Form 3160-5
(August 2007)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB NO 1004-0135
Expires. July 31, 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.

SUBMIT IN TRIPLICATE - Other instructions on reverse side.

5. Lease Serial No.
NMNM013686

6. If Indian, Allottee or Tribe Name

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

1 Type of Well
☐ Oil Well ☐ Gas Well ☒ Other: INJECTION

8 Well Name and No.
PRITCHARD SWD 1 SWD

2. Name of Operator
BP AMERICA PRODUCTION CO.
Contact. CHERRY HLAVA
E-Mail: hlavacl@bp.com

9. API Well No.
30-045-28351-00-S1

3a. Address
200 ENERGY COURT
FARMINGTON, NM 87401

3b. Phone No. (include area code)
Ph: 281.366.4081

10 Field and Pool, or Exploratory
SWD MORRISON BLUFF ENTRADA

4 Location of Well (*Footage, Sec., T, R., M, or Survey Description*)
Sec 34 T31N R9W NENW 0615FNL 1840FWL
36.860250 N Lat, 107.770140 W Lon

11. County or Parish, and State
SAN JUAN COUNTY, NM

12. CHECK APPROPRIATE BOX(ES) TO INDICATE NATURE OF 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
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

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.)

BP respectfully requests permission acidize the above mention SWD well with 3000 gal 15% HCl with corrosion inhibitor @5% by weight.

Please see the attached procedure.

* MIT must stabilize for final 10min of the test. If the MIT fails to stabilize contact the NMOCD prior to proceeding.

RCVD MAY 18 '12
OIL CONS. DIV.
DIST. 3

Notify NMOCD 24 hrs prior to beginning operations

14 I hereby certify that the foregoing is true and correct.

Electronic Submission #137548 verified by the BLM Well Information System
For BP AMERICA PRODUCTION CO., sent to the Farmington
Committed to AFMSS for processing by STEVE MASON on 05/14/2012 (12SXM0208SE)

Name (*Printed/Typed*) CHERRY HLAVA — Title REGULATORY ANALYST

Signature (Electronic Submission) — Date 05/10/2012

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By STEPHEN MASON — Title PETROLEUM ENGINEER — Date 05/14/2012

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 Farmington

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 within its jurisdiction

**** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED ** BLM REVISED ****

NMOCD AV

Pritchard SWD 1
SWDW restore

bp

General Information:

Job Objective:	SWDW restore	**Date:**	12/1/2011
Project #:	X4-00VRR	**Total AFE Amount:**	$171,000

Contact:

Intervention Engineer:	David Wages	**p.** (281) 366-7929	**c.** 406-231-4679
Base Management Engr:	Carter Clemens	**p.** (281-366-1384)	**c.**
Production Team Leader	Baynard Duke	**p.** (505-326-9207)	**c.**
Intervention Engineer	Phyllis Loose	**p.** (970) 247-6829	**c.** (970) 759-5202
Intervention Engineer	Trevor McClymont	**p.** (281) 366-1425	**c.** (281) 546-2477

Well Information:		**Injection Data:**	
API Number:	30-045-28351	**Current Injection Rates**	
Present Status	Injection	**Water (bpd)**	150 BWPD @ 1660 psi
PBTD	8620'	**Expected Injection Rates**	90 mcfd
		Area Classification:	LCO
County	San Juan		
State	New Mexico	**Priority**	1
Surface Location:	D SEC. 34, T31NN, R09WW		
Cost Center:			
Well FLAC:			
Lease FLAC:			
Lateral/Run	NA/74		
Meter #:	FAC0000013		
BP WI:	100%		
Reg Approval Req'd:	Yes		
Partner Approval Req'd	No		
Landowner Approval Req'd	No		
Additional Approvals	No		
Restrictions:	Seasonal		
Compliance/Issues	No		

Prepared By: __________

Reviewed By: __________

Approved By: __________

Policy Reminder

Any changes to the written procedure requires an MOC

MOC (except BoD/SoR) approvals during execution have been delegated to the OTL

Basic Job Procedure:

1. MIRU. Test connections
2. Set plugs
3. ND/NU test
4. TOH tubing
5. Cleanout, Acidize
6. TIH w/ tubing. Test tubing
7. ND/NU test
8. RD Service Unit.

Well History:

Spud date: 11/11990
- Did not get full returns on Injection casing cement job, poor cement from 7122' to DV tool @ 5418'

Completed: 1/1991
- Perforated then Frac:
- Frac down casing with 3828 BFW 30# X-L titrate, 220,000# 20/40 sand, AIR 44 BPM, AIP 1000 psi.

Well Servicing: 7/1996
- Open well to flowback tank, pumped 770 gal of super a-sol and displace w/ 85 bbls water. Max rate: 1.3 BPM, pressure 1575 psi. Acidize all perfs w/ FE HCl. Open well up on 1/2" choke, rec 254 bbls to clean well up after acid job.

Well Servicing: 1/2001
- Inject plastic in secondary seals, test OK
- Perform MIT on tubing, OK
- Could not remove plug, had to move Coil out, cleanout above plug then latch and remove.
- RU SLB, pump 4000 gal 15% HCl, starting rate: 5 BPM @ 2100#, ending: 8 BPM @ 2300psi. ISIP: 819 psi

Well Servicing: 10/2011
- Test secondary seals: tbg to 3000 psi, csg to 1000 psi, OK

Completion Information				
End of Tubing:	8324'		**Tubing Size:**	3-1/2" Internal coat TK 69
Liner Size and Top:	N/A		**Casing size:**	7"
PBTD:	8620'		**AL-2 Lok-Set Packer:**	8295'

Maximum Anticipated Surface Pressure 1470 psi

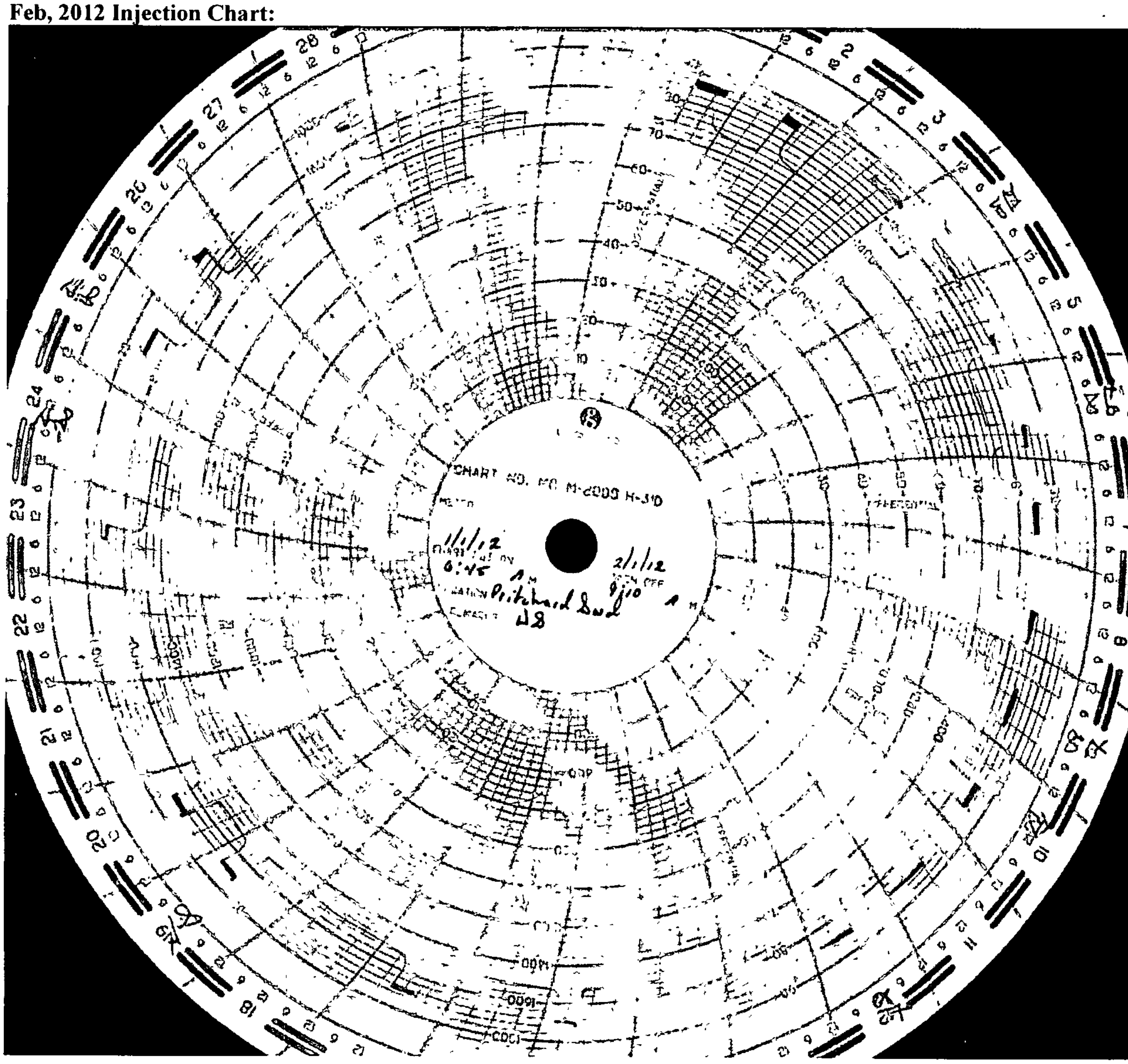
Low Pressure Test	High Pressure Test
250 psi	2000 psi

These are the high and low pressure testing values unless otherwise stated.

Requirements for this procedure:
- 12.3 ppg CaCl2 kill weight fluid: approx 700 bbls (one wellbore volume~339 bbls to bottom perf), Recipe below
- Replacement 3-1/2" N-80 9.2# internally tubing coated with TK-69
- Replacement seals for HEL On-Off tool (Baker Manufactured, can get seals, contact Thomas Maricle 361.550.5819)
- If MIT of casing or tubing fails, we might replace the packer. Recommend Hornet
  - Hornet Model 600-292, 3-1/2 EU 8rd thread box x pin

Pritchard SWD #1

Feb, 2012 Injection Chart:



Avg Stabilized Shut-In Pressure: 1470 psi
Estimated BH Pressure 5100 psi @ 8382': 5100 psi
Avg surface temp and Temperature gradient: 50 deg F and 2 deg F/100 ft
Kill Weight Fluid corrected for temperature effects and 100 psi overbalance:

12.5 ppg

Pritchard SWD #1

Brine Recipe:

- 12.5 ppg CaCl2/CaBr2 Kill Weight Fluid
- BARABUF (pH Buffer)
    - BARABUF pH buffer will dissolve in water and raise the pH of an aqueous system to 10.3. At pH 10.3, no more BARABUF pH buffer will dissolve. The remaining undissolved product will dissolve if the pH starts to fall and thereby act as a pH buffer. BARABUF pH buffer can be safer to use than caustic soda.
    - BARABUF will be added at ¼ lb/bbl to raise pH to 8-8.5.
    - BARABUF will be added to dilution water at the start of job and be monitored during the job for additional treatment
- OXYGON (O2 Scavenger)
    - OXYGON™ scavanger is a non-sulphite oxygen scavenger designed for use in packer fluids and water based fluids to help prevent oxygen corrosion. OXYGON scavanger is compatible with all brine types, is readily soluble, fast acting and is suitable for use up to 325°F (163°C). Overtreatment should be avoided.
    - Packer fluid treatment should be 0.1 lb/bbl (0.29 kg/m³) with appropriate level of BARACOR 100 inhibitor.
    - Base the treatment of circulating fluids on oxygen content. Work with WIE and supplier to confirm additive amount.
- BARACOR 11 (Corrosion Inhibitor)
    - BARACOR® 100 corrosion inhibitor is a film forming amine that is water soluble and effective for use in solids-free brines and packer fluids. BARACOR 100 corrosion inhibitor is effective up to 400°F (204°C) in monovalent brines and up to 300°F (149°C) in calcium and zinc brines.
- ALDACIDE G (Bactericide)
    - A glutaraldehyde solution, is used to control bacteria growth in water-based drilling fluids. ALDACIDE G is recommended for use with systems containing polymers that are readily biodegradable (i.e. starches, biogums, etc.).
    - ALDACIDE G will be added 1 five gallon can per 125 bbl of CaCl/CaBr for this application we will use 3-5 cans.

Viscous Pill Recipe

- 15 bbls Fresh water
- ~One 5 gallon can of LIQUI-VIS EP per 5 bbls fresh water.
    - LIQUI-VIS EP viscosifier is a high purity HEC polymer dispersed in a water soluble carrier. It is designed to viscosify fresh water and low weight brines for drill-in fluid applications. LIQUI-VIS EP viscosifier does not increase gel strength or provide improved fluid loss control. LIQUI-VIS viscosifier can also be used to prepare displacement spacers and clean the hole while milling. This product mixes easily in all brines, is acid soluble, and is suitable for use up to 200°F (93°C).

- Brine QAQC:
    - KWF weight: 12.3 ppg - 12.4 ppg
    - KWF pH: 8-8.5
    - Viscous pill weight: 8.34 ppg - 8.5 ppg
    - Viscous pill pH: 7 +/-1
    - Viscous Pill Viscosity: Minimum 20 cp AV, refer to viscosity chart

Contact List				
Stephen Henzler	Operations Leader Baroid Halliburton O. 303.899.4725 M. 303.301.4341		Gary Przekurat	Baroid Service Coordinator O. 505.325.1896 M. 505.320.8410

Standard Site Preparations

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. Raptor 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 for proper flange connection

2. Work with OC through CoW and w/P&S to develop a plan to move or temporarily relocate equipment that prohibits well servicing/plugging objectives.
3. If the data bases indicate H2S is present then have a Service Company check for H2S on tubing and all casing annuli with Dreiger Tube. If H2S is present then notify WIE to discuss options.
4. Complete Handover Documentation between Operations and Functional Wells Team per ADM 61006.
5. Check and record shut in casing pressure (SICP), shut in tubing pressures (SITP), intermediate casing pressures (SIICP), Bradenhead pressures (SIBH), and or flowing pressures (FTP, FCP) in Open Wells daily.
6. If SIICP or SIBH exist then notify the Well Intervention Engineer (WIE) and Wells Field Superintendent (WFS). Notify WIE if water or gas flow is observed from any annulus.

Slickline/Set Plugs:

7. With BP WSL on location, 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.
   - Reference Nag-GP 42-0100 - 'Hot and Odd Bolting Group Practice
   - If any problems are encountered or 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.
8. Ensure production equipment is LOTO and well is shut in.
9. Move in slickline unit, equipment and crew.
10. RU slickline using slickline NOP (NAG-NOP-SL01). Pressure test lubricator 250 psi low and 2000 psi high for 5 minutes for each test. Record passing test in OpenWells.
11. RIH with gauge ring to nipple equipment at 8258' to locate any tools or tubing obstructions. POOH. Record depth of tag.
    - ID of internally coated tubing is 2.827"
12. RIH and tag fill, ID of R & F-nipple below packer is 2.25"

Set Barrier

13. There must be a minimum of 2 mechanical pressure barrier in tubing in order to break containment, barriers shall conform with DWOP, NAG-GP 10-36-1, and SJ-SOP-WI-BKCNT-Rev01. Plugs shall be one of the following:
    - Pump through plug installed in a nipple
    - Setting a cement retainer in the tubing after discussing with WIE and WFS.
    - The second barrier will be a two way check installed in the tubing hanger

Setting Plugs in Profile Nipple

- NAG-NOP-SL01 shall be followed for all slickline operations.
- If Slickline operations tagged nipple profile, then set blanking plug with an equalizing assembly in profile nipple: F-Nipple @ 8311' ID is 2.25", R-Nipple @ 8323' ID is 2.25" from previous tubing string in hole. POOH.

Note: These is an 3-1/2" x 2-3/4" F-nipple @ 8258' that we **do not** want to set a plug in.

- Negative test plug by bleeding tubing pressure to 0 psi, shutting well in and monitoring well. If pressure does not increase in 15 min after shutting in well then this is a negative test of the barrier. If pressure increases then discuss options with WIE.
- RD SL
- If unable to set plug in nipple then use **Setting Cement Retainer in Tubing**

Setting Cement Retainers in Tubing

If unable to set a plug in the nipple or in the tubing then a cement retainer can be set in the tubing after discussing with the WIE and WFS.

- RU E-Line lubricator to top of tree
- Pressure test lubricator to specified low and high pressures.
- RIH with appropriate sized cement retainer for tubing and set at safe depth determined from slick line diagnostics
- Negative test retainer by bleeding tubing pressure to 0 psi, shutting well in and monitoring well. If pressure does not increase after shutting in well then this is a negative test of the barrier. If pressure increases then discuss options with WIE.
- RD E-Line
- If unable to set retainer then discuss options with WIE and WFS.

Pressure test injection string

After installing the downhole barrier, we need to test the integrity of the injection string

14. RU testers to tree
15. PT injection string to 250 psi low for 5 min and 2000 psi high for 30 min, chart test.
    - A successful MIT is a 30 min test with no visible leaks, a stabilized decline less than 5 psi/min for the final 15 min of the test period and a maximum pressure loss of 100 psi.
    - Monitor backside pressure during test.
    - PT pass, the tubing is good and the leak is coming from the packer
    - PT fail or casing pressure increases, the packer may be good but the tubing or on-off tool is leaking.
16. RD testers

Negative test casing

After installing the downhole barrier, we need to test the integrity of the packer/On-off tool/casing.

17. Remove flowline piping.
18. Install second casing valves. Open inside casing valve to negative pressure test valve.
19. RU flowlines and flowback tank to second casing valve.
20. RU testers to monitor tubing pressure and casing pressure
21. Bleed tubing pressure to zero
22. Bleed off casing pressure to zero or lowest pressure possible in 15 min to flowback tank
23. Monitor casing and injection string pressure for any increase/decrease in pressure, chart pressures.
24. PT casing to 250 psi low for 5 min and 600 psi high for 30 min, chart test.
    - A successful MIT is a 30 min test with no visible leaks, a stabilized decline less than 5 psi/min for the final 15 min of the test period and a maximum pressure loss of 50 psi.

- Monitor injection string pressure during test.

25. Shut in well, RD testers.

Punch Circulating holes:
Using E-line:

26. MIRU E-line unit and crew
27. MU E-line BHA to shoot circulating holes:
    - 1-9/16" RTG, HMX explosive, 0.32" EH size, 0.125"-0.218" Penetration.
    - Confirm gun selection with engineer and service company
28. RU E-line lubricator to tree
29. PT E-line lubricator to 250 psi low and 2000 psi high for 5 min each, chart test
30. RIH and shoot circulating holes at 8280'
31. POH, w/ E-line RD lubricator
32. RU pump and lines to pump down the tubing while taking returns up the tubing x casing annulus to a flowback tank.
33. PT pump and lines to 250 psi low and 1000 psi high for 5 min each.
34. Pump a sufficient volume of 2% KCl-e water down the tubing to confirm we can circulate down the tubing and up the tubing x casing annulus.

Punch Circulating Holes Using slickline:

1. MIRU slickline unit and crew
2. MU BHA to punch circulating holes:
   - SL conveyed tubing punch
3. RU SL lubricator to tree
4. PT SL lubricator to 250 psi low and 2000 psi high for 5 min each, chart test
5. RIH and punch circulating holes at 8280'
6. POH with SL and RD lubricator
7. RU pump and lines to pump down the tubing while taking returns up the tubing x casing annulus to a flowback tank.
8. PT pump and lines to 250 psi low and 1000 psi high for 5 min each.
9. Pump a sufficient volume of 2% KCl-e water down the tubing to confirm we can circulate down the tubing and up the tubing x casing annulus.

Pump KWF:

35. RU pump and lines to pump KWF down the tubing while taking returns up the tubing x casing annulus
36. Pressure test flowback lines and choke manifold to 250 psi low and 2500 psi high
    - Ensure choke manifold is installed in flowback lines, refer to diagram attached.
    - Anchor lines using cement blocks.
    - High test is a 15 minute test, with no visible leaks, a stabilized pressure decline less than 10 psi/min over a 5 minute period and the total pressure loss does not exceed 5%.
37. Ensure Brine and viscous pill QA/QC is performed, consult with Baroid service rep and WIE as necessary

- KWF weight: 12.3 ppg - 12.4 ppg
- KWF pH: 8-8.5
- Viscous pill weight: 8.34 ppg - 8.5 ppg
- Viscous pill pH: 7 +/-1
- Viscous Pill Viscosity: Minimum 20 cp AV, refer to viscosity chart at beginning of procedure

38. Pressure test pump and lines to 250 psi low and 2500 psi high for 5 min each
39. Pump 15 bbls of Liqui-Vis viscous pill followed by 282 bbls 12.5 ppg $CaCl_2/CaBr_2$ KWF down the tubing while taking returns up the annulus following Kill schedule attached.

Note: This pump schedule does not include friction pressures while pumping. 200 psi at the end will give you 200 psi overbalance due to the choke plus friction pressure up the annulus plus 100 psi overbalance from kill weight fluid.

40. Continue pumping 10 more bbls of kill weight fluid, once ~290 bbls have been pumped down the tubing, slowly bring down pumps and allow casing pressure to bleed off to 0 psi. Ensure tubing and casing pressure remains at zero.
41. Shut in and secure well, RD pump and lines.
42. MIRU lubricator to set TWC in tubing hanger
43. PT lubricator to 250 psi low and 2000 psi high for 5 min each, chart test
44. Install TWC
45. RD lubricator.

MIRU Service Unit

46. MI Service Unit
47. Install diversion lines from casing valves to flowback tank.
    - Ensure choke manifold is installed in flowback lines, refer to diagram attached.
    - Anchor lines using cement blocks.
48. Pressure test flowback lines and choke manifold to 250 psi low and 2500 psi high
    - High test is a 15 minute test, with no visible leaks, a stabilized pressure decline less than 10 psi/min over a 5 minute period and the total pressure loss does not exceed 5%.
49. If packer pressure tested successful and no flow will come to surface, release pressure from tubing x casing annulus by opening casing valves to flowback tank if necessary.
50. Replace any corroded bolts and or nuts on wellhead in preparation for breaking containment as identified by wellhead service co.
51. RU rig

ND WH / NU BOP

52. Nipple down tree to tubing hanger.
53. NU San Juan South BOPE using attached BOP Diagram. Rams will be sized for the tubing in the well.
54. Function test and pressure test BOPs to 250 psi low and 2500 psi high for 5 in each, chart test. Perform accumulator test. Record in Open Wells.

55. Monitor casing pressure with gauge throughout workover.
56. RU lubricator to BOPE
57. PT lubricator to 250 psi low and 2000 psi high for 5 min each, chart test
58. Remove TWC in tubing hanger
59. RD Lubricator

Slickline to install pump thru plug in profile nipple

60. Move in slickline unit, equipment and crew.
61. RU slickline using slickline NOP (NAG-NOP-SL01). Pressure test lubricator 250 psi low and 2000 psi high for 5 minutes for each test. Record passing test in OpenWells.
62. RIH with pulling tool and pull blanking plug set in profile nipple. POH.
63. RIH and set pump thru plug in F-profile @ 8311' ID 2.25" or R-profile @ 8323' ID 2.25". POH.
64. RD slickline.

Pump additional KWF

65. RU pump and lines to pump KWF down the tubing
66. Pump 12 bbls 12.3 ppg KWF down the tubing, this is the volume from the packer to the bottom perforation.

Unseat packer and POH

67. MI trip tank and install lines from trip tank to flow cross.
68. Fill trip tank with 12.3 ppg KWF. Ensure fluid level is correct.
69. Unseat packer
    a. Packer currently has 44,000# compression on it.
    b. PU to where there is 3000 to 6000# compression on the packer (On-off tool has ~2" of travel, use to find string weight), then rotate to the right from 8 to 10 turns at the tool until the tool moves down the hole, Once a jump is felt, or a loss of string weight continue rotating w/ 3000# on the packer 8-10 turns then begin pulling out of the hole. On inverted packer, threads are switched but unseating procedure is same as regular AL-2.
70. POH with injection string, lay down any joints that appear to have significant corrosion, replace any collars as necessary.

Note: Ensure trip tank levels correspond to volume of steel being pulled out of the hole which is 4 bbls/1000' (for 3-1/2" tubing w/ 2.847" ID), if the trip tank levels indicate we are losing fluid past the packer, notify WIE.

Well Cleanup

Note: Mill run will be performed at this time if scale is believed to be too heavy or too hard to get a bit and scraper through the injection casing. Follow **Mill run Contingency.**

Mill run (if agreed on with engineer)

1. Make up BHA for cleaning out scale on casing (from Bottom to top):
    - Mill for 7" casing (recommend 6-1/8" OD)
    - Float or bit sub
    - Drill collars as necessary
    - Workstring with replaced joints
2. RIH with mill and mill up all tight spots to fill or depth agreed on with engineer. Max weight on bit: 4000#

3. POOH

Note: Bit and scraper run will be performed at this time if scale is believed to be built up on the inside of the injection casing. Follow **Bit and scraper run Contingency**

Bit and scraper run (if necessary and agreed on with engineer)

1. Make up BHA for bit and scraper run (from bottom to top):
   - Bit
   - Scraper
   - Float
   - Workstring
2. RIH w/ bit and scraper for 7" casing to Entrada perfs @ 8382'-8600'. Reciprocate across perfs.
3. POOH with bit and scraper.

RIH with completion string

71. RIH with 3-1/2" L-80 9.3# injection tubing internally coated with TK-70XT with BHA to +/- 8324'. Min drift ID of tubing is 2.827"
    - Wireline re-entry guide/mule shoe
    - 3-1/2"x 2.813" profile XN-nipple (or similar) no-go ID: 2.666" w/ plug pre installed Chrome plated inside and outside
    - 6 ft 3-1/2" L-80 9.3# tubing sub, 8rd threads, nickel plated inside and outside.
    - Hornet Model 600-292, 3-1/2 EU 8rd thread box x pin, nickel plated everything metal
    - 1 jt 3-1/2" L-80 9.2 # tubing, 8rd threads
    - 3-1/2"x 2.813" profile X-nipple, chrome plated
    - 3-1/2" N-80/L-80 9.2/9.3# tubing, 8rd threads L-80 coated with TK-70XT, N-80 coated with TK-69 internally

Note: if tubing pulled from well is in good shape, internal coating looks good, no corrosion or pitting on OD, pins and collars look good, we will re use the existing injection string, **please use L-80 material internally coated with TK-70 XT as replacement material.**

72. Fill tubing with 12.3 ppg KWF prior to installing hanger and TWC.
73. MU redressed tubing hanger with pre-installed and pre-tested TWC and TIW valve on lifting pup. (If a plug was successfully set in nipple profile, the TIW valve is not necessary)
74. Set packer @ 8300' total string weight should be 50,000# with 12.3ppg fluid inside and outside the tubing, land tubing with 40,000# compression on packer.

Spacing out procedure

1. 1 joint above landing depth, rotate tubing to the right to allow packer to be set. Place a mark on the tubing.
2. Slack off until 40,000 lbs of string weight is on the packer. Mark the tubing.
3. Unseat packer, measure the distance between the marks.
4. With the hanger installed, land tubing. Mark the tubing level with the rig floor.
5. Pick up the distance measured in step 3, rotate the tubing to the right and set the packer.

Note: if 40,000 lbs set down weight is not on the packer, unseat packer and re-spaceout.

6. Continue to land tubing

Note: 12.3 ppg CaCl2 kill weight fluid will be used as the packer fluid.

75. Land tubing.

76. ND BOPE to tubing hanger flange. NU tree.
77. If wellhead is equipped with test ports, test well head seals to rated working pressure
78. RU lubricator to remove TWC installed in hanger
79. PT lubricator to 250 psi low and 2000 psi high for 5 min each, chart test.
80. Retrieve TWC
81. RD lubricator
82. RU Slickline to top of tree referring to NAG-NOP-SL01
83. Pressure test SL lubricator to 250 psi low and 2000 psi high for 5 min each
84. RIH with appropriate tools to equalize and remove plug in profile nipple. POOH
85. RD SL.

Pump Acid Treatment

86. MI acid units and crew
87. RU pump and lines to pump down the tubing, all fluid will be injected into the well, we will not take any returns.
88. PT pump and lines to 250 psi low and 2500 psi for 5 min each, chart test.
89. Pump acid treatment per schedule below:
    a. 5 bbls 2% KCl water spacer
    b. 3000 gal 15% HCl with corrosion inhibitor at 5% by weight
    c. Flush with 70 bbls 2% KCl water
    d. Max rate: 5 bbl per min
    e. Max pressure: 2300 psi, set kickouts on pump at 2300 psi.
90. Shut in well, RD pumping equipment

Pressure test casing

Note: Contact Coal operations team before performing MIT

Note: Contact NMOCD representative before performing MIT

91. RU testers to PT casing, packer and hanger seals.
92. PT casing to 250 psi low for 5 min and 600 psi high for 30 min, chart test.
    - A successful MIT is a 30 min test with no visible leaks, a stabilized decline less than 5 psi/min for the final 15 min of the test period and a maximum pressure loss of 60 psi.
    - Monitor tubing pressure during test. Tubing pressure must remain at 0 psi for a successful test.
93. Bleed off casing pressure to zero to flowback tank
94. Shut in well, RD testers.

Return Well to Injection

95. RD and release all equipment. Remove all LOTO equipment
96. Follow CoW procedures to return well back to injection
97. Complete Handover document between functional Wells Team and Operations per ADM 61006.
98. Ensure all well work details and wellbore equipment is entered in 'OPEN WELLS".

Contingencies

Stuck Pipe Contingency

Follow the steps in this section if unable to free tubing. Be sure to contact WIE and WIOS before starting this contingency.

1. **Estimate free point**

1.1 Determine total string weight

Total String Weight = length of tubing x tubing weight.

If the weight indicator is zeroed with the block, add the block weight to string weight

1.2 If the wellbore is full of fluid refer to Table 2 to correct total string weight for buoyancy.

1.3 With the pipe stationary in the slips, mark a line to denote the pipes un-stretched position.

1.4 Apply sufficient pull to stretch pipe 3.5"/1000' Use Table 3 – Over Pull Weights for amount of pulled required.

1.5 With pull applied mark the position to denote stretched position.

1.6 Estimate location of free point using the formula below.

Free Point Estimate = (Distance between pipe marks (in) / 3.5) x 1,000

2. **Determine Free point**

2.1 RU E-Line unit w/ lubricator of sufficient length to accommodate the entire E-line BHA, WL BOPE, pump-in tee to BOPE.

2.2 Test to pressures specified in the Well Specific Procedure.

2.3 Make-up E-Line BHA with free point tool and CCL and RIH to well above estimated free point.

2.4 Activate tool to bite into side of tubing. Once set, pull recommended stretch on tubing, and hold for duration prescribed by the E-line service hand to get accurate free point reading.

- If free point tool indicates free pipe movement, release tool and move down hole 100' and retest. Record stretch data.
- If free point toll indicates little or no movement, move up hole 100' and retest. Record stretch data.

Location of free pipe is determined by the deepest point where free point tool indicates full stretch.

2.5 Once stuck point is located, Record and POOH with free point tool.

3. **Cut Tubing**

3.1 RU E-line with chemical cutter and CCL.

Review Chemical Cutter manufacturer's explosive safety checklist as a guide to ensure that all explosive and chemical safety measures are identified and being followed..

3.2 RIH with chemical cutter to cut tubing at determined free point.

Ensure MSDS sheets are available for any chemical used in cutting operations, personnel involved with cutting operations are trained and qualified, and emergency medical treatments are available in the event of exposure (e.g. eyewash stations, drench showers and antidotes/neutralizing agents) per DWOP 19.3.1.

3.3 Position chemical cutter so the cut is made well into the body of pipe and is **NOT** positioned on an upset or collar.

3.4 Pull pipe and hold in tension, activate cutting tool.

3.5 POOH with chemical cutter, ensure cutter fired.

3.6 RD E-line and POOH with recovered tubing if successful. It may be necessary to apply pull to tubing to get free. **DO NOT EXCEED 75% of new tubing yield without consulting the WIE.**

3.7 Determine amount of fish left in the hole.

3.8 Contact WIE and move to **Fishing Contingency**

Fishing Contingency

Follow the steps in this section to recover pipe. Be sure to contact WIE and WIOS before starting this contingency.

1. PU workstring.
2. If the location and condition of top of fish is unknown, MU workstring appropriate sized lead impression block.
3. RIH with impression block and carefully set down on top of fish only once. POOH with impression block and analyze impression block to determine best fishing tool.
4. MU fishing BHA with one of the following options.
   Option A
   - Releasing Overshot appropriately sized for fish
   - Mechanical Jars

   Option B
   - Releasing Spear appropriately sized for fish
   - Mechanical Jar

   Option C
   - Fishing assembly suggested by WIE and documented via email MoC.
5. RIH with fishing tool and tag top of parted tubing.
6. Work fishing tool over (or into) the top of parted tubing and latch on tubing.
7. POOH with remainder of tubing out of well, lay down parted tubing and any bad joints. **DO NOT EXCEED 75% of new tubing yield without consulting the WIE.**

Table 2—Buoyancy Factors

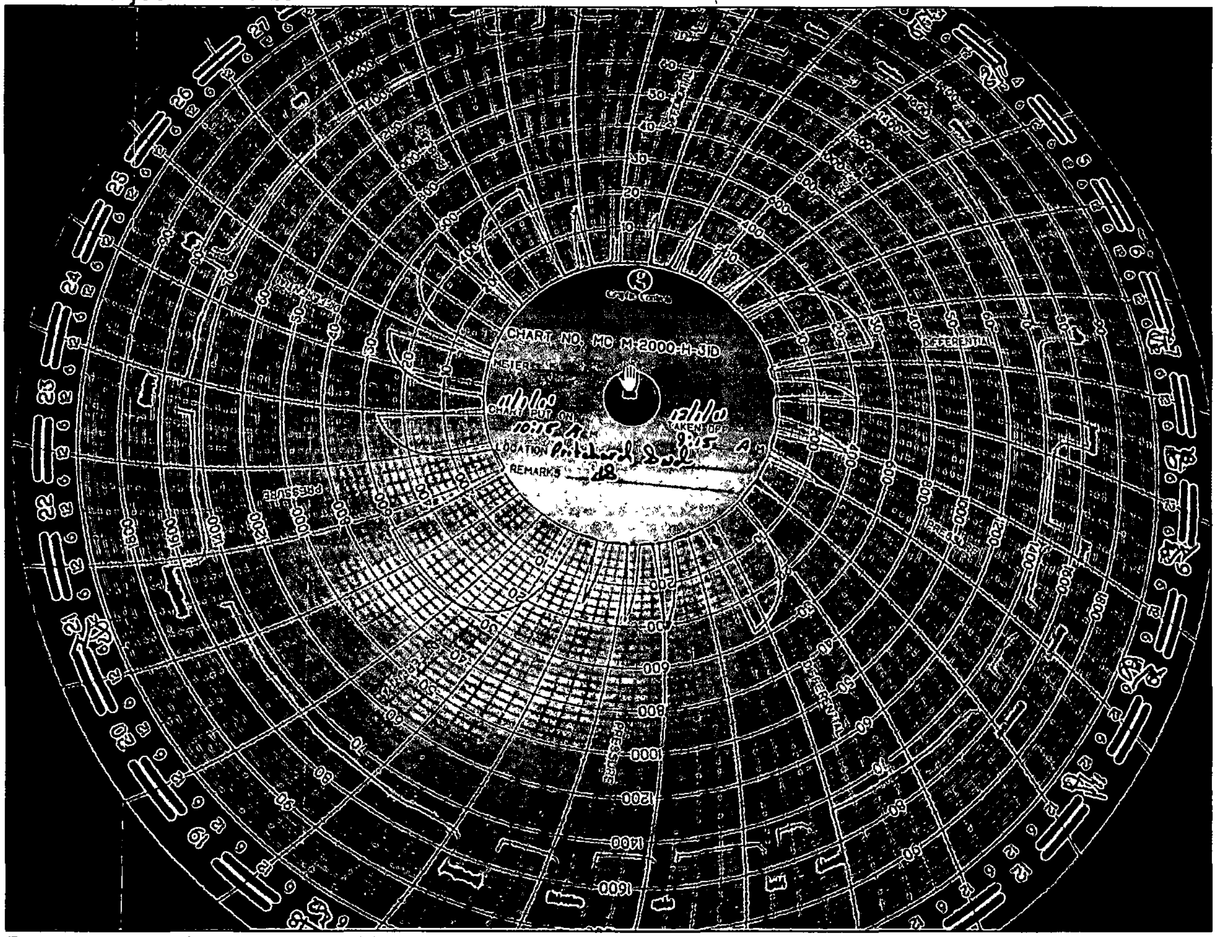
Fluid Weight (lb/gal)	Buoyancy Factor
8.4	0.872
8.6	0.869
8.8	0.866
9.0	0.862
9.2	0.859
9.4	0.856
9.6	0.853
9.8	0.850
10.0	0.847
10.2	0.844
10.4	0.841
10.6	0.838
10.8	0.835
11.0	0.832
11.2	0.829
11.4	0.826
11.6	0.823
11.8	0.820
12.0	0.817
12.2	0.814
12.4	0.811
12.6	0.807
12.8	0.804
13.0	0.801
13.2	0.798
13.4	0.795
13.6	0.792
13.8	0.789
14.0	0.786
14.5	0.778
15.0	0.771
15.5	0.763
16.0	0.756
16.5	0.748
17.0	0.740
17.5	0.733
18.0	0.725
18.5	0.717
19.0	0.710
19.5	0.702
20.0	0.695

Table 3—Overpull Weights

Pipe OD (in.)	Pipe Weight (lb/ft)	3 1/2-in. Stretch Tensions
Tubing		
1	1.80	4,000
	2.25	5,000
1-1/4	2.40	5,500
1-1/2	2.90	6,500
2-1/16	3.40	7,500
2-3/8	4.70	10,000
	5.30	12,000
	5.95	13,000
2-7/8	6.50	14,000
	7.90	17,000
	8.70	19,000
3-1/2	9.30	20,000
	10.30	23,000
	12.95	28,000
4	11.00	24,000
	13.40	29,000
4-1/2	12.75	28,000
	15.50	34,000
	19.20	42,000
Drillpipe		
2-3/8	6.65	15,000
2-7/8	10.40	23,000
3-1/2	13.30	30,000
4-1/2	16.60	36,000
5	19.50	43,000
Casing		
5	15.00	33,000
5-1/2	17.00	38,000
6-5/8	24.00	53,000
7	35.00	77,000
7-5/8	29.70	66,000
8-5/8	40.00	88,000
9-5/8	43.50	96,000
10-3/4	45.50	100,000

Pritchard SWD #1

Entrada Injection Profile



Red line: Injection pressure, 1670 psi when injecting, 1470 when shut in.
Blue line: 31 psi when not injecting, 0 psi when injecting.

Pritchard SWD #1

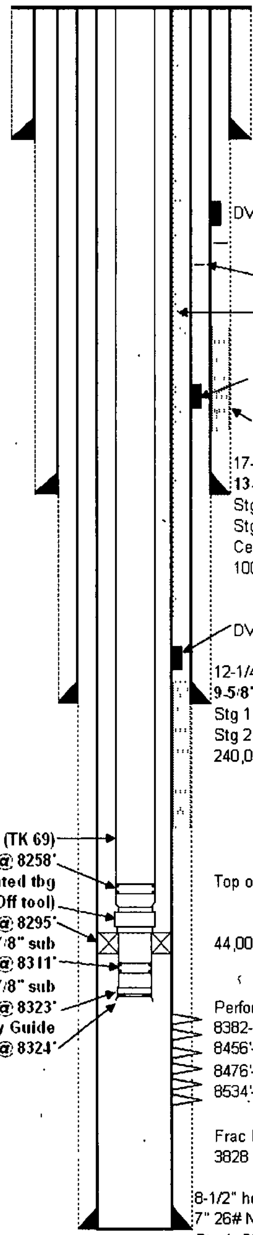
Current Wellbore

bp

Pritchard SWD #001
Coal
API # 30-045-28351
Unit C - Sec 34 - T31N - R09W
San Juan County, New Mexico

Workover History
Jan 1991 - Drilled and Completed
Jul 1996 - Acid Treatment with HCl
Jan 2001- CT cleanout, Acidized
Jan 2003 - Re-acidized with HCl and foam

Ojo Alamo	1612'
Kirtland	1680'
Fruitland	2560'
Pictured Cliffs	2882'
Lewis	3150'
Mesaverde	4650'
Mancos	5330'
Gallup	6262'
Dakota	7230'
Morrison	7670'
Bluff	8085'
Entrada	8380'



Pritchard SWD #1

Proposed Wellbore

bp

Pritchard SWD #001
Coal
API # 30-045-28351
Unit C - Sec 34 - T31N - R09W
San Juan County, New Mexico

Workover History

Jan 1991 - Drilled and Completed
Jul 1996 - Acid Treatment with HCl
Jan 2001- CT cleanout, Acidized
Jan 2003 - Re-acidized with HCl and foam

Ojo Alamo	1612'
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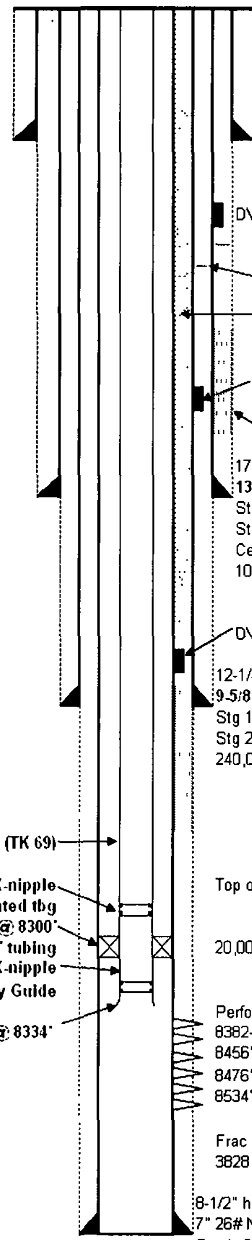
Mancos	5330'
Gallup	6262'
Dakota	7230'
Morrison	7670'
Bluff	8085'
Entrada	8380'



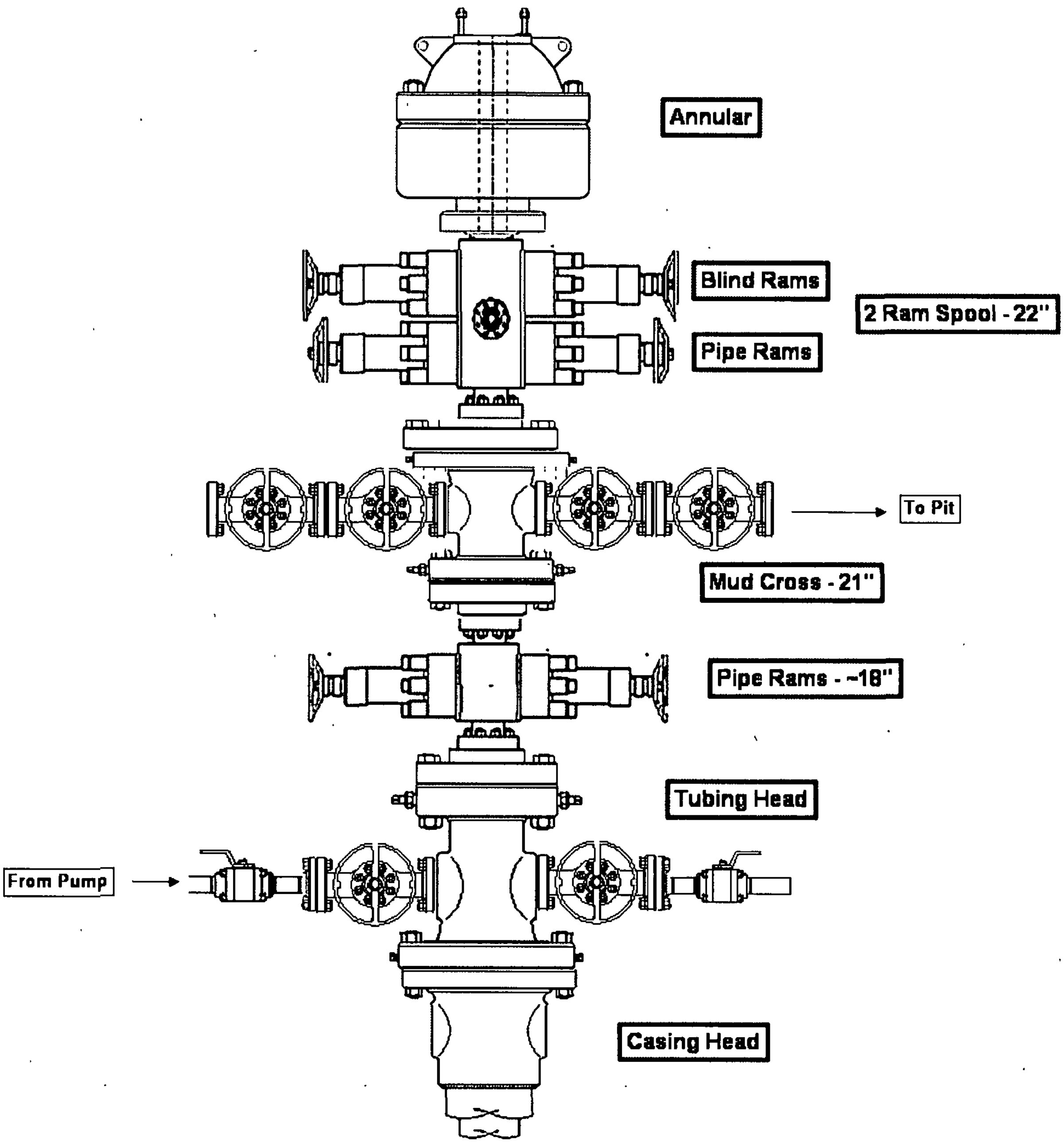
Perforations		Diameter	Shots
8382-8440	4 JSPF	76"	232
8456'-8466'	4 JSPF	76"	40
8476'-8528'	4 JSPF	76"	208
8534'-8600'	4 JSPF	76"	264

Frac Entrada
3828 Bbls 30# XL titrate, 220,000# 20/40 sand, 44 BPM

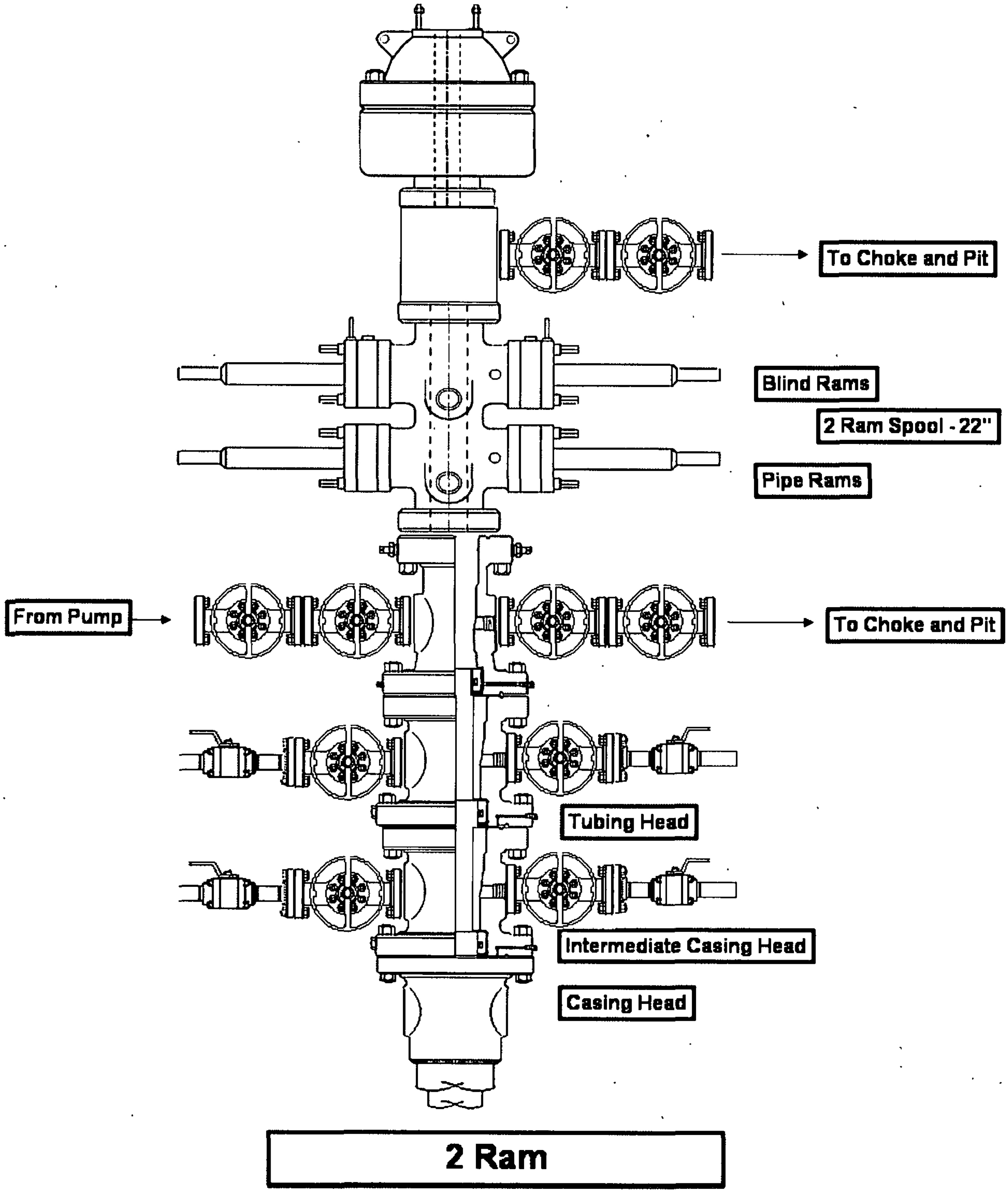
8-1/2" hole
7" 26# N-80 LT&C Inj csg @ 8705'
Stg 1 20 bbls of 2 ppg gel water, 5 bbl spacer water then
110 sx Cl G 35/65 poz cmt, tail w/ 230 sx CL G, partial returns
Open DV, pump 70 bbls CaCl2 mud, 308 bbls 9 3 ppg mud @ 3 3 BPM, returns @ 1 B
Stg 2 20 bbl water spacer, 850 sx Cl G 35/65 poz, tail w/ 75 sx Cl G
job pumped @ 4 BPM, during slurry 1 BPM returns
after 200 bbls slurry, full returns
100 bbls into displ, 1 BPM returns
last 180 bbls displ, no returns
170,000# in slips

PBTD 8620'
TD 8705'

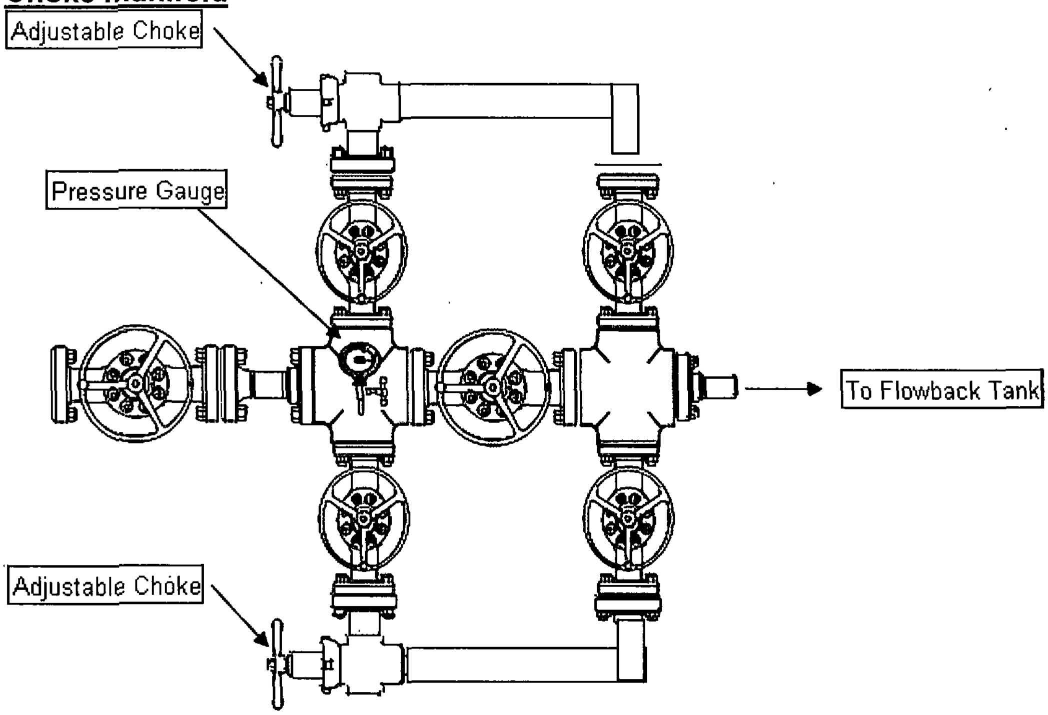
BOP configuration



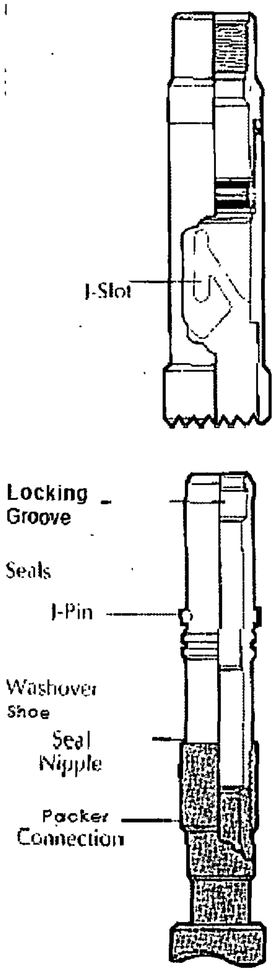
Alternate BOP Diagram



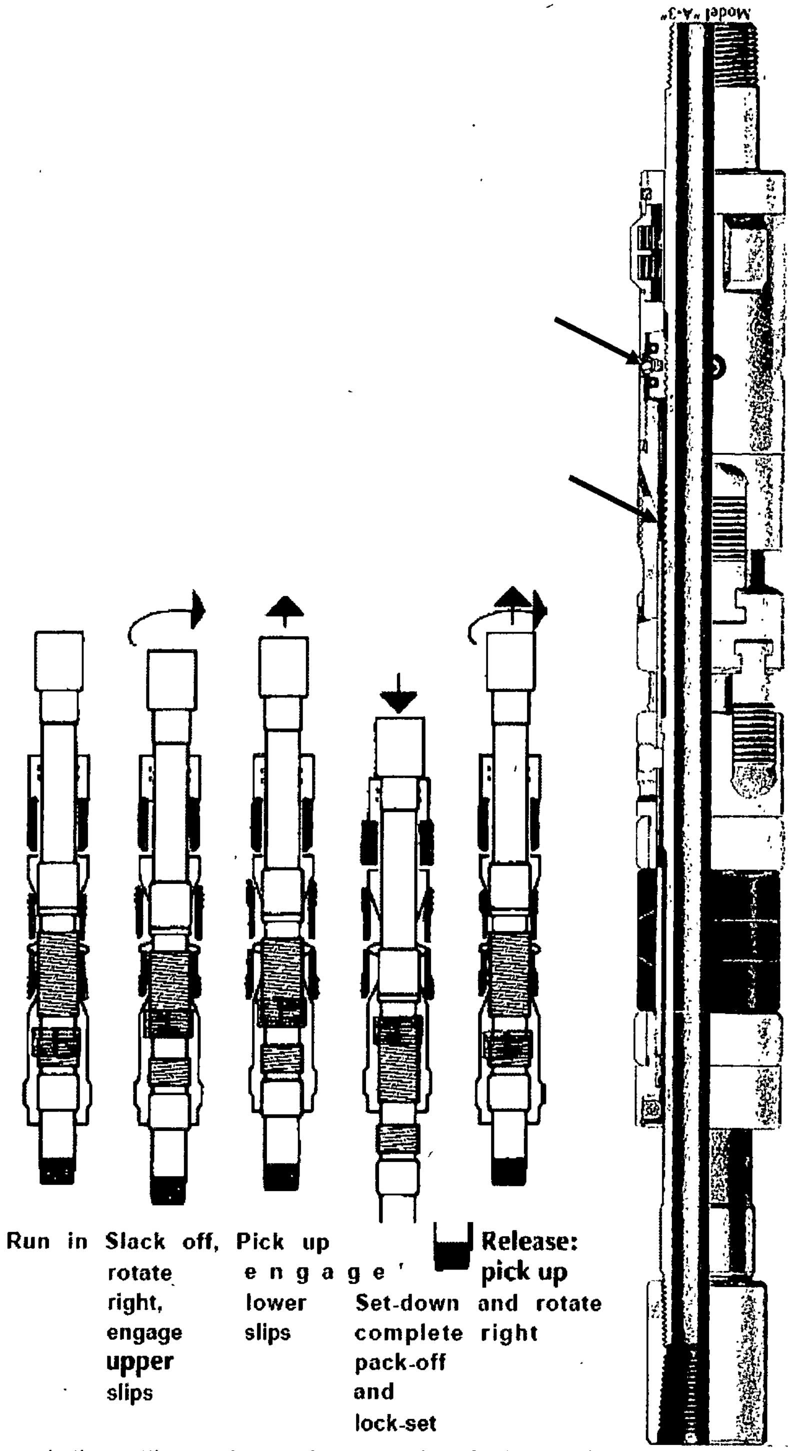
Choke manifold



2", 10K Choke manifold



Baker HEL On-off tool-to unseat, PU rotate to the right (also made to rotate to the left) then set down.



Above is the setting and unsetting procedure for inverted A-2 Lok-set, same as regular:
Packer currently has 44,000# compression on it.
PU to where there is 3000 to 6000# compression on the packer (On-off tool has ~2" of travel, use to find string weight), then rotate to the right from 8 to 10 turns at the tool until the tool moves down the hole, Once a jump is felt, or a loss of string weight continue rotating w/ 3000# on the packer 8-10 turns then begin pulling out of the hole. On inverted packer, threads are switched but unseating procedure is same as regular AL-2.

Red arrow is pointing to the blocks that need to engage the set of threads that the block is currently on.
When packer is set in the inverted position, the blocks are engaging the threads indicated by the blue arrow.