Form 3160-5
(August 2007)

RECEIVED

OCT 18 2011

Farmington Field Office
Bureau of Land Management

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0135
Expires July 30, 2010

SUNDRY NOTICES AND REPORTS ON WELLS
Do not use this form for proposals to drill or to re-enter an Abandoned well Use Form 3160-3 (APD) for such proposals.

5 Lease Serial No
NMNM013688

6 If Indian, Allottee or tribe Name

SUBMIT IN TRIPLICATE – Other instructions on reverse side

7 If Unit or CA/Agreement, Name and/or No.

1 Type of Well
☐ Oil Well ■ Gas Well ☐ Other

8. Well Name and No.
Atlantic LS 1A

2. Name of Operator
BP AMERICA PRODUCTION COMPANY

9. API Well No.
30-045-22877

3a Address
PO BOX 3092 HOUSTON, TX 77253

3b Phone No *(include area code)*
281-366-4081

10 Field and Pool, or Exploratory Area
Blanco Mesaverde

4. Location of Well *(Footage, Sec., T, R., M., or Survey Description)*
1820' FSL & 1100' FEL; SEC 25 T31N R10W NESE

11 County or Parish, State
SAN JUAN, NM

12 CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OR NOTICE, REPORT, OR OTHER DATA

TYPE OF SUBMISSION	TYPE OF ACTION			
■ Notice of Intent	☐ Acidize	☐ Deepen	☐ Production (Start/Resume)	☐ Water shut-Off
☐ Subsequent Report	☐ Alter Casing	☐ Fracture Treat	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	■ Other clarification & correct previous sundry
	☐ Change Plans	☐ Plug and Abandon	☐ Water Disposal	
	☐ Convert to Injection	☐ Plug Back		

BP

13 Describe Proposed or Completed Operation (clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones Attach the Bond under which the work will be performed or provide the Bond No on file with BLM/BIA Required subsequent reports shall be filed within 30 days following completion of the involved operations If the operation results in a multiple completion or recompletion in a new interval, a Form 3160-4 shall be filed once testing has been completed Final Abandonment Notices shall be filed only after all requirements, including reclamation, have been completed, and the operator has determined that the site is ready for final inspection

Please reference sundry filed 09/28/11.

Sept. 2011; Cameron went to the location of **Atlantic A LS 1** and measured the well head. It was found it to be straight. This was not the well with the leaning wellhead issue.

The week of Oct. 10, 2011 Cameron measured the correct well head (Atlantic LS 1A) and found the wellhead is leaning and does need corrective action.

The attached procedure is BP's plan to correct the leaning wellhead, remove the bridge plug over the DK and finish the clean out of the above mentioned well.

RCVD OCT 25 '11

Should you have questions please call Trevor Mcclymont @281-366-1425

OIL CONS. DIV.

DIST. 3

14 I hereby certify that the foregoing is true an dcorrect
Name (Printed/typed)
Cherry Hlava | Title **Regulatory Analyst**

Signature *Cherry Hlava* | Date **10/17/2011**

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved by	Title	Date
Original Signed: Stephen Mason		OCT 19 2011
Conditions of approval, if any, are attached Approval of this notice does not warrant or Certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon	Office	

Title 18 U S C Section 1001 and Title 43 U S C Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter witin its jurisdiction.

NMOCD

BP - San Juan Wellwork Procedure

Atlantic LS 1A

General Information:

Job Objective:	Clean Out	**Date:**	12-29-2010
Project #:		**Total AFE Amount:**	$120,000

Contact:

Intervention Engineer:	Trevor McClymont	p. (281) 366-1425	c. (701) 770-6879
Base Management Engr:	Mike Morgan	p. (281) 366-5721	c.
Production Team Leader	Bob Wiley	p. (281) 366-4641	c.
Intervention Engineer	Jim McKamie	p. (281) 366-5401	c. (281)-660-4946
Intervention Engineer	David Wages	p. (281) 366-7929	c. (406)-231-4679

Well Information:		**Production Data:**	
API Number:	30-045-22877	**Artificial Lift Type**	Plunger
Present Status	Producing	**Current Production Rates**	
PBTD	6,052'	**Gas (mcfd)**	0 mcfd
Surface Location:	Unit I - Sec 25 - T31N - R10W	**Oil/Cond (bpd)**	0 bpd
GPS Coordinates:	lat 36.8674 long 107.83129	**Water (bpd)**	0 bpd
County	San Juan	**Expected Production Rates**	195 mcfd
State	New Mexico	**Compressed (Y\N)**	Yes
Lateral/Run	B-3 Lateral	**Flowing Pressures (psig)**	
Well FLAC:		**Tubing**	140 psig
Lease FLAC:		**Casing**	140 psig
Meter #:	90553	**Line**	92 psig
BP WI:	75.0%	**Shut-in Pressures**	
Cost Center:	1000260695	**Tubing**	140 psig
Reg Approval Req'd:	No	**Casing**	140 psig
Partner Approval Req'd	Yes	**Bottom hole**	626 psig
Landowner Approval Req'd	No	**MASP**	550 psig
Restrictions:	None	**CO_2%**	1.8%
Additional Approvals	No	**H_2S (ppm)**	0 ppm - No History
Compliance/Issues	None	**Area Classification:**	LCO

Recommended By: ______________________

Input From: ______________________

Approved By: ______________________

Policy Reminder
Any changes to the written procedure requires an approved MoC
MoC (except BoD/SoR) approvals during execution have been delegated to the OTL

Basic Job Procedure:

1. Pull tubing
2. Cleanout the well, if fill is found
3. Run tubing
4. Return the well to production

Well History:

Spud date 10/1978

Well service 6/2011 - Rig moved out to location on 6-29-2011 to perform a clean out. After NU the BOPs, the crew noticed the wellhead was leaning (reports indicate wellhead was a bubble off on a level). E-line was ran in the hole and tagged fill at 5904' GL. The crew TOH with tubing and made a bit and scraper run. After the scraper run, the WSL noticed the wellhead leaning worse. Decision was made to secure well and RD to evaluate wellhead change.

Completion Information

Casing - 7", 23#, K-55 set at 3811

Liner - 4-1/2" 11.6# K-55. from 3628 - 6069'

Perforations-

Mesa Verde interval - 4932 - 6039 (gross)

Tubing - No tubing in the well at this time

Accessories - a CIBP has been set inside the 4-1/2" casing @ 4900'

Workover Specifics

Cleanout fill to PBTD (6052')

Desired Landing depth - 5990' +/-

Tubing Design

Please note the suggested assembly as follows (bottoms up):

- MULE SHOE, 2.375"
- "F" NIPPLE, 2.375 OD, 1.780 ID(with plug pre-installed)
- PUP JOINT 2.375" (if needed for space out)
- TUBING, 2.375, 4.7#, J-55, EUE

Additional Information

1. The wellhead on this well is leaning. When a level is placed on the tubing or casing spool, the level shows a full bubble off.
2. Cameron ID the wellhead and saw no signs of immediate damage on the casing or wellhead
3. The well is secured with a CIBP at 4900' and full opening frac valve on top.

Safety and Operational Details:

ALL work shall comply with DWOP E&P Defined Operating Practice.

All pressure tests will be done to 200-300psi low and 750psi high. Every pressure test will be held of a minimum of 5 minutes and recorded in open wells

1. Standard Site Preparations

1.1. Perform pre-rig site inspection. Per Applicable documents and/or checklists

1. Size of Location	6. Wash (dikes requirements)	11. Landowner Issues
2. Gas Taps, (notify land owners)	7. Bird nesting	12. Protection Barriers Needed
3. Other Wells	8. H_2S	13. Critical Location
4. Other Operators	9. Wetlands	14. Anchors
5. Production Equipment	10. Location of Pits	15. ID Wellhead

1.2. Work with OC through CoW and w/P&S to develop a plan to move or temporarily relocate equipment that prohibits well servicing objectives.

1.3. Perform a second site visit after lines are marked to ensure all lines locations are clearly marked and that Planning & Scheduling has stripped equipment and set surface barricades as needed. Check anchors for certification date and use.

1.4. Have wellhead service company check out wellhead to identify wellhead components, lock-down pins are fully engaged and functional, pressure test hanger seals to specified high and low pressures, check and lubricate casing valves, individually work each flange nut and stud, and replace any corroded bolts and or nuts in preparation for breaking containment.

Note: If any problems are encountered, any wellhead equipment does not function with ease, or if any problems are encountered outside of normal operations then the equipment will be repaired when the rig is on location.

1.5. If the databases indicate H2S is present then check for H2S on tubing and all casing annuli. If excessive H2S is present then notify Well Intervention Engineer (WIE) and Well Intervention Operations Superintendent (WIOS).

1.6. Complete Handover Documentation between Production Operations and Functional Wells Team.

1.7. Check and record shut in casing pressure (SICP), shut in tubing pressure (SITP), intermediate casing pressure (SIICP), Bradenhead pressures (SIBH), and or flowing tubing pressures (FTP) and flowing casing pressures (FCP) in Open Wells daily.

1.8. If SIICP or SIBH exist then notify the Well Intervention Engineer (WIE). Notify WIE if water or gas flow is observed from any annulus.

2. Verify Barrier

NOTE: there is no tubing in the well at this time. There is a CIBP at 4900' and the hole is full of fluid.

2.1. There must be a minimum of 1 mechanical pressure barriers in tubing in order to break containment as per **SJ-SOP-WI-BKCNT-Rev01**. Barrier testing shall conform with **DWOP, NAG-GP 10-36-1**, and **SJ-SOP-WI-BKCNT-Rev01**.

2.2. Verify the CIBP at 4900' is holding by bleeding off any pressure on the wellbore

NOTE: a gauge was installed on the top of the frac valve. Check for pressure.. Open valve to bleed off any pressure. Close valve and monitor for 5 minutes. If no pressure is seen, this would indicate the plug is holding

3. MI Service Unit

3.1. MI Service Unit.

3.2. Confirm integrity of casing valves by performing a negative test. Remove flowline piping.

3.3. Install second working and tested casing valve. If possible, negative test the valve with casing pressure.

3.4. Install diversion lines from casing valves to flow back tank.

3.5. Release pressure from tubing x casing annulus by opening casing valves and flowing well to flowback tank.

3.6. If plugs are installed and have been successfully tested and passed, then bleed down tubing pressure.

3.7. RU rig.

3.8. Replace any corroded bolts and/or nuts, or any wellhead components identified in a previous inspection (step 1.4) prior to breaking containment.

3.9. Using **SJ-SOP-WI-BKCNT-Rev01 sec 7.1**
- If stabilized flowing casing pressure is above 10 psi then kill the well by pumping inhibited (2% KCl equivalent) water down casing.
- If stabilized flowing casing pressure is below 10 psi then proceed with breaking containment.
- If lock down pins are not installed or not on the wellhead then flow well down to flowback tank until stabilized flowing casing pressure is at 0 psi and well is dead.

4. <u>ND WH</u>

4.1. If the downhole barrier was successfully negative tested then ND tree to tubing hanger, install two-way check in hanger, and move to **<u>NU BOPE.</u>**

4.2. If the downhole barrier will not test then RU wellhead lubricator to the tree then test lubricator to pressures specified in the Well Specific Procedure.

4.3. Install two way check in back pressure threads in hanger. If unable to install two way check then use **<u>Kill Well Contingency.</u>**

4.4. Nipple down tree to tubing hanger.

4.5. If a two way check has not been installed, install a H-prep sub with TWC in hanger threads for pressure testing BOPEs.

5. <u>NU BOPE</u>

5.1. NU San Juan BOPE using attached BOPE Configuration. Rams will be sized for the tubing in the well.

5.2. Function test and pressure test BOPEs to pressures specified in the Well Specific Procedure. Perform accumulator test. Record in Open Wells.

5.3. Monitor flowing casing pressure with gauge (with casing flowing to flow back tank) throughout workover to comply with **SJ Underbalanced Tripping Practice.**

6. <u>Set Additional Mechanical Barrier</u>

6.1. MU BHA to set a 2nd mechanical barrier in the 4-1/2" casing:
- ~tailpipe as necessary to set barrier
- Mechanical barrier (model G RBP or similar)
- Barrier setting tool
- 2-3/8" workstring as necessary

6.2. Set barrier @ +/-100'

6.3. POH w/ workstring and setting tool

6.4. Close return line and blind rams, PT RBP to 250 psi low and 750 high for 5 min each, chart test and record volume of fluid pumped.

6.5. ND BOPs

7. **Change out Wellhead**

NOTE: This is a supplement to Cameron's wellhead changeout procedure.

7.1. Components to be installed:
- Casing Head: 11" 3M X 9-5/8" SOW
- Tubing Head: 11" 3M X 7-1/16" 5M W/ 2-1/16" 5M SSO'S.

  NOTE: The new wellhead configuration can be found at the back of this document under **New Wellhead Configuration**

1. RU Pump and lines to pressure test down the 7" x 9-5/8" annulus.
2. Pressure test down the Bradenhead to 250 psi low for 5 min, chart test and record the amount of test fluid pumped.
3. Release pressure and RD lines.
4. Ensure the ground around the wellhead is excavated.

Note: Follow BP's ground disturbance policies

Remove Old wellhead:

5. RI w/ a spear to pull tension on the 7" casing
   - Must pull enough tension to release all loads on 7" casing hanger
   - Max 7" string weight: 87,653# Max Pull: 88,000#
6. Attempt to remove casing hanger, if unable to remove casing hanger at this point, we will have to make two cuts in the 9-5/8" casing in order to drop the casing head.
7. Cut off 9-5/8" Casing just below old Casing Head using Mechanical Cutter (Wachs' Low Clearance Casing Cutter). If the casing hanger was removed, release tension in 7" casing, POH w/ spear. Continue to step 12.
8. Make second cut in 9-5/8" casing approximately 3" below first cut.
9. Cut the 3" section of 9-5/8" casing vertically with a saw so that it can be removed to allow the Casing Head to drop and unload the 7" Casing Slips.
10. Remove the 7" Casing Slips
11. Strip Casing Head Housing off over 7" Casing Stub.
12. Prepare 9-5/8 Casing stub for installation of New Casing Head Housing. Allow at least 17-3/4" of 7" Casing stub above top of 9-5/8" Casing.

Install Casing Head

13. Examine the Casing Head. Verify the following:
    - bore is clean and free of debris
    - ring groove and casing hanger seal area are clean and undamaged
    - all peripheral equipment is intact and undamaged
14. Remove the pipe plug from the test port located near the bottom of the Casing Head.
15. Align the Casing Head above the casing stub orienting the outlets to be compatible with drilling equipment.
16. Carefully lower the Casing Head over the casing stub.
17. Level the Casing Head, weld it to the casing.

NOTE: The weld should be a fillet-type with welds no less than the wall thickness of the casing. Weld legs of 1/2" to 5/8" are adequate for most jobs.

Hang off Casing

18. Examine the Casing Hanger. Verify the following:
    - the packoff rubber is in good condition
    - all screws are in place and intact
    - bore and threads are clean and in good condition
    - slips are intact, clean, and undamaged
    - seal element is not compressed beyond the OD of the Hanger
19. Remove the latch screw to open the Hanger.

20. Place two boards against the casing to support the Hanger.
21. Wrap the Hanger around the casing and replace the latch screws.
22. Verify that the seal element is not compressed beyond the OD of the Hanger. If it is, loosen the cap screws in the top of the Hanger. The seal MUST NOT BE COMPRESSED prior to slacking off casing weight onto the Hanger.
23. Remove the slip retaining screws.
24. Grease the Hanger body and packoff rubber.
25. Remove the boards and carefully lower the Hanger into the Casing Spool, using a cat-line to center the casing, if necessary.
26. When the Hanger is down, pull tension on the casing to the desired hanging weight + 1-1/2" then slack off.
27. Tighten the cap screws in the top of the Hanger in an alternating cross fashion to the recommended torque listed in the Cap Screw Torque Chart.
28. Final cut the casing at 4-1/4" ±1/8" above the top of the Casing Head flange using a mechanical cutter. Place a 3/8" x 3/16" bevel on the casing stub and remove all burrs and sharp edges.

Install Tubing Head

29. Examine the Tubing Spool. Verify the following:
    - bore is clean and free of debris
    - 'NX' Bushing is installed, P seal is properly installed and undamaged
    - ring grooves and seal areas are clean and undamaged
    - peripheral equipment is intact and undamaged
30. Lubricate the ID of the P seals and the OD of the casing stub with light oil or grease.
31. Install a new Ring Gasket into the ring groove of the Adapter Flange.
32. Lift and suspend the Tubing Spool over the casing stub, ensuring it is level.
33. Carefully lower the Tubing Spool over the casing stub until it lands on the ring gasket.
34. Tighten the connection using the studs and nuts of the Adapter Flange in alternating cross fashion to the torque referenced in the chart in the back of this manual.

Energize the P Seal

35. Locate the port on the bottom flange of the Tubing Spool for injecting plastic packing into the P seal and remove the pipe plug.
36. Install a plastic injection gun into the port and inject plastic.
37. Continue to inject plastic to 2,400psi (this pressure is subject to change as casing integrity deems necessary).
38. Hold and monitor injection pressure until it has stabilized.
39. Once the injection pressure has stabilized, carefully bleed off injection pressure and remove injection gun.
40. Replace the pipe plug into the open port.

Test the Connection

41. Install a test pump to the port for testing the connection and inject test fluid to either 2,400psi.
42. Hold and monitor test pressure for fifteen minutes.
43. Once a satisfactory test is achieved, carefully bleed off test pressure and remove the test pump.
44. Reinstall the fitting.

    Torque Values:
    - 1-3/8" bolts: 1396 ft*lb
    - 1-1/4" bolts: 747 ft*lb
    - 7/8" bolts: 347 ft*lb

7.2. NU BOPs to new tubing flange per BOP diagram. BOP pipe rams should be sized for 2-3/8" tubing.

8. **Mill Up CIBP**

8.1. MU the following BHA to mill up CIBP at 4900

- Mill for 4-1/2" 11.6# casing
- Bit sub
- Tubing Float
- 6 3-1/8" Drill Collars
- Cross over from 3-1/8 DC to 2-3/8" Workstring
- 2-3/8" workstring to surface

8.2. RIH to CIBP at 4900'

8.3. Begin milling on the CIBP. Recommended milling speed: 120 rpm
NOTE: This is only the *recommended* milling speed and is based on a crushed carbide mill. An insert mill will require 1.5 times the milling sped. Follow guidelines from tool hand based on mill used

8.4. Once CIBP has been milled up, PU additional joints of 2-3/8" tubing and push any remaining pieces of the CIBP to bottom.

9. **Clean Out Wellbore**

NOTE: at this point the WSL may elect to use existing milling BHA for cleanout or POOH with workstring and install a cleanout BHA as specified in Clean Out Contingency

9.1. A cleanout will be performed at this time if:

- Fill is found above cleanout depth specified in Well Specific Procedure
- A chemical treatment was performed
- Agreed on with WIE

9.2. Clean out wellbore using **Clean Out Contingency** and any WIE recommendations located on Well Specific Procedure.

10. **TIH w/ Completion string**

10.1. Tally tubing if not tallied earlier in job. Tally replacement joints

10.2. MU BHA as specified in Well Specific Procedure.

10.3. TIH with tubing to depth specified in Well Specific Procedure

10.4. Load tubing with sufficient water to overcome BHP & test to 500 psi. If unable to test tubing contact WIE for testing options.

10.5. MU redressed tubing hanger with TWC pre-installed, if possible, and lifting pup.

10.6. Land tubing at depth stated in Well Specific Procedure. Remove lifting sub.

10.7. ND BOPE to tubing hanger flange. NU tree.

10.8. Test tree and wellhead connections to specified pressures.

10.9. If wellhead is equipped with test ports, test well head seals to rated working pressure.

11. **Return Well to Production**

11.1. RU Slickline to top of tree referring to **NAG-NOP-SL01.**

11.2. Pressure test SL lubricator to pressures specified in the Well Specific Procedure.

11.3. RIH and pull TWC from tubing hanger, if installed.

11.4. RIH with appropriate tools to equalize and remove plugs in profile nipples. POH.

11.5. If necessary, RIH with appropriate sized broach for tubing to profile nipple (WSL discretion). POH.

11.6. RD SL.

11.7. If well will not flow, discuss option to swab well with rig with WIE. If the decision is made to swab in well with rig, then RU to swab well in following **Swab Contingency.**

11.8. Flow test well until there is stable FTP and FCP. Choke as necessary.

12. Install Plunger Stop, if required

12.1. RU Slickline to top of tree referring to **NAG-NOP-SL01.**

12.2. Pressure test SL lubricator to pressures specified in the Well Specific Procedure.

12.3. RIH and set a plunger stop above/in profile nipple. POH

12.4. RD SL.

13. Return Well to Production

13.1. If Air package used for circulation, run O2 test prior to handing over to Production Operations.

13.2. RD and release all equipment. Remove all LOTO equipment.

13.3. Follow CoW procedures to return well back to production.

13.4. Complete Hand over document between functional Wells Team and Production Operations

13.5. Ensure all well work details and wellbore equipment is entered in 'OPEN WELLS".

Contingency Section

Kill Well Contingency

This contingency will be used if no mechanical barriers can be set in the well after consulting with the WIE and the WIOS.

1. The well will be killed using **SJ-SOP-WI-BKCNT-Rev01**, section 7.4.
2. RU pump and hard lines configured to pump down casing.
3. Pressure test pump and lines to pressures specified in the Well Specific Procedure.
4. Blow down well, bleeding down casing pressure to zero or as low as possible.
5. Pump sufficient kill fluid down casing.

Note: Have as much kill fluid on location as needed to keep well controlled and Iron Sulfide (FeS) on tubing wet while TOH.

Swab Contingency

1. RU to swab using **NAG-NOP-Swab**.
2. RIH w/ swabbing tool mandrel and undersized cups taking a "bite" of fluid per table below:

Tbg OD (in)	Tbg ID (in)	Tbg Capacity (bbls/1000 ft)	Fluid Gradient (psi/ft)	Swab "bite" (ft)	Weight (lbs)
1	0.782	0.59	0.433	6534	1360
1.315	1.049	1.07	0.433	3620	1360
1.66	1.38	1.85	0.433	2095	1360
1.9	1.61	2.52	0.433	1532	1360
2.063	1.751	2.98	0.433	1300	1360
2 375	1.995	3.87	0.433	1000	1360
2 875	2.441	5.79	0.433	670	1360
3.5	2.995	8.71	0.433	444	1360

NOTE: Do not take too large of a bite to create a heavy load on the wireline or a large pressure surge on the formation which may cause sand / fines production.

3. Continue swabbing to minimum tubing ID restriction (or EOT) or until well unloads.
4. Convert to larger cups or more cups as necessary to recover fluid from well.
5. Swab well and return well to production.

Chemical Treatment Contingency

Follow the steps in this section if scale or paraffin is discovered. Be sure to contact WIE before starting this contingency.

1.1 RU pump truck and hard lines, configured to pump down tubing.

1.2 Pressure test pump and lines to specified high and low pressures.

1.3 Pump chemical treatment down tubing.
- Pump a small 1-3 bbl preflush of 2% KCl equivalent
- Pump acid type and volume specified in Well Specific Procedure

1.4 Limits while pumping treatment.
- Do not exceed 3 bbl/min
- Do not exceed 1000psi

1.5 Displace chemical treatment out of tubing and into formation by pumping a minimum of one tubing volume of 2% KCl equivalent.

Tbg OD (in)	Tbg ID (in)	Tbg Capacity (bbls/ ft)
2.063	1.751	.00298
2.375	1.995	.00387
2.875	2.441	.00579

1.6 RD pump and hard lines.

1.7 Notify Cherry Hlava (281) 366-4081 and report the actual treatment done for regulatory reporting.

2. For Paraffin

2.1 RU pump truck and hard lines, configured to pump down tubing.

2.2 Pressure test pump and lines to specified high and low pressures, Pump treatment down tubing.
- Pump ½ - 1½ drum of PAO 100 down tubing
- Pump ½ - 1½ drum of PAO 103 down casing

  *One drum is equivalent to 55 gallons

2.3 Reconfigure lines to pump down casing.

2.4 Pressure test pump and lines to specified high and low pressures specified high and low pressures.

2.5 Pump treatment down production annulus.
- Pump ½ - 1 drum of PAO 100 down tubing
- Pump ½ - 1 drum of PAO 103 down casing

  *One drum is equivalent to 55 gallons

2.6 Allow treatment to soak for a few hours.
- It may be necessary to allow treatment to soak for 24 hours+, discuss with WIE.

2.7 Notify Cherry Hlava (281) 366-4081 and report the actual treatment done for regulatory reporting.

Clean Out Contingency

1. Air Unit

1.1 MU and RIH with one of the following clean out assembly (WSL discretion)

Option A

- Bit or Mill (WSL discretion) for installed casing or liner string
- Bit Sub (if needed)
- Tubing Float(s)

Option B

- Modified mule shoe
- Tubing Float(s)

1.2 RIH to 30' above top of fill and break circulation. If a lot of liquid is observed in the wellbore, it may be necessary to break circulation above specified depth.

1.3 RU air/foam unit to pump down tubing and take returns from the casing flowing to the flowback tank. Note: should be able to take samples off flowline using flow "T" and valve.

1.4 Pressure test air unit and hard lines to 1200 psi.

1.5 Air/foam should include at minimum, but can be adjusted as WSL and well conditions deem necessary:

- 1.5 – 2 gals of foamer per 10 bbls water (this ratio can be adjusted depending on returns and well conditions).
  - Do not use more than 3 gals of foamer per 10 bbls water without discussing with WIE.
- 1 gal of corrosion inhibitor per 10 bbls water.
- Circulating pressure should range from 450 to 700 psi but pressures dependant on wellbore geometry.
  - Larger casings (larger flowing areas), deeper wells (more friction to flow) may require a second air/foam unit and/or more foamer per hour.
- Foam Sweeps will consist of foamer (typically ≤1 gal) poured directly down the tubing. If a more viscous sweep is needed, discuss options with WIE.

1.6 Bring pumps on and establish circulation (rates may be adjusted as WSL deems necessary).

- Limits
  - Do not exceed 1200 psi without consulting WIE.
  - Do not exceed 1350 cfm without consulting WIE.

1.7 Pump a foam sweep at start of clean out.

1.8 Circulate well until sand returns begin to diminish and returns become mostly air/foam.

1.9 Confirm that returns are clean, then RIH and re-establish circulation.

1.10 Continue pumping the proposed schedule and cleanout wellbore to depth specified on Well Specific Procedure pumping foam sweeps as necessary.

NOTE: If returns are repeatedly coming back light after re-establishing circulation, the WSL may choose to RIH with more joints of tubing before re-establishing circulation.

- If work-string becomes "sticky" and there are indications of getting stuck, record circulating tubing and return casing pressures (if available). Reciprocate pipe and rotate as string allows.
- If work-string becomes stuck continue circulating, if possible. Do not bleed down/off

either tubing or casing, record final circulation pressures, return casing pressures (if available), and the max pull applied.

Note: Do note exceed 75% of new pipe yield strength without consulting the WIE.

Common SJS Tubular Data

Tbg OD (in)	Tubing Grade	Connection	New tbg Yield lbs_f	75% Yield lbs_f
2.063	J-55	IJ	49,300	36,975
2.375	J-55	EUE	71,700	53,775
2.875	J-55	EUE	99,700	74,775

- If unable to pull tubing, move to **Stuck Pipe Contingency** and contact WIE.
- If tubing parts, move to **Fishing Contingency** and contact WIE.

2. Hydrostatic Bailer

2.1 MU and RIH to top of fill with Hydrostatic bailer.

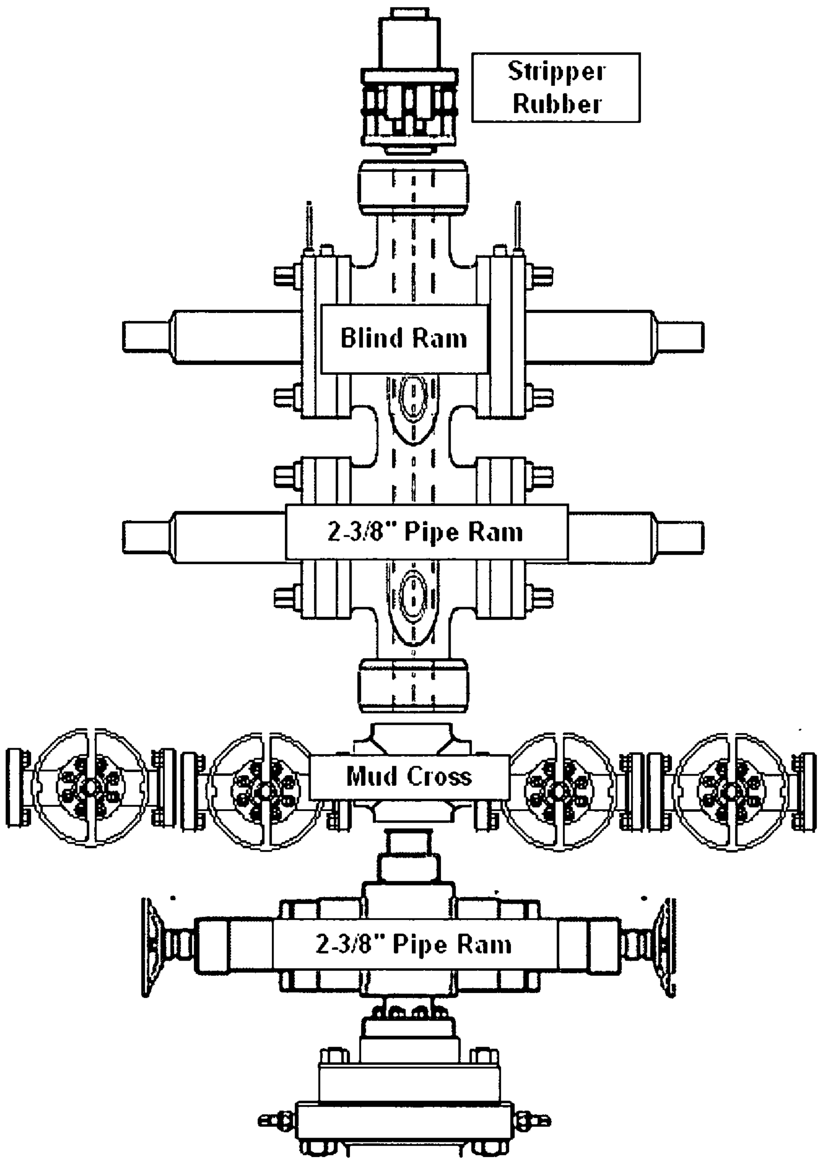
2.2 Work the hydrostatic bailer to allow sand to U-tube into the tubing.

2.3 If needed pump 2% KCl equivalent down the tubing x casing annulus to assist the bailer by adding additional hydrostatic head on the formation .
NOTE: Annular Volume between tubing and Casing can be found in Table 4. Annular Volumes.

2.4 Clean out well using hydrostatic bailer to specified depth, pumping water in production annulus as needed.

2.5 TOOH with tubing and hydrostatic bailer.

BOPE Configuration

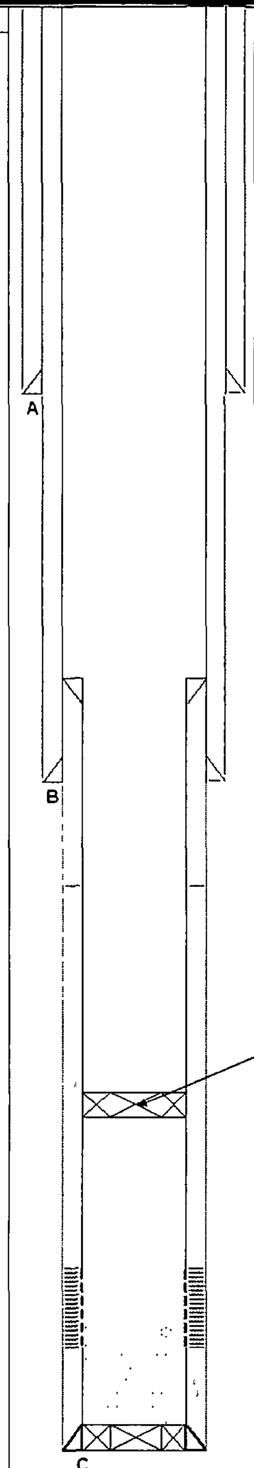


Current Wellbore Diagram

ATLANTIC LS 001A-MV

Current Wellbore bp

COMMENTS		EQUIPMENT DESCRIPTION



TOC 3630 Circ

CIBP @ 4900' 7/11/2011

PERFORATIONS:
Mesa Verde
4932' - 5562'
5607' - 6039'

"F" nipple @ 5960'

81,000# sd 162,000 gal water
67,000# snd 134000 gal water

Suspected sand fill

EOT @
5992

PBTD	6,052	MD	TVD
TD	6,069	MD	TVD

Spud 10-26-78 Tbg 5-9-79 Workovers 4-5-93

FIELD	Farmington		
WELL	ATLANTIC LS 001A-MV		
COUNTY			
API No	30045228770		
RKB ELEVATION		SEC	25
GL ELEVATION	6,624	TOWN	31N
RKB-GL		RANGE	10W
Lat 36 8674	Long -107 83129		

DIRECTIONAL DATA

MAX ANGLE		THRU	
KOP		TYPE	

PRODUCTION DETAIL

	Tubing	CASING
SIZE	2 3/8	
WEIGHT	4 7#	
GRADE	J-55	
DEPTH	5,992	
THREAD		
I D	1 995	
DRIFT	1 901	
BURST		
COLLAPSE	8,100	
CAPACITY	0 00387 bbl/ft	
# JOINTS	192	

PRODUCTION ASSEMBLY DETAIL

#	O D	I D	LENGTH	Description
	IN	IN	FT	
1	2 375	1 780	1 00	set @ 5960'
2				
3				
4				
5				
6				

CASING DETAIL

	#	SIZE	WGHT	GRADE	THREAD	DEPTH
	A	9 5/8	32 3	H-40		208
	B	7	23	K-55		3,811
75 jnts	C	4 1/2	11 6	K-55		3628-6069
	D					

PRESSURE DATA

BOTTOM HOLE PRESSURE	0958 PSI
Calculated using HASP + (0 1 * Top Perf)	
HIGHEST ANTICIPATED PRESSURE	150 PSI
SITP from offset MC 5-90 + 500 psi Safety Factor	
MAXIMUM ALLOWABLE SURFACE PRESS	
Rating of valves	
BOTTOM HOLE TEMPERATURE	
From PLT	

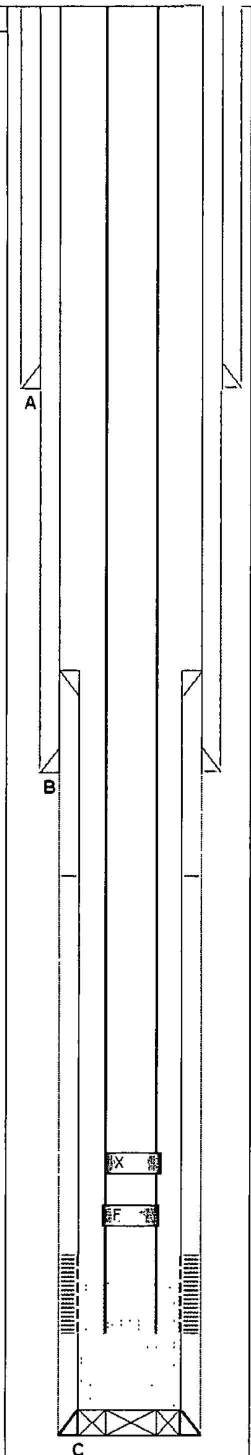
Prepared by Michael Morgan Date 28-Dec-2010

Proposed Wellbore Diagram

ATLANTIC LS 001A-MV

Current Wellbore bp

COMMENTS | **EQUIPMENT DESCRIPTION**



TOC 3630 Circ

75 jnts

PERFORATIONS:

Mesa Verde

4932' - 5562'

5607' - 6039'

"X" nipple @ ~ 5975'

"F" nipple @ ~ 5980'

Suspected sand fill

81,000# sd 162,000 gal water

67,000# snd 134000 gal water

EOT @
5990 +/-

FIELD	Farmington		
WELL	ATLANTIC LS 001A-MV		
COUNTY			
API No	30045228770		
RKB ELEVATION		SEC	25
GL ELEVATION	6,624	TOWN	31N
RKB-GL		RANGE	10W
Lat. 36 8674		Long -107 83129	

DIRECTIONAL DATA

MAX ANGLE		THRU	
KOP		TYPE	

PRODUCTION DETAIL

	Tubing	CASING	Liner
SIZE	2 3/8	7	4/1/2002
WEIGHT	4 7#	23	11 6
GRADE	J-55	K-55	K-55
DEPTH	~5990	3,811	3,628-6,069
THREAD			
I D	1 995	6 366	4 000
DRIFT	1 901	6 241	3.875
BURST			
COLLAPSE	8,100		
CAPACITY	0 00387 bbl/ft	0 0394	0 0155
# JOINTS	192		

PRODUCTION ASSEMBLY DETAIL

#	O D	I. D	LENGTH	Description
	IN	IN	FT	
1	2 375	1 780	1 00	set @ ~ 5975'
2	2 375	1 875	1 00	set @ ~ 5980'
3				
4				
5				
6				

CASING DETAIL

#	SIZE	WGHT	GRADE	THREAD	DEPTH
A	9 5/8	32 3	H-40		208
B	7	23	K-55		3,811
C	4 1/2	11 6	K-55		3628-6069
D					

PRESSURE DATA

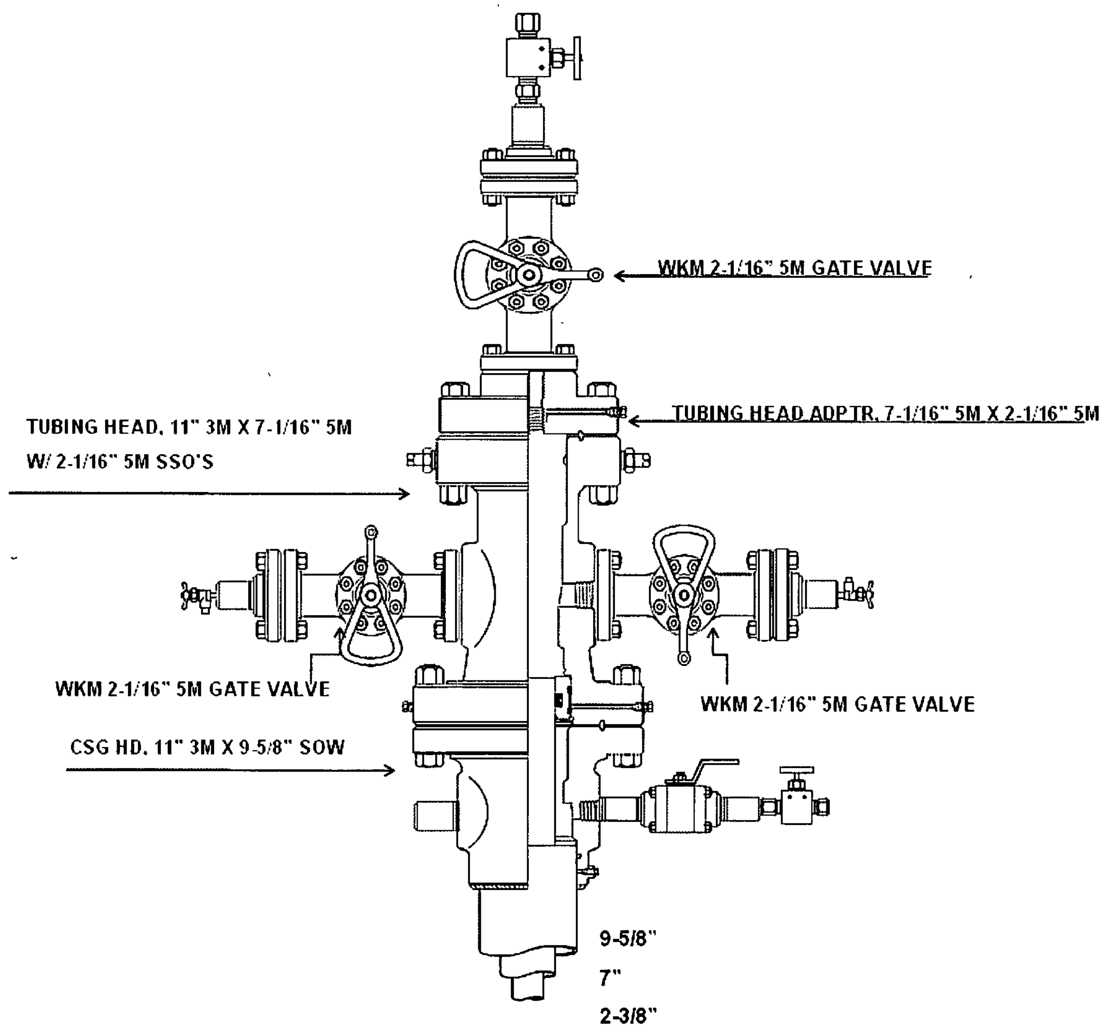
BOTTOM HOLE PRESSURE	753 9 PSI
Calculated using HASP + (0 1 * Top Perf)	
HIGHEST ANTICIPATED PRESSURE	150 PSI
MAXIMUM ALLOWABLE SURFACE PRESS	
Rating of valves	
BOTTOM HOLE TEMPERATURE	
From PLT	

Prepared by THM | Date 30-Dec-2010

PBTD	6,052	MD		TVD
TD	6,069	MD		TVD

Spud 10-26-78 Tbg 5-9-79 Workovers 4-5-93

New Wellhead Configuration



Current Wellhead Configuration and Photos

Well Name: Atlantic LS#1A
Date: 9-29-11