07820789.

[17] TREX 10154.

[18] WW-MDL-00144027.

[19] BP-HZN-2179MDL02405680.

[20] The choke and kill lines were not able to be used in any capacity until they were cut and had jumper hoses attached to them on May 17, 2010 and the control system was repaired and replaced on May 18, 2010. Deposition Exhibit 9675, Stipulated Facts Concerning Source Control Events, 10-md-2179-CJB-SS (Rec. Doc. 7076 (Aug. 9, 2012)) ("Stipulations") ¶¶ 71, 72.

[redacted] The projects were being handled by separate teams and the final decision to implement Top Kill was not made until May 26.[22] As explained above, work schedules prepared at the time of Top Kill predicted that the BOP-on-BOP option would not be available until June. The three days during which Top Kill was being executed would have offered no reason for slowing work on the BOP-on-BOP option, and I have seen no evidence of such a slow down. As a Wild Well Control witness has testified, Top Kill did not in "any way delay the ability to cap the Well."[23]

1.5 BOP-ON-BOP DID NOT ENHANCE COLLECTION ABILITIES

As explained in the expert report of Mr. Dan Gibson filed on May 10, 2013, prior to Top Kill, the engineering team focused on preventing pressure increases that could cause one or more burst disks to rupture outward.[24] That issue was managed during Top Kill by keeping wellhead pressures below a predefined safe limit during pumping operations. It might have been adequately managed using a subsea venting system for the capping options. However, as shown in Mr. Gibson's report, continuing analysis and data from the Top Kill raised the concern that one or more collapse disks might have ruptured inward at the time of the explosion.[25] That meant that there could already be an open path for hydrocarbons to breach the casing, which could ultimately result in a broach to the seabed, with potentially catastrophic consequences for the Response.

Managing the risk of open collapse disks to prevent a broach required the Unified Command to keep the shut-in wellhead pressure below 4,900 psi.[26] The pressures already seen at the BOP combined with concerns about the Well's condition after analysis of Top Kill data indicated that only a limited amount of additional backpressure could be safely applied.[27] The BOP-on-BOP option was a procedure designed to shut in the Well. It did not enhance the Unified Command's ability to collect hydrocarbons which was the preferred path in light of the identified risk of subsea broach. Undertaking BOP-on-BOP would have included all of its installation risks with no corresponding upside.[28] And indeed, the BOP-on-BOP

[redacted]

[22] TREX 10682.

[23] Deposition of Patrick Campbell at Vol. 2 p. 12.

[24] *See* Report of Dan Gibson at 16 (May 10, 2013).

[25] Gibson Report at 16, 24.

[26] Gibson Report at 26.

[27] For his part, Secretary Chu appears to have concerns that excessive backpressure could be caused by the efforts to cut the riser. TREX 10687.

[28] Report of Iain Adams at 14, 17-19 (May 10, 2013) ("Adams Report").

option would have removed the ability to collect hydrocarbons from the *Deepwater Horizon*'s choke and kill lines which was successfully undertaken.

There were options to collect oil without taking these risks, namely, the Top Hat collection system, and collection from the *Deepwater Horizon* BOP's choke and kill lines.[29] Under the circumstances, it was prudent at the end of May and the beginning of June to not move forward with the BOP-on-BOP option and instead continue work on a second relief well and enhanced collection methods, while the well integrity issue was being further examined and potential mitigations investigated.

1.6 THE SUCCESS OF THE CAPPING STACK IS NOT APPLICABLE TO DIFFERENT OPTIONS

[redacted]

[redacted]

The 3-ram capping stack that was deployed in July 2010 and that successfully shut in the Well had a subsea choke system that was used to close the Well gradually (the "soft" shut-in, see p. 3 above) and manage pressure.[32] In addition to allowing pressure management, the use of the subsea choke also provides protection for the blind shear ram that is closing. As the blind shear ram is closed, the velocity of hydrocarbons flowing past it would have increased and potentially eroded the sealing elements of the ram. By having an additional flowpath for hydrocarbons out a subsea choke, the blind shear ram will see less erosional forces because the velocities across the sealing edge of the ram will be lower. The specific features of the 3-ram capping stack, all working together, produced its success. Its success certainly does not prove that a differently configured, higher risk capping device would have been successful at an earlier point in time.

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[29] The Top Hat was a dome like device that collected hydrocarbons exiting the *Deepwater Horizon* BOP after the riser was cut. Stipulations at 3. Using the piping set up for the Top Kill efforts, the *Q4000* and *Helix Producer 1* collected hydrocarbons from the *Deepwater Horizon*'s choke and kill lines. Stipulations at ¶¶ 132.

[redacted]

[redacted]

[32] BP-HZN-2179MDL01518848.

2.0 TOP KILL WAS REASONABLE AND DID NOT DAMAGE THE WELL OR LIMIT FUTURE OPTIONS

[redacted] flow rate was not critical to Top Kill -- pressures in the flowing system and the size and location of chokes in the flow path (unknown in May 2010) were critical.

The main driver of whether injected material will initially form a bridge is the relationship between the size of the material and the size of the orifice that it encounters. [redacted] However, the primary issue there is still the relative size differential between the injected material and the orifice. In addition, velocity as it would affect distortion of bridging material is not directly related to overall flow from the Well, but is dictated by the particular pressure and flow path geometry it encounters.

[redacted] As bridging occurs the flow rate decreases, but pressure increases due to the newly restricted flowpath. The risk of pressure increasing to an unsafe level was an identified risk that the Top Kill team was able to mitigate, in part by injecting only a measured amount of materials at a time.[33]

The major risks of Top Kill were identified and mitigated.[34] While Top Kill was not successful in killing the Well, it did not create any of the potentially adverse outcomes identified (except perhaps some erosion within the BOP). A fundamental problem with the engineering judgment of the reports submitted on behalf of Transocean and Halliburton is that they consider risk asymmetrically. For example, the risks identified and mitigated for the Top Kill procedure are highlighted by the Transocean and Halliburton reports as a reason to not attempt that operation, while the risks identified and mitigated for the BOP-on-BOP option are ignored.[35] The BOP-on-BOP option had its own risks, and a proper comparison of the BOP-on-BOP option and Top Kill should include an evaluation of the risks and mitigations of both, the availability of both, and the impact of either procedure on future options if unsuccessful. It is certainly true that the engineering team working on BOP-on-BOP

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33 Deposition of Charles Holt at 539-540. [redacted]

34 Adams Report at 9-10.

35 [redacted] Ziegler Report at 33; [redacted]

believed it to be a feasible procedure and was working to be able to implement it. But risks being evaluated by different teams, namely risks involving the integrity of the Well, were not part of the remit of the BOP-on-BOP engineering team. The risks presented by well integrity concerns properly prevented implementation of the BOP-on-BOP option at the end of May 2010.[36]

3.0 CAPPING STACK TIMELINES ARE NOT DETERMINABLE IN ADVANCE

The assertion put forward by Mr. Ziegler [redacted] that a capping stack could have been installed in seven or eight days is implausible.[37] Surface wells, where capping techniques have a long history, routinely take much longer than eight days to cap. Intervention teams responding a land well blowout are able to roll equipment on trucks into close proximity with the wellhead. The Macondo Well was 5,000 feet below the surface of the Gulf of Mexico. Given the location of the Macondo Well, intervention was far more complex than what would be required for a surface blowout. Mr. Ziegler [redacted] base their seven- to eight-day timeline on comments presented at a conference after the Macondo event. At that conference, one speaker offered an opinion that because removal of the debris took what he estimated to be five days, and the actual deployment of the 3-ram Capping Stack took three days, shut-in of the Well could be accomplished in eight days. The eight-day timeframe ignores key aspects of the capping stack's installation, such as the straightening of the flexjoint with which the conference speaker may not have been familiar.[38] The eight-day timeframe also ignores the substantial time needed to evaluate concerns about the integrity of the Well, as well as other the peer reviews, safety evaluations, and risk mitigation activities necessary to shut in the Macondo Well. As I stated in my May 10 report, no one can predict with a reasonable degree of engineering certainty how long it would have taken to shut in the Macondo Well, even if a capping stack had been prebuilt.[39]

[redacted]

[36] TREX 10505 (noting that peer review was limited to "installation risks").

[37] Ziegler Report at 36-38; [redacted]

[38] Adams Report at 22.

[39] *Id.* at 23-27.

[redacted]

[redacted]

5.0 ADDITIONAL ERRORS AND ISSUES IN MR. ZIEGLER'S REPORT

In addition to the points noted above, Mr. Ziegler's report contains other assertions that are not consistent with my engineering judgment and understanding of the available information.

- Mr. Ziegler asserts that the Top Hat failed.[44] That is incorrect. Top Hat #4 was installed on June 3 and successfully collected hydrocarbons to the *Discoverer Enterprise* with limited interruptions before being removed for the installation of the 3-ram capping stack.[45]

- Mr. Ziegler implies that the *Deepwater Horizon* LMRP was removed subsea in support of his argument that BOP-on-BOP was feasible at Macondo.[46] The *Deepwater Horizon* BOP stack was, in fact, recovered as a single unit by the *Q4000*, which is standard practice for stack recovery.[47] The LMRP was removed on the deck of the *Q4000*, which is a vastly different operation than removing it in 5000 feet of water in dynamic well conditions.[48] The source of Mr. Ziegler's assertion, a deposition of a Cameron representative, does not contradict these facts.

- Mr. Ziegler asserts that BP was "paralyzed" because it lacked a flow rate estimate.[49] This is incorrect. Admiral Allen has testified that flow rate did not direct the Response.[50] Multiple workstreams were moving forward as quickly as practicable and possible, and decisions were being made and vetted by the Unified Command as options became available.

[redacted]

44 Ziegler Report at 35.

45 Stipulations ¶¶ 91, 92, and 121.

46 Ziegler Report at 40.

47 IMS018-002899.

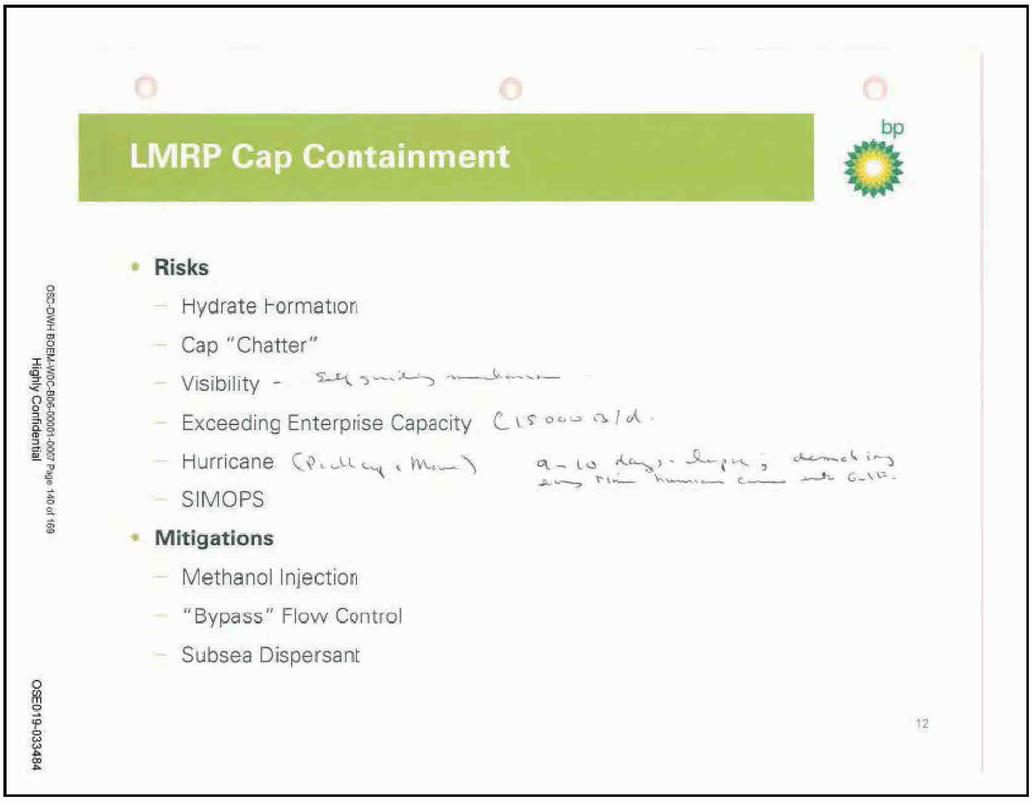
48 *Id.*

49 Ziegler Report at 27.

50 Deposition of Admiral Allen at 210-12.

6.0 COLLECTION EFFORTS ESTABLISHED FLOW RATES

The reports filed by Transocean and Halliburton either state outright or imply that BP made recommendations to avoid disclosing or suggesting a flow rate above 15,000 bpd could be responsible for the failure of Top Kill. In addition to having seen no actual evidence of this theory presented, it is implausible. As explained in the report of Dan Gibson, the ongoing analysis of well integrity and data from Top Kill suggested a potential issue with rupture disks that might have allowed a subsea broach to occur if the Well was capped. That possibility led the Unified Command to pursue collection efforts that would not add excessive pressure to the Well. While the Unified Command was moving to its collections strategy, BP made a presentation to Secretary of the Interior Salazar that explained the concerns about the integrity of the Well and the planned containment options. One of the risks identified for the Top Hat was flow "Exceeding Enterprise Capacity."[51] The *Enterprise* had the capacity to collect approximately 15,000 bpd, which was discussed at this presentation and, as shown below, noted by a government participant.



OSE109-003484.

BP's proposed plan after the Top Kill data was analyzed was to implement a containment system -- the Top Hat -- which, if implemented, would prove the Well was flowing at greater than 15,000 barrels per day, if discharge from the Well

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[51] OSE109-033473.

exceeded the capacity of the *Enterprise*. On the fourth day of collection with the Top Hat, almost 15,000 barrels were collected.[51] On the fifth day of collection, more than 15,000 barrels were collected.[52]

In early June, BP was also preparing to flow hydrocarbons to the *Q4000*, which could process approximately 8000 bpd. The *Q4000* began operation on June 16, which gave approximately 23,000 barrels of processing capacity between it and the *Enterprise*. With this combined collection rate, it was confirmed that the Well was in fact flowing at a rate above 23,000 bpd in June.[53] And additional capacity was under development. There is no reason to pursue these collection methods, which prove a flow rate upwards of 23,000 bpd, to avoid the conclusion that Top Kill failed due to a flow rate exceeding 15,000 bpd.

In summary, if there was a desire to avoid a conclusion that flow from the Well was greater than 15,000 barrels per day, and there were not concerns about well integrity, the obvious answer would have been to simply attempt to cap the Well. It would not have been in either the public interest or the interest of BP to shift to the collection strategy.

CONCLUSION

My review of the reports by Messrs [redacted] Ziegler and Drs. [redacted] Wilson does not change my conclusion that BP's participation in the Unified Area Command's Response to the *Deepwater Horizon* blowout demonstrated sound engineering judgment, gave appropriate attention to the safety of workers engaged in the Response, and enabled the Unified Command to close the Well as expeditiously as practicable, taking due account of uncertainties about the condition of the Well and the need to minimize the risk of subsea broaching while mitigating environmental damage to the extent possible.

Prepared by:	Iain Adams	Date
Signed	Iain Adams	June 10, 2013

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[51] TREX 9490

[52] *Id.*

[53] *Id.*

RETENTION FOR THIS MATTER

In 2012, BP retained me to work on this litigation. For my services in this matter, I am being compensated at my customary hourly rate of 400 GBP per hour. My compensation does not depend in any way on the outcome of this litigation or the conclusions that I reached.