Discussion of challenges for 24/7 inspection coverage for GOMR and possible alternative methods for achieving increased MMS inspection presence

Introduction

In the aftermath of the BP Horizon Incident, there has been much discussion as to whether MMS should implement some type of increased offshore inspection presence. This paper attempts to outline some of the pertinent issues that must be addressed in developing an inspection strategy.

Offshore rig counts prior to 6-month moratorium

Prior to the 6-month moratorium on deepwater drilling, there were 33 drilling units working in deepwater utilizing subsea BOP stacks. To place 24/7 coverage on just these units alone would require at a minimum 66 inspectors assuming the inspectors worked no more than a 12-hour day. A work schedule would have to be developed to allow these inspectors off time from their jobs. A normal offshore work schedule for many offshore personnel is a 7 days on and 7 days off schedule. This would translate to a work force of 132 Inspectors just to cover these 33 deepwater drilling units alone. This would represent approximately a 100% increase in the current inspection force just to provide coverage for these 33 units. A plan of only 1 inspector for a 24 hr. day would certainly be problematic in terms of issues that could arise in working excessive hours or other issues related to overtime and how this would impact other MMS salary cap considerations related to pay scales, etc.

One variation to the scenario in the preceding paragraph would be to cluster one or more inspectors to a certain area where-in they would cover more than one rig at a time. This could potentially mean less Inspectors than the scenario just described, but the helicopter transportation needs would be greater in terms of moving them about to observe certain critical operations as they occur.

Prior to the moratorium there were an additional 58 rigs working in the GOMR. These include platform and jack-ups units conducting drilling, completion, workover, or abandonment activities. All of these units at a minimum require monthly inspections based on our current inspection practices. Additionally there are more than 3500 platforms/structures across the GOM that require annual inspections.

Because offshore rig activity can be cyclic in nature, trying to staff up to a certain level of rig activity certainly has downsides in terms of maintaining a staff that is not too large in lean times and not too small during active periods. Increasing staffing by 100%, for example, would also represent a formidable challenge in terms of not only the time it takes to select quality candidates, but the additional time it will take to conduct on-the-job training and knowledge of all MMS inspection protocols.

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For all of the reasons cited above, an alternative approach is recommended as described below.

Alternative inspection approach

One alternative inspection approach that would result in increased inspection presence offshore would be to identify those types of activities representing the greatest operational risks. In identifying these types of activities, we could require the operator to give MMS sufficient advanced notice so that we could direct Inspectors and/or Engineers to be at these locations to observe, witness, and inspect these activities. In some cases, the nature and duration of these activities could result in more than 1 day at a site, but this would represent a more manageable situation compared to a 24/7 requirement. This approach would also eliminate the need to develop schedules (such as 7 and 7) that would call for many more personnel. This type of approach would also tend to lessen the additional amount of aircraft that would be required compared to the type of numbers of aircraft to efficiently provide for 24/7 coverage.

A review has been made of all Potential Incident of Non-compliance (PINC's) associated with rig activity and also a review for all PINC's associated with offshore production operations. As a result of this review we have identified those PINC's and their associated activities that represent the higher risks or concerns.

Summary of highest risk **rig** activities and associated PINC's

The below offshore activities would be visited more frequently for those rig operations judged to be of highest risk. Risk factors to be evaluated will include the following:

- Operations with subsea stacks would generally represent higher risk vs. operations with surface stacks.
- Complexity of operations—floaters generally have more complexity vs. operations on jack-ups and fixed platforms.
- Distance from shore—impacts ability to rescue personnel in time of a disaster as well as environmental impacts to coastlines, etc.
- Drilling locations in environmentally sensitive areas
- Exploratory vs. development wells
- Considerations based on worst case scenarios for any given drilling operation—for example, once a hydrocarbon bearing zone is penetrated, what is the worst case scenario (production volume) if there was a complete loss of well control.
- Others?

Activities (in the case of drilling and other rig operations, **the single most important function is for the BOP, diverter, and accumulator equipment to test and function properly**. Consequently, MMS would require the operators to provide sufficient advanced notice of BOP and related equipment tests, start-ups, etc. so we can potentially be present at the rig to witness these operations. The following list of PINCS list the items that apply to these tests:

Subsea BOP Systems (MOST CRITICAL):

D-240- Are there at least four remote-controlled, hydraulic operated BOP's at least two equipped with pipe rams, one blind shear and an annular
D-241- Accumulator to provide fast closure in case of a loss of power.
D-242- Does the BOP include operable dual-pod control systems.
D-250- BOP test low pressure prior to conducting high pressure test.
D-251- Pressure tested to a pressure equal to the approved APD test pressure.
D-257- Variable-bore pipe rams pressure tested against the largest and smallest sizes of pipes.
D-269- Blind-shear rams tested during a stump test.

Subsea (stump) BOP Test (MOST CRITICAL):
D-281- Subsea BOP stump tested at the surface with water to the rated working pressure.
D-282- Subsea annular-type BOP stump pressure tested at the surface with water to 70 percent of the rated working pressure.
D-283- Subsea BOP stack pressure tested after installation.

List of all PINCs that would be covered in initial subsea and surface BOP tests:

D-203 – Automatic backup accumulator-charging system
D-204- One remote BOP remote control station.
D-205- BOP stack has separate kill and choke lines
D-207- Choke and kill line equipped with two full opening valves.
D-209- Choke manifold components have a rated working pressure at least as great as the rated working pressure.
D-212- Upstream choke manifold have pressure ratings at least as great as the rated working pressure on the ram type BOP.
D-213- Is the wellhead assembly with the rated working pressure that exceeds MASP installed.
D-221- locking devices on rams installed.
D-223- Choke line installed above the bottom ram.
D-224- Is a kill line installed on the BOP stack.

Surface BOP Test:
D-270- BOP system pressure tested when installed.
D-271- BOP system tested with water.
D-272- Is the annular-type BOP pressure tested with water to 70 percent of its rated working pressure.

Critical PINCs for Diverter Systems:
D-300- The drilling unit equipped with a diverter while drilling a surface hole.

D-301- Is the diverter system equipped with full opening remote controlled valves in the flow and vent lines.
D-302- Are the sealing element, diverter lines, and diverter control systems and flow line tested when installed.
D-305- Are all right-angled turns targeted.
D-307- Is the diverter anchored and supported to prevent whipping and vibration.
D-311- Are branch lines installed have downwind diversion capabilities.

All the other PINCs can be documented by using charts and can be inspected when doing the monthly inspection.

Summary of highest risk **production** activities and associated PINC's

The below activities would be visited more frequently for those production facilities judged to be of highest risk. Risk factors to be evaluated will include the following:

- production volumes that are processed and/or production volumes that flow across these facilities
- distance from shore
- complexity of operations,
- risk factors related to fixed vs. floating structures
- Others?

Activities (these are not listed in order of importance)

1) Witnessing of pipeline installations due to reactivation after being out of service for more than 1 year could require onsite personnel to review records and approved procedures that would require prior notification. An 8 hour hydro-static test is required as outlined in the regulations. PINC-L-124

2) Return to service pipeline installations. The same would hold true for pipelines that would be returned to service after repairs were made due to upgrades/modifications. This would require pre-notification to arrange for on-site witnessing of hydro- static testing and review approved procedures. A 2 hour test would be required. PINC-L125

3) Witnessing of boarding shut down valves as approved in the DOWP for actuation and leakage (0 leakage) verification onsite. PINC-109

4) Onsite witnessing for no natural flow (no-flow test) to verify if the required sub-surface safety device can be removed by request for a departure (PINC-260).

5) Testing SCSSV's. Is each SCSSV installed in a well tested when installed or reinstalled and at intervals not exceeding 6 months and removed, repaired and reinstalled, or replaced, if it does not operate properly. This is a test that would consume time when the SCSSV is installed in a subsea well. (P-280)

6) Testing SSV/USV's. Is each SSV/USV tested for operation at least each month, with no more than 6 weeks elapsing between tests, and repaired or replaced if found defective (P-307).

7) Checking wellhead configurations. Is each wellhead completion equipped with a minimum of one master valve and an operable SSV or USV, located above the master valve, in the vertical run of the tree (P-412). Additional notes: This is a test that would consume time when installed in a subsea well. Underwater Safety Valves (USVs) are allowed a leakage rate and normally are tested on quarterly bases not to exceed 120 days. Most operators will do a USV and SCSSV test at the same time when 6 month test is due on SCSSV. The test frequency and leakage rates are approved in the DWOP. However, the DWOP may allow for the USV to be located on the horizontal run of the subsea tree.