From: Bromwich, Michael R
To: Tompkins, Hilary C; Jacobson, Rachel; Rogers, Constance;
cc: Beaudreau, Tommy; Bakalov, Raya;
Subject: Fw:
Date: Tuesday, June 29, 2010 8:32:18 AM
Attachments: Bromwich Memo 6-29-2010.pdf

The signed version of the information collection memo.

MRB

From: Barre, Michael
To: Bromwich, Michael R
Sent: Tue Jun 29 06:28:55 2010
Subject:

Mike Barre
Office of the Director
Bureau of Ocean Energy Management,
Regulation and Enforcement
1849 C Street, N.W., Room 5412
Washington, DC 20240
[redacted]

EXHIBIT 1

JUN 2 9 2010

MEMORANDUM

From: Michael R. Bromwich

To: Walter Cruickshank
Mary Katherine Ishee
Robert LaBelle
Lars Herbst

Subj: Information Gathering on Safety and Environmental Issues

In order to inform decision making on future actions to address safety and environmental concerns posed by offshore oil and gas development, please prepare responses to the following questions, and identify any documentation and data from any source that support your responses.

1. What do the preliminary and current investigations, research, data, reports, or other information on the Deep Water Horizon Explosion at the Macondo Well Blowout identify as potential risks of deepwater drilling with respect to the following factors:

    a. Integrity of well casing;
    b. Production seal assembly;
    c. Integrity of casing cement;
    d. Casing hanger seal assemblies;
    e. Integrity of testing to identify flow paths for hydrocarbons from reservoir to surface
    f. Blowout preventer and emergency system:

        i. Testing on surface
        ii. Testing in subsea
        iii. Adequacy of activation of redundancy system
            1. Emergency disconnect system
            2. Deadman switch failure
            3. Auto shear capability
            4. Backgroup
        iv. BOP activation systems

2. Do we know if these risks or any other risks are present on current operations, if so which ones?

3. Would implementation of the 22 safety measures identified in the 30-day report reduce the risks identified in items 1 a-f above? If so, describe how.

4. What is the estimated length of time necessary to implement each safety recommendation in the 30-day report?

EXHIBIT 1

5. Describe BP's efforts and any challenges encountered to stop the blowout of the Macondo well since April 20, 2010.

6. How can we assure that operators faced with a blowout in the Gulf of Mexico could handle well containment more effectively than ongoing efforts at Macondo well? Is well containment affected by depth of operations?

7. Are current oil spill response plans for deepwater drilling operations adequate to prevent the type of environmental consequences resulting from the Macondo well blowout?

8. What are the relative risks of failure of safety and operational equipment at various depths? Does the placement of blowout preventers at the surface or subsea affect the relative risk of failure?

9. Are there any improvements or changes that could be made to current inspection procedures and practices that would enhance safety and environmental protection?

10. Does the fact that the root cause of the BP blowout remains unknown have any relevance in the oversight and regulation of deepwater drilling operations?

11. Based on the foregoing questions and any other identified risk factors, please provide options for proposed actions to ensure safe and environmentally protective drilling in the OCS, including the viability of an option for addressing these issues on a case-by-case basis. Please make sure each of your options considers the following factors, if applicable:

- Justification and rationale for nature and scope of proposed action, i.e., what facts support the proposed action.
- Whether the proposed action should be applied to rigs individually or more broadly.
- Justification for water depth selection, if relevant, of proposed action.
- Nature of risk and associated harm in absence of proposed action.
- Description of known safety hazards and how those will be addressed by proposed action.
- Length of time necessary to implement proposed action.
- Effects of proposed action on operators and associated service providers.
- Whether operations must be suspended to implement the proposed action, and if so, for how long. In addition, are there terms and/or conditions that an operator could fulfill that would justify a lifting of the suspension for that particular operator?

[redacted]

July 2, 2010

MEMORANDUM

TO: Mike Bromwich, Director, BOEMRE

FROM: Walter Cruickshank, Deputy Director, BOEMRE

SUBJECT: Summary of Macondo Well Intervention and Containment Efforts and Testing and Performance Issues with BOPs for Relief Wells

The following summarizes specific well control and containment efforts for the Macondo well blowout, and testing and performance difficulties encountered with the blowout preventers (BOPs) being used for the two relief wells being drilled to intercept and kill the Macondo well.

This summary timeline is based on information in MMS/BOEMRE's Offshore Incident Report Final Daily Updates, DOI Office of Emergency Management's (OEM) daily (or twice-daily) Emergency Management Daily Situation Reports and Updates, and OEM's occasional Spot Reports. Additional information on testing of the relief well BOPs was provided by the New Orleans District staff that witnessed the tests.

EFFORTS TO ACTIVATE MACONDO WELL BOP

After the failure of surface efforts to activate the BOP after the explosion on April 20, on April 21, attempts were to activate the BOP by (remotely operated vehicle) ROV. The ROV cut hydraulic lines due to concerns that the BOP might be hydraulically locked; then the ROV hot stabs the BOP and pumped up the hydraulics to close the pipe rams. In this attempt, there appeared to be either a valve alignment problem or an ROV problem. The ROV had to be pulled to the deck of the vessel and another ROV was deployed.

The ROV then cut the steel rod connecting the riser. This should have activated the deadman switch and closed the BOP stack, but it did not. A higher volume ROV is brought in to hot stab into the pipe rams. This did not work either.

As of April 24, intervention efforts continued to focus on attempts to activate the variable bore rams and blind shear rams on the BOP, which were ineffective because of hydraulic leaks and ROV problems. There were also inherent difficulties presented by having to use ROVs at this depth, and by the intense pressure at the bottom of the well. Under those pressures, flows containing abrasive particles such as small pieces of rock will cut through metal. BP and Transocean have recovered small rocks from the deck of the *DAMON BANKSTON*, and these rocks have been subpoenaed for the joint BOEMRE/ USCG root cause investigation, with USGS performing the testing. This high-velocity flow may have eroded part of the BOP, rendering ineffective any control that the BOP is providing.

EXHIBIT 1

[redacted]

As of April 25, BP was unsuccessful in actuating the variable bore rams, and was not sure whether it had pressure integrity on the hydraulic system on the stack. No further attempts to activate the BOP to shut in the well are documented in the referenced reports.

CONTAINMENT EFFORTS ATTEMPTED

Numerous technologies and strategies were conceived to stop the blowout, other than attempting to activate the BOP. None were prepared, constructed or ready to be deployed at the time of the uncontrolled Macondo blowout. None of the strategies conceived or utilized had ever been used in the water depths of the Macondo well. Below are the difficulties encountered with major strategies attempted to control or contain the flow from the Macondo well.

Relief well

On April 26, the first relief well EP was approved, but the spud date for the relief well was delayed because of the need to collect and analyze two-dimensional high-resolution data. Rigs were not immediately available, and no plans were prepared.

Containment Dome/Coffer Dam

As of April 28, the collection dome (alternatively identified in the reports as the collection done, containment dome and coffer dam) strategy's estimated startup was estimated at 3-4 weeks out. Nine days after the explosion, on April 29, design and fabrication the containment dome began onshore. BP estimated in an announcement that it will take four weeks to design, build and deploy the coffer dam.

On May 7, the coffer dam was deployed over the largest plume at the end of the riser. Methane hydrate crystal build-up within the containment dome rendered it too buoyant to function as planned. On May 8, failure of the coffer dam containment system was conceded.

Valve on Drill Pipe

On May 1, the ROVs finished the cut on the drill pipe end in preparation for placing a valve to cap the leak at this location. On May 3, plans to insert a valve at the end of the drill pipe were delayed because of tool breakage. Another tool was lowered to the seafloor before the valve could be installed to plug the leak from the end of the drill pipe. Weather issues also caused delays. On May 5, ROVs were used to install a valve on the end of the broken drill pipe, one of three points from which oil was leaking. The ROVs joined the valve to the broken drill pipe and closed it, shutting off the flow from that pipe. This stops the flow from this point. There was no change in flow in any of the other plumes, indicating that the drill pipe is parted somewhere in the riser, and the flow that is coming from the drill pipe is probably coming from the riser.

[redacted]

RITT

On May 13, the riser insertion tube tool (RITT), was on deck at location and ready to be deployed. After complications on May 13 with the RITT, on May 14 the *Poseidon* moved on location to retrieve it, with hopes to be able to run the RITT back to the sea floor mid morning and insert it by late afternoon. On May 15, the RITT fell over on the first attempt to connect the RITT to the bottom hole assembly. It was brought to the surface to correct the problem, repaired, lowered to the seafloor, and latched onto drill pipe in preparation to insert into the end of the riser. On May 16, the RITT was successfully tested and inserted into the leaking riser, capturing some oil and gas. The oil was stored on board the *Enterprise* drill ship, and natural gas was burned through a flare system on board the ship. The test was halted temporarily when the tube was dislodged, but technicians re-inserted the tool.

On May 20, methanol continued to be injected to prevent build up of hydrates. A second RITT was in port preparing to be moved onto location. BP worked to remove hydrates from the mud boost line.

On May 23, the RITT was believed to have shifted in the riser. It was repositioned to center it into the liquid portion of the flow. A third RITT was being designed.

On May 26, top kill operations commenced and the RITT was removed. Hydrates were removed from the bottom of the LMRP that had built up while using the RITT.

On May 29, a new RITT and new top hat for the LMRP were being prepared, to be used until the riser removal operation. This work could take from 4 to 7 days. Alternatives under consideration included removing the LMRP to install a BOP-on-BOP. On May 30, the new RITT option was abandoned. Following failure of the top-kill operation on may 29, the BOP on BOP option was abandoned.

Top Kill

On May 3, BP planned to retrieve the "blue pod" – one of the controllers of the BOP – but decided later in the day to remove the yellow pod instead because of difficulties in getting to the blue pod due to its location near the kinked riser.

On May 10, work was performed on the BOP in preparation to attempt a top kill operation aimed at stopping the flow of oil from the well. All of the techniques attempted or evaluated to contain the flow of oil on the seabed involve significant uncertainties because they have not been tested in these conditions before. On May 12, the yellow pod was ready for re-installation on the BOP to assist in the top kill/junk shot.

On May 15, an attempt was made to connect the jumper that is to connect the junk shot manifold to the choke/kill lines. The connection was unsuccessful and the jumper was brought back to the surface for evaluation. On May 19, the yellow pod was installed on the BOP and able to control the valves on the LMRP.

[redacted]

On May 22, work continued in preparation for the top kill operation. A ball valve had been leaking and was being repaired. On May 23, a light duty intervention system (LDIS) installed for the top kill repeatedly developed leaks when lowered to the seafloor.

On May 24, pressure testing took place on surface and subsurface equipment in preparation for top kill operation. BP claimed that it would know within four hours of commencement if the top kill operation was effective. On May 26, the top kill operation began. The RITT was removed, and preparations were made for the LMRP top hat, if needed.

On May 27, a second pumping of mud for top kill operation commenced, to continue for up to 24 hours. Mud injection rate went as high as 65 barrels per minute.

Top kill operations continued on May 28. It was estimated that the full top kill procedure could extend for another 48 hours. The top kill temporarily was halted because not enough mud was available on site. On May 29, the top kill ended, without success.

Top Hat

May 10, a second, smaller containment dome was readied to lower over the main leak point. The small dome was to be connected by drill pipe and riser lines to a drill ship. It was designed to mitigate the formation of large hydrate volumes. On May 11, preparations for the top hat procedure continued, and the top hat was lowered to the seafloor.

On May 12, the top hat was being modified and expected to be on site by mid-week. Additional equipment for this procedure was being installed on the *Enterprise*. On May 13, work to deploy a second containment system continued. Deployment of this "top hat" system was expected to be attempted within the next few days. This did not happen as the top kill operation was implemented first.

After failure of the top kill operation, on May 30, a new top hat option was planned. This plan involved cutting and then removing the damaged riser from the top of the BOP to leave a cleanly-cut pipe at the top of the BOP's LMRP, to place a new top hat cap. The cap was designed to be connected to a riser from the *Enterprise* and placed over the LMRP with the intention of capturing most of the oil and gas flowing from the well.

On May 31, the riser and associated piping were being cleared away from the top of the well. The preference was to use a lead LMRP top cap, the extra weight providing a better seal, but lead top cap was not available for another day. Installation of the new LMRP cap could take 4-7 days, during which time oil flow increased substantially.

On June 1, the first shear cuts were made to remove the riser. The plume at the end of the riser in the trench ceased and ensued from the end of the new shear cut. On June 2, after the upper portion of the riser was sheared, work continued to remove the riser from the stack. The saw blade making the incision 6-12" above the BOP had to be unstuck, and the decision was made to use shear jaws to complete the cut. This would leave an uneven cut

[redacted]

and caused some concern about the seal of the top cap. The lead LMRP cap was on location ready to run to the seafloor, but the uneven cut caused by the shear forces transition from lead-weighted top cap to top hat.

On June 3, the shear cut removed the top of the riser, and much of the day was spent grinding the cut. There was some delay in stabbing the top hat because the ROVs had difficulty keeping the methanol injection hoses out of the way. The ROVs could not hold the hoses out of the way during injection due to the reaction of the plume. Video of the removed piece of the riser shows two pieces of pipe in the kink in the riser. There was no explanation for this.

On June 4, the top hat had been stabbed and contained the first gas and oil to surface, though substantial oil continued to flow through the open vents. On June 5, the LMRP top hat appeared to be working and was in the process of ramping up production to the surface. Oil is separated and gas flared. A tanker would offload the produced oil. A leak on the *Enterprise* forced the temporary shutdown of production from the top hat.

On June 6, the leak on board the *Enterprise* was fixed and top hat production recommenced. On June 7, recovery on the *Enterprise* was at capacity. A solenoid on the blue pod also needed to be replaced. On June 13, the top hat was observed to be listing at about 10 degrees. On June 14, the top hat was now listing at about 12 degrees, and three of four vents remained open.

One June 15, a lightning strike on *Enterprise* shut down production from the top hat while systems were checked. The pressure gauge that was inserted in the hot stab on top of the top hat was consistently reading 2.4 psi – with the shutdown, it had been expected that the pressure reading would have increased, but this did not occur, which made the readings suspect.

On June 17, weather caused a 50-minute shutdown on the *Enterprise*. On June 19, the *Enterprise* shut down due to pressure build-up in the cargo tank. The cause appears to have been a plug in a flame arrestor, possibly the same one that had been struck by lightning previously. After weather delays, the *Enterprise* came back online. On June 23, the *Enterprise* temporarily halted operations as a precaution and moved off location due to what was thought to be hydrocarbons entering the riser. While the system was disconnected, there was uncontained flow from the wellhead. Investigation found one of the two manual valves at the base of the LMRP, where the warm water is circulated out the riser, had closed. After testing the production systems and checking for hydrates, the *Enterprise* moved back on location and reinstalled the top hat that evening. Flow was expected to reach the vessel overnight.

Dual Flow Containment Option

In concert with the top hat operation, a system to access the BOP choke and kill lines to remove flow was also developed. The flow from these lines will be flared. The *Q4000* is designed to collect flow from the choke and kill lines off the stack, to extract excess production that the *Enterprise* cannot accommodate, while trying to make sure not to

[redacted]

draw down the flow to the point where water is drawn into the top hat. On June 15, *Q4000* operations began. On June 16, the heat of the *Q4000* plume from flaring was becoming an issue. On June 17, two fire boats were spraying water on the *Q4000* plume to keep the heat down. Production on *Q4000* during the daylight hours was cut back because of the heat issues. On June 18, the *Clear Leader* was projected to be at the staging area June 21 to receive flow from the kill line, but at least a week of work would follow.

Containment and Disposal Project (CDP)

As of May 31, the team also began working on a more permanent system that would be used to recover the fluids during hurricane season. The flow would then be directed through a self-venting manifold and up a free-standing riser to the surface.

On June 3, the manifold that is to be used for the long-term option for hurricane season finishes factory testing and was expected to be installed in another week. On June 8, BP was ordered to have redundant systems for both the near term containment system and the long-term CDP. On June 12, MMS conducted inspection of the vessels necessary for the long term CDP option and identified two main issues that would need to be addressed before implementation. On June 18, work proceeded on a second free-standing riser, using the *Toisa Pisces*, expected on site June 23. As of June 30, 2010, the CDP option had not been deployed.

TESTING AND PERFORMANCE ISSUES WITH RELIEF WELL BOPs

The following summarizes the BOP testing for the 2 relief wells.

Relief Well drilled with the Transocean Development Driller II

<u>Stump Test Summary</u>

1. ROV Hot Stab Testing

Several LMRP and BOP stack hot stab functions were conducted with the actual ROV pump. The LMRP disconnect function was unsuccessful because of a leaking shuttle valve. After several attempts to repair the valve, the disconnect function was successfully conducted. NTL No. 2010-N05 requires this function.

NTL No. 2010-N05 also requires the testing of a pipe ram and a blind shear ram. The DD II does not have a pipe ram function on its BOP stack hot stab panel. It does have two blind shear rams and two blind shear ram hot stabs on it BOP stack panel. Both blind shear rams were successfully closed in the function test.

Other functions that were successfully function tested were the casing shear ram close and wellhead connector unlatch. An unsuccessful function test was the All Stabs Retract function. After several attempts to repair a shuttle valve which had failed, the function was successfully tested.

[redacted]

2. Emergency Disconnect System (EDS) Testing

EDS testing for the casing and drill pipe sequence was conducted and everything worked according to specifications. It was tested electronically (dry) and hydraulically (wet).

3. Deadman Testing

Performed a deadman testing. There was significant problem with the BOP design and testing for the deadman. BP's plan was to not use the BOP accumulators, and install a mobile accumulator to test the deadman that would bypass components within the deadman circuit. BOEMRE required them to test the deadman with the BOP accumulators and a major problem was found. The deadman circuit would not function. Troubleshooting occurred for several days, and the problem was determined to be a design issue. A shuttle valve was improperly installed into the deadman circuit so it would not allow a deadman scenario (a complete loss of hydraulics and electricity) to be initiated. With this shuttle valve installed, it would always allow hydraulic pressure to be received and would never allow the deadman to release hydraulics from the solenoid to activate the deadman sequence. The shuttle valve was taken off the deadman circuit and the deadman worked as designed.

4. Component Pressure Testing

Pressure testing of the BOP components was successfully conducted with no issues.

<u>On-Bottom Testing</u>

1.ROV Hot Stab Testing

Function tested the upper blind shear rams closed with ROV. Confirmed successfully closed via 5 min pressure test to 1000 psi.

2. Deadman Testing

The deadman test was conducted successfully, closing the casing shear rams and lower blind shear rams. The lower blind shear rams were confirmed closed via a 250 psi test. Upon function testing of blind shear rams and casing shear rams on both pods, the blue pod was unable to close the casing shear rams. The BOP stack was pulled to find the problem. The problem was identified as the solenoid connection; it was repaired, the stack was rerun, and the casing shear rams were successfully closed.

3. EDS Testing

Not conducted on bottom

4. Component Pressure Testing

EXHIBIT 1

[redacted]

All required components were successfully pressure tested.

Relief Well drilled with the Transocean Development Driller III

Stump Test Summary

1. All pertinent hot stab functions on the LMRP and BOP stack were successfully tested via the ROV auxiliary pump. The auxiliary pump had been calibrated to the same rate and pressure as the ROV pump. The actual ROV pump could not be used for all of the testing because of overheating concerns, but it was used to calibrate the auxiliary pump.
2. There was a complete hydraulic actuation of the EDS that was successful. Also dry testing of the EDS was conducted from remote panels.
3. A deadman test was unsuccessful because of a failed SPM valve that dumped hydraulic control fluid before it could be transmitted to the casing shear ram to activate its closing. This test is not normally conducted as part of the stump test. After repairing the SPM valve (and two others – one for "chattering," which indicated possible near term failure, and the other one for precautionary measures since it was the only other SPM valve in the 3 valve circuit), the deadman test was conducted successfully.
4. The pressure tests of all components were successful and had no issues.

On-Bottom Testing

1. ROV closing of the upper blind shear ram; confirmed closed via 1000 psi pressure test.
2. Deadman test conducted successfully; confirmed lower blind shear ram closed via 250 psi pressure test.

Sources:
Minerals Management Service, Gulf of Mexico Region, Offshore Incident Report Final Daily Update (Respective dates between April 21 and June 30 2010).
Department of the Interior, Office of Emergency Management, Spot Reports: Offshore Oil Rig Explosion With Mass Casualties, Venice, Plaquemines Parish, LA (Respective dates between April 21 and June 30 2010).
Department of the Interior, Office of Emergency Management, Emergency Management Daily Situation Report (Respective dates between April 21 and June 30 2010).
E-mail message from Michael Saucier, Regional Supervisor for Field Operations, Gulf of Mexico Region, BOEMRE, to Walter Cruickshank, Deputy Director, BOEMRE, with subject line: "Relief Well BOP Testing Summary" (July 1, 2010)

[redacted]

<u>Five basic points in support of a drilling moratorium:</u> There is ample and uncontradicted evidence to support each of the following propositions.

1. As evidenced by the API joint industry recommendations and other voluntary submissions by industry representatives (e.g., industry letters in response to April 30 meeting and follow up correspondence from BP and other majors), <u>industry drilling and safety practices and procedures, especially those with respect to ultra deep wells drilled from floating vessels, fall short of best practices</u>. In a series of detailed recommendations prepared for the Department within a few weeks of the Macando well blowout, representatives of a broad cross section of industry, including rig owners and operators, drilling contractors, lease holders and their respective trade associations, jointly and candidly acknowledge the need to raise the bar with respect to a number of industry drilling and safety practices and procedures. Those recommendations formed the basis for many of the safety recommendations contained in the Secretary's 30-day report to the President. While some can and have been implemented through the first (safety) NTL, others will require three to six months to develop, as noted in the API JITF white paper.

2. Likewise, <u>the Department recognizes that its own regulations and inspection program fall short of what is needed to ensure safe and environmentally responsible development of oil and gas on the OCS</u>. In connection with preparation of the 30-day Safety Report, the Department retained Elmer ("Bud") Danenberger, former Chief, Offshore Regulatory Programs, to review MMS's current regulations, various MMS-funded research projects, as well as regulatory programs in Norway, the United Kingdom and elsewhere and to make recommendations to the Department for improving MMS's regulations, enhancing its safety management programs and bolstering its inspection program. (Danenberger, Elmer P., Suggested Revisions to Regulations, 5/20/2010 draft) Mr. Danenberger's report formed the basis for several of the safety recommendations contained in the 30-day Safety Report. It, together with the joint industry recommendations and other information developed in connection with preparation of the 30-day report, shows that there are substantial gaps and other shortcomings in current regulations governing offshore drilling. The 30-day Safety Report makes specific recommendations for filling those gaps and improving MMS's (now BOE's) regulations. Some of those recommendations can be implemented through an interim final rule, and thus made effective immediately (i.e., upon publication of the interim final rule), but others will require further development by Department-led work groups and with the benefit of industry and other stakeholder input. That process is estimated to take at least six months to one year (or more) to complete.

[redacted]

3. The BP oil spill/Macando well blowout – and more specifically BP's failure to kill the well and contain the spill – demonstrates that industry does not have the technological capability to stop an uncontrolled blowout of an ultra deep well, especially in deep water. Short of a relief well, which in this case will take more than three months to drill and has its own attendant risks of failure – hence the redundant second relief well – there apparently is no fail-safe method to prevent another environmental disaster of this magnitude, should another ultra deep well fail. While it is not the federal government's responsibility to stop a wild well, the BP oil spill also demonstrates the limited nature of the government's technological capabilities. In the absence of any means to contain another blowout, and given the proven environmental and economic consequences of another oil spill, it would be irresponsible to permit any new drilling activity with a measurable risk of failure without also requiring the simultaneous drilling of at least one relief well.

4. The unprecedented deployment of spill response equipment and cleanup crews to the area in the vicinity of the Macando well and to nearby shorelines calls into question industry's and the federal government's ability to respond in a meaningful way to another spill of a similar (or even a much smaller) magnitude.

Oil Spill Response Assets On-Scene – June 27, 2010	
Personnel	38,927
Deployed Boom (Feet)	7,659,405 Total
Vessels	6,458*
Fixed Wing Aircraft	37*
Helicopters	72*
*Number does not include staged or ordered assets	

Source: DOI Office of Emergency Management, Emergency Management Situation Report, Gulf of Mexico Oil Spill, June 28, 2010

In addition, provisions have been made to suspend certain oils spill response time requirements in order to assist in the need for immediate relocation of nationwide oil response recourse to the GOM. (USCG 33 CFR 154 and 155; EPA 40 CFR 112) At a minimum, therefore, and putting aside for the moment the legal question whether GOM spill response plans are still valid, there is a substantial question whether industry or the federal government could deploy the assets necessary to respond to another catastrophic oil spill in the GOM or elsewhere. Again, unless and until an operator or lessee can demonstrate the capacity promptly to respond to and cleanup another spill, however unlikely, it would be irresponsible (and arguably unlawful) to permit new drilling activity with a measurable risk of failure.

The economic and environmental consequences of another oil spill of equal or comparable

[redacted]

magnitude to the BP oil spill (even one of a much lesser magnitude) would be socially unacceptable. The BP oil spill is estimated to cost the company _____, not including _______. Response costs incurred to date exceed $2.65 billion. (*Faucon, Benoit, UPDATE,Wall Street Journal, June 28, 2010, < http://online.wsj.com/article/BT-CO-20100628-701871.html>*) Direct and indirect economic impacts of the BP oil spill are likely to exceed ______. And natural resource damages will likely exceed _______. This disaster has been called the worst environmental disaster in the Nation's history. (President's Remarks from Oval Office - June 15, 2010 <http://www.whitehouse.gov/the-press-office/remarks-president-nation-bp-oil-spill>) Plainly, while the risk of another spill of equal or similar magnitude may be small, it is not zero. The country simply cannot afford another disaster like the current one. Therefore, until the safety recommendations are implemented (and rig operators and lessees demonstrate compliance with NTL No. 2010-N05 and NTL No. 2010-N06 and other applicable requirements) and until industry [and the federal government] can demonstrate the ability to contain a wild well and adequate spill response plans, the risk and potential consequences of another spill are unacceptably high.

A drilling moratorium should be narrowly tailored to address these concerns.

1. First, not all drilling activities are alike. And not all formations are alike. The risk profile for drilling a new exploratory well into an unknown formation in deep water from a floating vessel (especially an ultra deep well) differs substantially from the risk profile for drilling a development well into a known formation in shallow water. (Expert's Presentation to the Secretary of Interior, June 21, 2010) Between those extremes, it is possible to list the number and type of drilling activities for which the risk of an uncontrolled blowout is minimal or nonexistent. For any such activities, weaknesses in industry's containment and spill response capabilities (e.g., technologies and assets necessary to protect the environment, as framed by the first two points above) presumably are less of an immediate concern; but the federal government's legitimate interest in workplace safety argues for immediate adoption of industry best practices and implementation of new safety regulations. Therefore, even for permitted drilling activities, a brief "pause" of sufficient duration to implement certain of the safety recommendations is warranted. [See, e.g., API JITF "Possible Proposals to Allow Resumption of Drilling Operations" (submitted June 25, 2010).]

2. Second, not all operators are alike. Some companies have proven track records of safe operations, built on a foundation of sound (best) drilling practices and procedures and a strong safety culture. One measure of safe performance may be the relative number of instances of non-compliance or "INCs," while another may be adherence to industry best practices and use of generally accepted risk assessment and risk mitigation tools, as verified by an independent third party. (Safety NTL, No. 2010-N05, General Certification of Compliance with Existing Regulations (30 CFR 250) and National Safety Alert) In

[redacted]

either case, and subject to a showing of adequate spill containment and response capabilities(?), it may follow that certain operators should be permitted to drill new wells notwithstanding a moratorium. This kind of case-by-case evaluation would require a significant amount of agency resources, however, and would be difficult to administer.

3. Third, inasmuch as implementation and adoption of the safety recommendations contained in the 30-day report will, we expect, materially increase the margin of safety for offshore drilling, it may follow that <u>operators that can demonstrate compliance with all or some of the new safety requirements should be permitted to drill</u>. To a lesser extent, that is true even of the limited number of requirements contained in the Safety NTL (No. 2010-N05).

<u>A moratorium should be time limited</u>. The length of a moratorium should bear a reasonable relationship to the need to address each of the issues identified above. Thus, it should be of sufficient length to (1) allow for implementation of the Safety NTL and other urgent safety recommendations from the 30-day Safety Report (i.e., those that can be implemented by an interim final rule), (2) complete the root cause investigations into the Macondo incident/BP oil spill, and (3) allow the Presidential Commission to report, even if on a preliminary basis, its findings and recommendations.

<u>Arguably, a moratorium should include a set of criteria which, if satisfied, would allow rig owners/operators/drilling contractors to resume drilling operations.</u>

1. BOEM memos (LaBelle, Hauser, and Herbst) offer many good suggestions.
2. API JITF Memo (June 25, 2010) offers some suggestions – but sets the bar relatively low.

EXHIBIT 1