GulfofMexicoSPU

bp

Macondo Relief Well

MC252 #2

Plug and Abandon Procedure
(for APM)

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1 Plug and Abandon Procedure

1.1 Current Status

The MC252 #2 well was drilled by the Development Driller II (DDII) as a contingency for the primary relief well (MC252 #3, drilled by the DDIII). The well was temporarily abandoned in August 2010. The well never reached the reservoir section, and the 11 ⅞-in liner was never drilled out.

- All hydrocarbon zones have been isolated by cement and proven via cement bond logs during the drilling operation.
- The primary abandonment Plug (#1), which consists of the cemented 11 ⅞-in casing shoe, already has been tested with both weight (15,000 lbs) and pressure (2,800 psi with 13.65 ppg surface Mud Weight (MW)). This was done prior to the temporary abandonment.

1.2 Objective

The objective is to properly secure the Macondo #2 relief well. This will be accomplished by placing cement plugs for zonal isolation.

- Ensure adequate isolation of hydrocarbon bearing zones, per BP and Bureau of Ocean Energy Management (BOEM) requirements.
- Continue to isolate the cased hole, per BOEM requirements, to the mud line.
  - Utilize Halliburton EZSV-B as mechanical barriers in support of cement plugs.
  - Cut and recover approximately 1,600-ft of the 13 ⅝-in casing, prior to spotting Plug #4 and Plug #5.
  - Each of the cement plugs will be weight tested to 15,000 lbs and pressure tested to 1,000 psi. Additionally, Plug #4 will be negatively tested prior to displacing the well to seawater.

Note: All cement and spacer volumes and densities should be confirmed by rig-site engineers prior to job and adjusted if necessary based on final lab tests and modeling.

1.3 Latch Up BOP Stack to #2 Wellhead and Test BOPs

Note: Provide the BOEM 48 hours advance notification of 14 day scheduled BOP testing to allow for witnessing.

Note: Provide the BOEM 72 hours advance notification of BOP stump testing and the initial BOP test on the seafloor to allow for witnessing per BOEM latest guidance document (excerpt below):

Regarding BOP tests

Operators are expected to notify BOEMRE at least 72 hours prior to all BOP stump tests and initial BOP tests on the seafloor to facilitate having a BOEMRE representative present to witness at least one of these tests. If BOEMRE receives appropriate notice and is unable to, or elects not to, witness at least one of the tests due to factors beyond the operator's control (including, for example, weather conditions and transportation availability), the operator may proceed with the test. However, in cases in which BOEMRE does not witness a BOP stump test or initial seafloor test, the operator must provide the results of the test (in either electronic or paper format) to BOEMRE within 72 hours of the test.

1. Prepare to run Blow Out Preventer (BOP) stack and marine riser.
2. Prior to running the BOP stack, stump test ram type BOP to 15,000 psi and annular type BOP to 7,000 psi on 5 7/8-in drill pipe with seawater as per MC252 #2 Application for Permit to Drill (APD) and BOEM regulations. Testing will include:
   - ROV Intervention test
   - Deadman (autoshear) test
   - Emergency Disconnect System (EDS) test
3. Run BOP and marine riser.

Note: Pressure test choke and kill line to 250 psi (low) and 10,000 psi (high) for 5 minutes. Pressure test rigid conduit and boost line to 5,000 psi for 5 minutes or as per rig-specific guidelines.

4. Position the rig over the wellhead and latch up.
5. Perform "Low Pressure" Connector test. Close upper Blind Shear Ram (BSR) and test connector against BSR and RTTS packer to 1,000 psi for 5 minutes.

Note: The 13 5/8-in casing and BSRs (lower and upper) will be tested to 2,800 psi in a later step.

6. Conduct Deadman test. Refer to Transocean's procedures.
7. Use Remotely Operated Vehicle (ROV) to close BSR.
8. Trip in with BOP isolation test tool on 5 7/8-in pipe per Dril-Quip procedures.

9. Land BOP test tool in wellhead and test wellhead connector to 250 psi (low) and 6,500 psi (high) with seawater per the original MC252 #2 APD. A successful BOP test (for all BOP tests) will be the output of the Digital BOP Testing Criteria as stated in the APD.

Note: The 13 5/8-in wear bushing is already in place in the wellhead (ran 5 July 2010).

10. Test annular preventers to 250 psi (low) and 5,000 psi (high) as per APD with seawater.

Note: Annulars may be tested to 6,500 psi to facilitate testing of all valves and lines.

11. Test all remaining equipment per approved APD requirements

Note: BOEM casing test will be performed against BSRs after displacing well to mud and recovering the RTTS and drillpipe.

12. POOH and lay down BOP test tool.

1.4 Latch On and Pull RTTS and Drill Pipe

Note: The well was temporarily abandoned with a 13 5/8-in RTTS at 5,754-ft MD, with 100,000 lbs of weight below it (bottom of tailpipe +/-9,735-ft).

1. RIH with 5 7/8-in DP and RTTS retrieval tool to approximately 5,745-ft (~10-ft above RTTS) and displace the well to 13.65 ppg Synthetic Oil Based Mud (SOBM).
2. Trip in Hole (TIH) to RTTS. Engage packer per Halliburton Representative. Close annular and reduce operating pressure if required prior to unseating packer. Notify Houston if pressure exists below packer.

Note: Per BOEM request, Houston will consult BOEM if pressure is found below the packer.

Note: If pressure is noted below RTTS, a procedure will be provided to bleed the pressure off in stages to determine whether it is trapped pressure or connected to a source.

3. Establish circulation and circulate bottoms up through choke line prior to pulling the RTTS. Check for flow for 15 minutes. If no flow, open annular. Pump while POOH to just below the BOP stack to mitigate swabbing. Check for flow for 15 minutes prior to pulling the RTTS through the stack.
4. Continue POOH with RTTS and 5 7/8-in DP.
5. Once RTTS is out of the hole, close BSRs and test casing and BSRs to 250 psi (low) and 2,800 psi (high) per approved APD. The test against one set of BSRs will be held for 30 minutes (standard BOEM casing test), with a successful test meeting the following criteria:
   - For a successful casing test, the BP guidelines (GP 10-45 5c: Working with Pressure) must be met, and states the following: A pressure test shall be carried out for a minimum undisturbed 30-minute monitoring

period. An acceptable test is defined as stable or decreasing pressure fall off less than 5 psi/minute for the final 15 minutes.

- MMS regulations (CFR30 250.423) must also be met for a successful casing test, and states a failure as occurring *if pressure declines more than 10 percent in a 30-minute test or if there is another indication of a leak.*

Note: The test against the second set of BSRs may be held for a 5-minute straight line as per Digital BOP testing criteria as stated in the APD.

1.5 P&A Plug #1

The primary abandonment plug, which consists of the cemented 11 ⅞-in casing shoe, already has been tested with both weight (15,000 lbs) and pressure (2,800 psi with 13.65 ppg surface MW). This was done prior to the temporary abandonment.

This section will not require any steps unless pressure is noted below RTTS and another plug is required on bottom. This will be addressed in an Ops Note if needed.

1.6 P&A Plug #2 – Set EZSV-B above 11 ⅞-in Liner Top, Place Balanced Plug

1.6.1 Set EZSV-B on Wireline at 13,400-ft MD

1. Rig up the Halliburton wireline unit.
2. Make up a 12.0-in gauge ring with junk basket and Casing Collar Locator (CCL). Run in the hole to approximately ten feet below the first connection after 13,400-ft MD per Halliburton instructions. Do not exceed 13,450-ft MD (top of liner is 13,463-ft MD). POOH and rig down the assembly.
   - If the gauge ring cannot be run to the desired depth, POOH with wire line and prepare to make a cleanout run with scraper assembly.
3. Make up a 13 5/8-in Halliburton EZSV-B, with Down-hole Power Unit (DPU) and CCL and RIH on wireline.
4. Set the EZSV-B at +/-13,400-ft MD, avoiding connections, per Halliburton procedure.
5. POOH with wireline and Rig Down (RD) same.

1.6.2 Place Balanced Plug #2

1. Pick up ~500 feet of 3½-in drill pipe for cementing stinger assembly with diverter. RIH on 5 7/8-in drillpipe with ball catcher.
2. Mix and pump spacer and 64 bbls (~360 ft^3) of 16.4 ppg cement per Halliburton cement procedure. Volume based upon ~40% excess to provide a 300-ft cement plug (13,100-13,400-ft MD).

- Rubber wiper balls will be pumped ahead of and behind cement for fluid separation

3. Pull diverter 500-ft above top of cement, drop foam wiper balls and circulate bottoms up.
4. POOH.
5. Pick Up (PU) and Run In Hole (RIH) with mill tooth bit assembly. Tag the cement plug and weight test the plug to 15,000-lbs for 5 minutes. POOH.
6. Pressure test Plug #2 to 1000 psi per BP and BOEM requirements.
   - Acceptance criteria: no more than 10 percent pressure drop in 15 minutes.

1.7 Annular Squeeze (Abandonment Plug #3) – Set EZSV-B, Perforate and Squeeze

1.7.1 Isolate 13-5/8-in x 16-in Casing Annulus

1. RIH to +/- 6,920-ft with TCP guns and Halliburton 13 5/8-in EZSV-B retainer.

Note: The perf gun and charges will be configured to ensure the 22-in casing is not damaged.

2. Set retainer at +/- 6,920-ft MD, and verify it is set properly per Halliburton procedure.
3. Pressure up drill string to ~3,350 psi to fire TCP guns. Hold for one minute, then release the pressure. This is a time-delayed firing head, so the guns will fire in 5-7 minutes even though pressure has been released.
4. Attempt to establish injection rates.
   - Maximum allowable injection pressure is 1,500 psi. This is equivalent to 2.1 ppg over the estimated overburden at the 16-in shoe. The limit is based on the burst rating at the 16-in shoe.

Note: A minimum of 1-2 bpm injection rate is required to proceed with the cement job as planned. If unable to establish injection at a minimum of 1-2 bpm with 1,500 psi injection pressure, consult Houston team. An operational note may be required to modify the squeeze volume or skip to Section 1.8

- The 16-in liner shoe is set at 11,943-ft MD. The top of cement (TOC) in the 13 5/8-in x 16-in annulus has been logged at 12,350-ft MD. There are no permeable zones exposed, and a Formation Integrity Test (FIT) was conducted to a 13.66 ppg downhole equivalent, or approximately 250 psi above hydrostatic (the combined pressure of 13.65 ppg down to ~7,000-ft, and 12.7 ppg below that). It does not appear that the test achieved leak-off.

- Modeling indicates the system will require approximately 4 bbls to pressure up 1,000 psi

5. If able to inject, mix and pump spacer and a minimum of 197 bbls (~1,105 ft^3) of 16.4 ppg cement per Halliburton cementing program. 197 bbls is calculated based on the annular space between 13 5/8-in and 16-in casing strings from 6,920-ft down to the 16-in shoe at 11,943-ft MD, with 0% excess.
6. Pump wiper balls and circulate bottoms up immediately above retainer with 13.65-ppg SMW SOBM.
7. POOH.

1.8 Place Balanced Plug (Stub Plug/Abandonment Plug #4) – Swap Mud, Cut and Pull CSG, Set Balanced Plug

1.8.1 Swap Mud to 12.7 ppg SMW and Pull Wear Bushing

1. Negative test the EZSV-B prior to reducing the mud weight. Follow the General Negative Test Procedure (Attachment 5).
   - Choke line displaced with 24 bbls (1,544-ft) of 6.8 ppg base oil, with 13.65 ppg SMW in the hole, will provide ~546 psi differential (which equates to a 12.7 ppg SMW, plus 200 psi additional differential pressure for monitoring purposes).
   - BP and Transocean engineers on site to confirm actual base oil density and all negative test calculations prior to the job, and adjust volumes accordingly.
2. RIH with ~1,600-ft of drillpipe and DrilQuip Multi-Purpose Tool (MPT) to approximately ~50-ft above the EZSV-B. Circulate the well to 12.7 ppg SMW (12.9 ppg Down Hole Mud Weight (DHMW)).
   - This is in preparation of cutting the 13 5/8-in casing, which has 12.7 ppg SMW in the annulus.
   - During displacement, monitor fluid volumes in and out of the wellbore. Ensure the correct pits are being monitored, and limit transfers between other pits.
   - Maintain a high level of awareness during the negative test and the displacement. Be prepared to shut in the well if there are any indications of flow or abnormal pressures.
3. After the displacement, land the MPT in the well head and engage the wear bushing with MPT per DrilQuip representative. Retrieve same.
4. POOH and LD the MPT and the wear bushing.

1.8.2 Pull Seal Assembly

1. PU ~5 stands of 5 7/8-in drill pipe. Make up and run in the hole with the DrilQuip MPT well head seal assembly running/retrieving tool.
2. Retrieve the seal assembly and lock ring per DrilQuip representative.

Note: If unable to retrieve the seal assembly, do not proceed with casing cutting operations. Notify Houston to discuss plan forward.

3. Circulate one bottoms up through the choke line. Flow-check the well, minimally 15 minutes.
   - Per previous steps, the 13 5/8-in x 16-in annulus should be isolated with cement, and as such a static well bore is expected. In the event injection was not possible, the well may be open to a shale below the 16-in shoe. The 16-in liner shoe is set at 11,943-ft MD. The top of cement (TOC) in the 13 5/8-in x 16-in annulus has been logged at 12,350-ft MD. There are no permeable zones exposed. The 16-in shoe FIT was 13.66 ppge downhole.
4. POOH and LD MPT with seal assembly.

1.8.3 Cut and Pull Casing

1. MU and RIH with the casing cutter assembly supplied by Smith.
2. Cut the 13 5/8-in casing at approximately 6,820-ft MD, per Smith representative instruction. Confirm the casing cut is complete.

Note: If the first cut fails, move up hole ~100-ft and attempt to cut again. If the second attempt fails, notify Houston and POOH.

3. After a successful cut, flow-check the well, minimally 15 minutes.
4. Once the well is confirmed static, release the spear and pull up hole.
5. Re-engage the casing with the spear in the uppermost joint of 13 5/8-in casing. Space out to minimize the exposure of non-shearables across the BOP stack.
6. Pull out of the hole with the 13 5/8-in casing stub (approximately 1,600-ft length).
7. Once the casing hanger reaches the floor, release the spear and stand back the casing cutter BHA.
8. RU 13 5/8-in casing equipment.
9. Pull the 13 5/8-in casing joints, and lay down or rack back same.

1.8.4 Place Balanced Plug #4 (13 5/8-in Stub Plug), Negative Test, Displace to Seawater

Note: If the annulus squeeze was unsuccessful, an additional plug will be added from the top of the stub plug to the planned base of the surface plug. This will be handled via an Ops Note. It will be set prior to unlatching the BOP stack. The added plug will also eliminate the need for the viscous pill and the CST.

1. Make up a 5 7/8-in cementing diverter sub and ball catcher and RIH with 5 7/8-in drill pipe.
   - No 3 1/2-in stinger will be used for this plug.
2. Conduct 1,000 psi positive pressure test as per BP and BOEM requirements to verify annulus cement job.
   - Acceptance criteria: no more than 10 percent pressure drop in 15 minutes.
3. Mix and pump spacer and 111 bbls (~620 ft^3) of 16.4 ppg cement per Halliburton cement program. Volume based upon 20% excess.
   - Volume based upon 100-ft of 13 5/8-in stump above the EZSV-B and 200-ft inside 22-in casing above the stub.
   - Rubber wiper balls will be pumped between cement and spacer to provide separation of fluids.
4. Slowly pull out of the cement plug at 3-4 min/stand to put the end of the diverter sub 500-ft above the top of cement.
   - The planned top of P&A Plug #4 is 6,620-ft MD.
5. Drop 2 foam wiper balls and circulate bottoms up.
6. POOH.
7. PU and RIH with mill tooth bit assembly (12 1/4-in minimum, 18 1/8-in OD maximum). Tag the cement plug and weight test the plug to 15,000-lbs for 5 minutes.
8. Pressure test Plug #4 to 1,000 psi as per BP and BOEM requirements.
   - Acceptance criteria: no more than 10 percent pressure drop in 15 minutes.
9. POOH to above BOP stack to conduct negative test to seawater equivalent at 5,600-ft per General Negative Test Procedure (Attachment 5).
   - Choke line displaced with 74 bbls (4,720-ft) of 6.8 ppg base oil, with 12.7 ppg SMW in the hole, will provide an 8.55 ppg seawater gradient at 5,600-ft, plus 200 psi additional differential pressure for monitoring purposes.

- BP and Transocean engineers on site to confirm actual base oil density and all negative test calculations prior to the job, and adjust volumes accordingly.

10. After the base oil has been displaced out of the choke line and well monitoring has confirmed that the well is static (both with blind rams closed and with blind rams open), trip in to 5600-ft and displace the well to seawater per standard Transocean procedure (a ram will be closed at all times).
    - During displacement, monitor fluid volumes in and out of the wellbore. Ensure the correct pits are being monitored, and limit transfers between other pits.
    - Maintain a high level of awareness during the negative test and the displacement. Be prepared to shut in the well if there are any indications of flow or abnormal pressures.
11. POOH.
12. Prepare to unlatch BOP stack and pull riser.
13. Unlatch wellhead connector and pull BOP stack to safe transit height. Secure riser and proceed with next step on aux rotary.

1.9 P&A Plug #5 – Set Balanced Surface Plug

1.9.1 Set Abandonment Plug #5

1. RIH with Halliburton CST ball seat and diverter sub on the 5 ⅞-in, XTM57 drill pipe cementing string. No stinger will be required.
2. TIH to depth of 5,600-ft MD. Circulate bottoms up to the wellhead.
3. Deploy the CST to be set at approximately 5,600-ft MD.
    - Insert the Halliburton CST, displacement dart and phenolic ball.
    - Circulate the CST/dart/ball to the end of the work string.
    - Follow Halliburton recommendation regarding displacement rate. Maximum rate in the 5 7/8-in drill pipe with a CST is approximately 6-bbls/min.
    - Slow rate to 1 ½-bbls/min for the last 100 to 200-ft. This facilitates "soft launching" the CST.

4. Mix and pump 153 bbls (~860 ft^3) of 16.4 ppg cement as directed. The volume is based upon ~300-ft of 22-in casing (20.0-in ID) with 30% excess.
    - This will leave the top of cement (TOC) at approximately 5,300-ft MD, or 82 ft below the wellhead.
    - Prior to displacing with seawater, pump 15 bbls of gelled seawater behind the cement.
5. Displace with seawater to balance.
6. Slowly pull out of the cement plug at 3-4 min/stand to put the end of the diverter sub above TOC.
7. Clean drillpipe by circulating seawater and a calcium carbonate/nut plug sweep at max rate.
8. POOH.
9. PU and RIH with mill tooth bit assembly (minimum 12 1/4-in OD, maximum 18 1/8-in OD). Tag the cement plug and weight test the plug to 15,000-lbs for five minutes. POOH.
10. Once surface plug is confirmed, have ROV install wellhead cap.
11. Pull riser and BOP stack.

Attachments

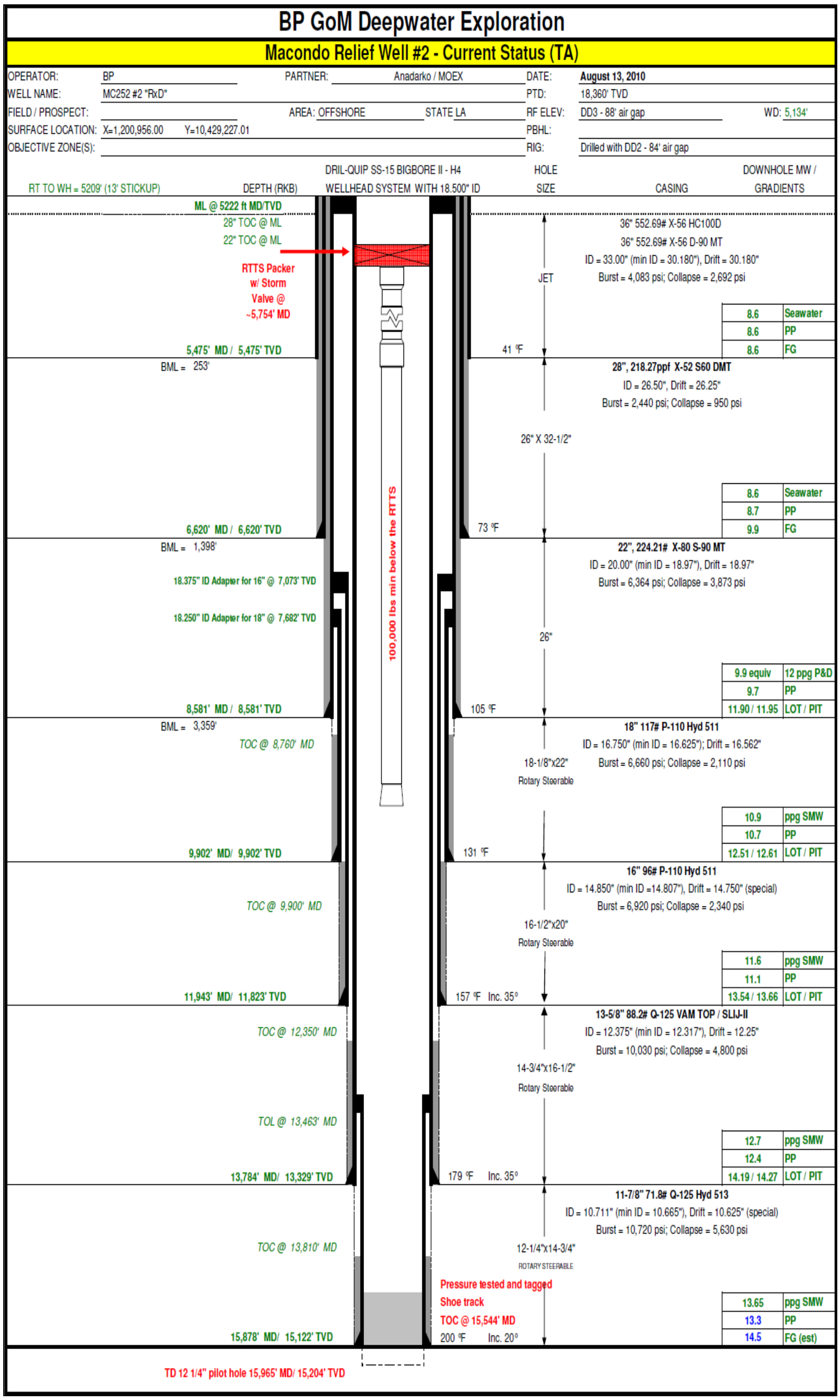
No.	Title
1	BOEM Requirements for BOP Testing
2	Current Wellbore Schematic
3	Proposed Plug & Abandon Schematic
4	Schematic with BOEM Regulation References
5	General Negative Test Procedure
6	MASP Calculation: BP Gulf of Mexico – MMS APD Worksheet

Attachment 1:
BOEM Requirements for BOP Testing

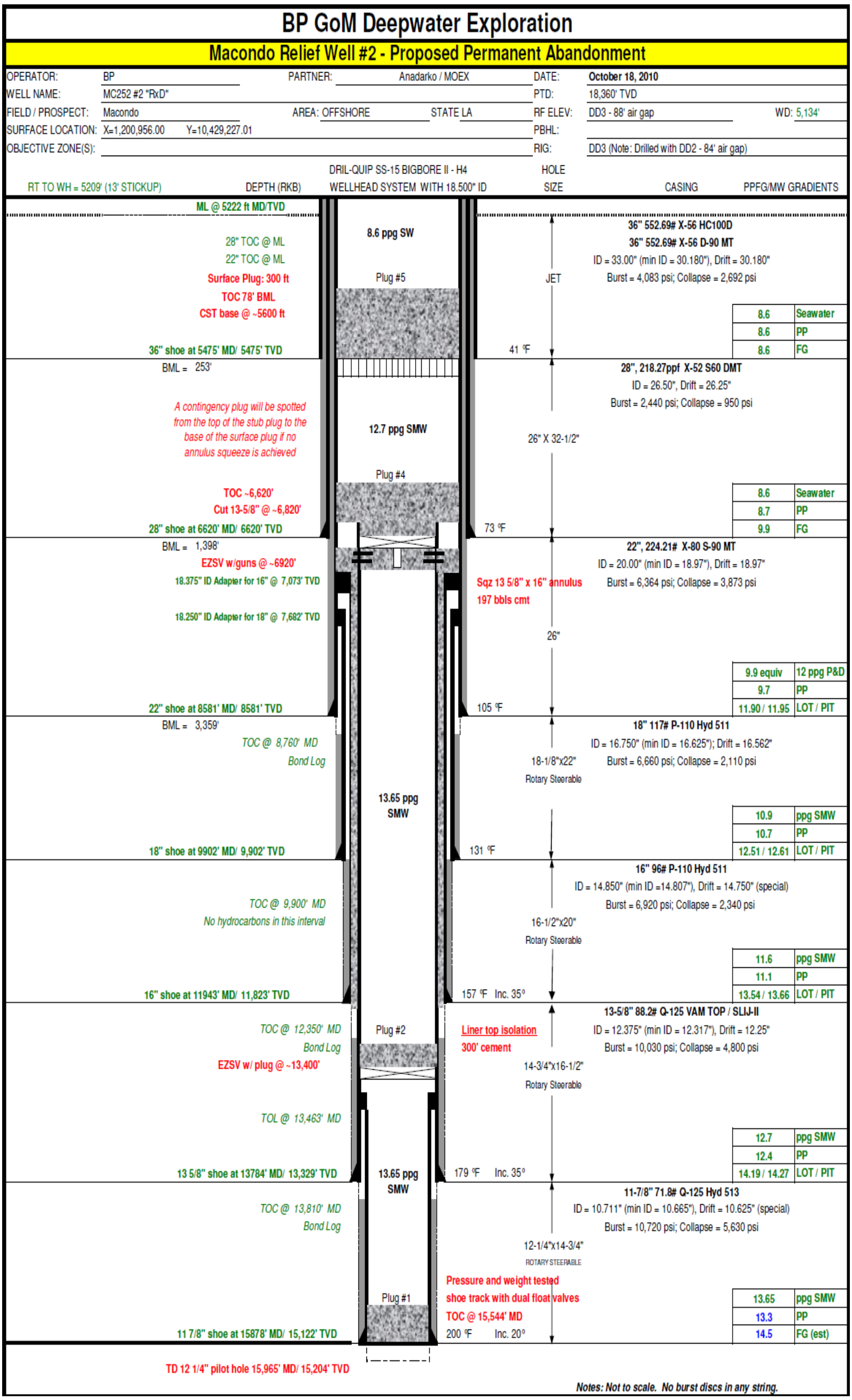
Bureau of Ocean Energy Management (BOEM) requires a Full Function and Pressure Test of all Blow Out Preventer (BOP) components, including choke and kill lines and valves and choke manifold.

- Diverter Function Test
  - Make sure the mud level in the riser is below the diverter vent line outlets. Close diverter in "Normal" Divert mode on Diverter panel MMI. Time packer closure and verify by viewing through rotary. Observe the overboard valves opening.
  - Do not pump through vent/overboard lines. Open the diverter packer and close overboard valves and verify by visual observation.
  - This test will be performed weekly, rotating between the Driller's panel and the Toolpusher's panel on the bridge, and in conjunction with BOP test and weekly function test.
- After running isolation test tool or having used inverted test rams
  - Using the 5 ⅞-in drill pipe that will be run though the BOP stack.
  - Pipe rams tested to 250 psi (low) and 6,500 psi (high).
  - Upper and Lower Annular tested to 250 psi (low) and 5,000 psi (high).
- After retrieving the isolation test tool or without pipe across stack
  - Test Blind Shear Ram (BSR) and casing to 250 psi (low) for 5 minutes and to the equivalent of 2800 psi with 13.65 ppg SMW as per the approved Application for Permit to Drill (APD) psi for 30 minutes.
  - Test second BSR as per the approved APD psi for 5 minutes.
  - Function casing shear rams.

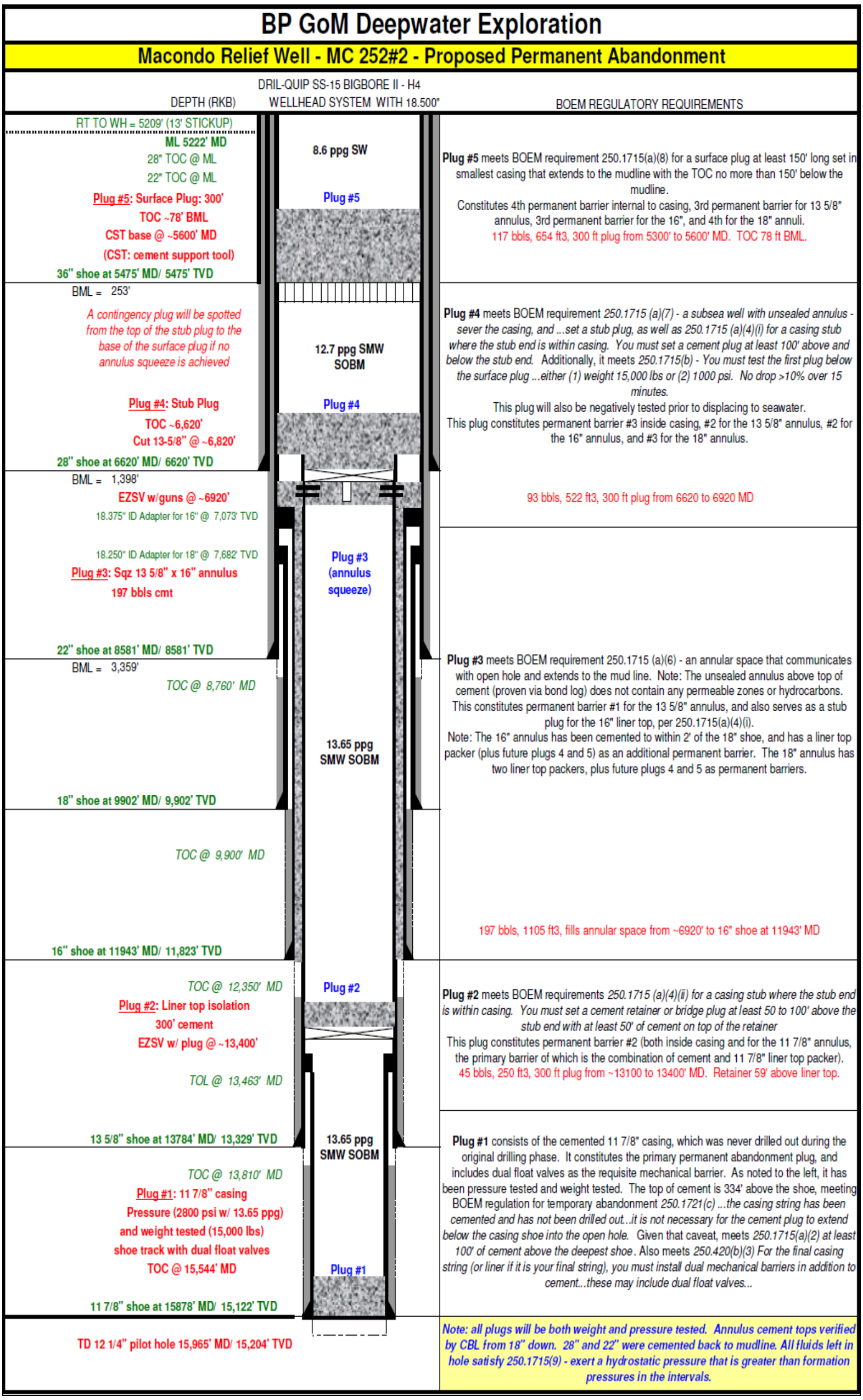
Attachment 2:
Current Wellbore Schematic



Attachment 3:
Proposed Plug & Abandon Schematic



Attachment 4:
Schematic with BOEM Regulation References



Attachment 5:
General Negative Test Procedure

Well Condition Assumptions

- Wellbore is isolated from all flow paths below wellhead by cement, retrievable plug(s), packer(s), etc.
- Well Site Leader, Mud Engineer, and Rig Contractor Representatives have agreed on the riser displacement procedure.
- Blind rams are closed

Perform Negative Test

1. The subsea engineer will open the upper inner and outer choke line valves and upper inner and outer kill line valves.
2. Pump sufficient volume of base oil (6.8 ppg) down the choke line to establish an equivalent wellhead pressure of 200 psi below the desired gradient - take returns up the kill line. Close kill line valves.

Note 1: Utilize base oil to allow displacing to a seawater or lower gradient without displacing all the way to the stack.

Note 2: Pump base oil down the choke line. If the well head seal or downhole isolation is lost, the base oil in the choke line can be recovered / displaced with kill mud weight by circulating a minimum volume from the kill line across the stack.

- Calculate the estimated choke shut-in pressure (choke SIP)
- Choke SIP = (MW-6.8)*0.052*height of base oil column

3. Bleed pressure down on the choke line in steps to 200 psi and monitor on chart.
   - Document the Rig Contractor's acceptable differential pressure from above on the shear rams.

Note: Monitoring a closed system with pressure on the gauge will minimize any gains to the system if the downhole isolation is lost. The pressure on the choke would increase and an influx would still be taken; however, the gain to the system would be restricted by the shut-in well.

4. Monitor the pressure for 15 minutes.

Note: A pressure decrease is anticipated due to temperature effects. Cooling of fluid will cause a small volume decrease, thus a pressure drop may be realized. However, any pressure increases should be fully evaluated for potential isolation failure.

- Monitor riser on trip tank.
- Monitor pressure reading on HPHT sensor on BOP stack.

5. Bleed choke to zero. Open and monitor for flow for 60 minutes.
   - Note that the pressure below the shear rams may be less than a seawater gradient. Ensure this does not exceed acceptable limits set by the Rig Contractor.
6. If flow observed, troubleshoot to determine if the blind shear ram is leaking.
   - If flow is observed and the blind shear rams are holding, the retrievable plug, packer, and/or the subsea wellhead seal assembly should be evaluated. Discuss with Houston and determine forward plan regarding barrier requirements.
7. After a successful negative test, open the lower inner and outer kill line valves. The choke is expected to see the U-tube pressure from the mud in the kill line.
8. Displace the base oil out of the choke line by pumping mud down the lower inner and outer kill line valves and adjusting the choke to take the base oil returns from the upper choke line valves.
9. When the base oil has been recovered monitor below the shear rams with the well monitoring tank and monitor the riser on the trip tank for 15 minutes.
   - Ensure it is possible to visually observe the flow coming into the tank. Do not rely on PVT sensors to determine "no flow" or "flow".
   - The tank should be observed by an experienced crew member and the pit level monitored electronically if possible.
10. Open stack and monitor the riser volume for 15 minutes using the trip tank.

Attachment 6:
MASP Calculation: BP Gulf of Mexico -- MMS APD Worksheet

BP Gulf of Mexico - MMS APD Worksheet

MASP - Frac Gradient Method
The frac pressure at the 16 Liner shoe is:
P @ shoe = 11,819' x 13.6 ppg x 0.052 = 8360 psi

A column of 0.15 psi/ft gas yields:
P @ ML = 8360 - 0.15 x 6601 = 7370 psi
P @ surf = 8360 - 0.15 x 11,819' = 6590 psi

MASP - Bottom Hole Pressure Method
The bottom hole pressure at 13,400' TVD is:
P @ TD = 12370' x 12.7ppg x 0.052 = 8170 psi *(done at TOC, with MW at TD)*

A column of 60% gas & 40% liquid back to surface gives:
P @ surf = 8170 - 0.6 x 12370' x 0.15 psi/ft
- 0.4 x 12370' x 12.7ppg x 0.052 = 3790 psi

Using 60% gas and 40% liquid from ML to surface, the mudline pressure is:
P @ ML = 3790 + 0.6 x 5,218' x 0.15 psi/ft
+ 0.4 x 5,218' x 12.7ppg x 0.052 = 5640 psi

Note: no permeable zones and no HC will be exposed during the P&A operation. Therefore, these numbers are conservative. 4000 psi MASP would be more reasonable without 60% gas assumption