Submit 1 Copy To Appropriate District Office District I – (575) 393-6161 1625 N. French Dr., Hobbs, NM 88240 District II – (575) 748-1283 811 S. First St., Artesia, NM 88210 District III – (505) 334-6178 1000 Rio Brazos Rd., Aztec, NM 87410 District IV – (505) 476-3460 1220 S. St. Francis Dr., Santa Fe, NM 87505	State of New Mexico Energy, Minerals and Natural Resources OIL CONSERVATION DIVISION 1220 South St. Francis Dr. Santa Fe, NM 87505	Form C-103 Revised August 1, 2011

	WELL API NO. 30-025-39804
	5. Indicate Type of Lease STATE ☐ FEE ☒
	6. State Oil & Gas Lease No.
SUNDRY NOTICES AND REPORTS ON WELLS (DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)	7. Lease Name or Unit Agreement Name CENTRAL DRINKARD UNIT
1. Type of Well: Oil Well ☒ Gas Well ☐ Other	8. Well Number 440
2. Name of Operator CHEVRON U.S.A. INC..	9. OGRID Number 4323
3. Address of Operator 15 SMITH ROAD, MIDLAND, TEXAS 79705	10. Pool name or Wildcat DRINKARD

HOBBS OCD

MAY 04 2015

RECEIVED

4. Well Location

Unit Letter: N 959 feet from the SOUTH line and 2519 feet from the WEST line

Section 29 Township 21S Range 37E NMPM County LEA

11. Elevation *(Show whether DR, RKB, RT, GR, etc.)*

12. Check Appropriate Box to Indicate Nature of Notice, Report or Other Data

NOTICE OF INTENTION TO:		SUBSEQUENT REPORT OF:	
PERFORM REMEDIAL WORK ☐	PLUG AND ABANDON ☐	REMEDIAL WORK ☐	ALTERING CASING ☐
TEMPORARILY ABANDON ☐	CHANGE PLANS ☐	COMMENCE DRILLING OPNS. ☐	P AND A ☐
PULL OR ALTER CASING ☐	MULTIPLE COMPL ☐	CASING/CEMENT JOB ☐	
DOWNHOLE COMMINGLE ☐			
OTHER INTENT TO REPAIR POSSIBLE CASING LEAK		OTHER:	

13. Describe proposed or completed operations. (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work). SEE RULE 19.15.7.14 NMAC. For Multiple Completions: Attach wellbore diagram of proposed completion or recompletion.

CHEVRON U.S.A. INC. INTENDS TO INVESTIGATE THE 5 ½" CSG IN THE SUBJECT WELL FOR A POSSIBLE CORROSION BREACH AND IF FOUND, REPAIR, AND RETURN TO PRODUCTION.

PLEASE FIND ATTACHED THE INTENDED PROCEDURE AND WELLBORE DIAGRAM.

DURING THIS PROCESS WE PLAN TO USE THE CLOSED LOOP SYSTEM WITH A STEEL TANK AND HAUL TO THE REQUIRED DISPOSAL, PER THE OCD RULE 19.15.17.

Spud Date: Rig Release Date:

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Denise Pinkerton TITLE: REGULATORY SPECIALIST DATE: 04/29/2015

Type or print name: DENISE PINKERTON E-mail address: leakejd@chevron.com PHONE: 432-687-7375

For State Use Only

APPROVED BY: ______ TITLE Petroleum Engineer DATE 05/04/15

Conditions of Approval (if any):

MAY 05 2015

Chevron

WELL NAME: CDU #440H

API #: 30-025-39804 CHEVNO: MI0722

OPERATOR: Chevron Midcontinent, L.P.

LOCATION: 959'FSL &2519'FWL Sec: 29 Township: 21S Range: 37E

SPUD: 10/4/2010 COMPLETION: 12/30/2011

Wellbore Information:

Surface Casing – 8 5/8", 24#, H-40 set @ 1254' w/ 490 sks (TOC Surf, Circ)
Production Casing – 5 ½", 15.5#, J-55 set @ 6495' w/ stage tool @ 3795' & Cmtd as follows:
1st stage cement - 390 sx Cl "H" from 6495 to 4184' (TOC @ 4184' Oct 8, 2010 CBL)
2nd stage cement – 2000 sx Cl "C" from 3835' (40' fallback below DV) to surface (circ 410 sx to surface)
Window in 5 ½" casing from 6402-6408'
5 ½" PBTD: ~6472' (CIBP below window)

Existing Open Hole Completion:

Drinkard formation: 4 ¾" Lateral from 6405' (center of window) to 9228' MD (6585' TVD)

Tubing String Quantity (Top-Bottom Depth) Desc
198 @(16-6225) J-55 2.875 OD/ 6.50# T&C External Upset 2.441 ID 2.347
1 @(6225-6229) J-55 2.875 OD/ 6.50# T&C External Upset 2.441 ID 2.347
2 @(6229-6294) J-55 2.875 OD/ 6.50# T&C External Upset 2.441 ID 2.347
1 @(6294-6297) Tubing Anchor/Catcher 2.875-
2 @(6297-6360) J-55 2.875 OD/ 6.50# T&C External Upset 2.441 ID 2.347
2 @(6360-6424) J-55 2.875 OD/ 6.50# T&C External Upset 2.441 ID 2.347 Drift - Internal Plastic Ctg-
1 @(6424-6425) Seat Nipple - Heavy Duty (2.875) Cup Type-
1 @(6425-6450) Slotted Mud Anchor 2.875-

Rod String Quantity (Top-Bottom Depth) Desc
1 @(16-42) 1.500 (1 1/2 in.) Spray Metal x 26-
1 @(42-52) 1.000 (1 in.) N-97 x 10 Rod Sub-
76 @(52-1952) 1.000 (1 in.) N-97 (HS) x 25 Rod-
102 @(1952-4502) 0.875 (7/8 in.) N-97 (HS) x 25 Rod-
64 @(4502-6102) 0.750 (3/4 in.) N-97 (HS) x 25 Rod-
12 @(6102-6402) 1.500 (1 1/2 in.) K x 25 Sinker Bar-
1 @(6402-6426) Rod Pump (Insert) (NON-SERIALIZED) - 25-200-H H BM -24-6 (Bore = 2.00)-

PRE-WORK:

1. Complete the rig move checklist. Verify power line route survey with Eunice FMT.
2. Ensure location is in appropriate condition, anchors have been tested within the last 24 months, and power line distance has been verified to determine if a variance and RUMS are necessary.
3. When NU or performing any operation with an open wellhead (Environmental pan, etc.) ensure the hole is covered to avoid dropping anything downhole.
4. Review H_2S calculations in H_2S tab included.
5. Any equipment installed at the wellbore, including wellhead (Inside Diameter), is to be visually inspected by the WSM to insure no foreign debris or other restrictions are present.
6. DO NOT flow back CO_2 (if applicable) to non CO_2 rated vessels!

PROCEDURE:

1. Verify that well does not have surface pressure or ability to flow. If the well has pressure, record tubing and casing pressures on WellView report.
2. MIRU pulling unit and surface equipment.
3. If there is any casing pressure, bleed off casing pressure to tank. If casing is flowing fluid, pump fluid with a constant known weight down casing to perforations and shut in for 30 minutes (or as required) to obtain stabile shut-in surface pressure. Calculate required KW fluid density, weight up and pump kill fluid to kill well as applicable. If kill was required, monitor casing side pressure for 30 minutes to ensure it is dead before proceeding further.

   Prior to TOH with rods, consult ALCR and Production Engineer to verify final rod & tubing design to be run at the end of the workover. Also ALCR to obtain a line on an ESP, cable and VSD capable of pumping between 2000 to 3000 bfpd in case well is found to have integrity and water increase is result of injected water breakthrough via the Drinkard high perm zone and higher pump rates are required to draw FL down to restore oil production.

4. Remove stuffing box and lay down polished rod. NU rod BOP and stripper. Unseat pump and assure well is under control from tubing side. Monitor tubing side for 30 minutes to ensure it is dead.
5. TOH with rods and pump (Lay down rods if final design hasn't been confirmed with ALCR and/or Production Engineer). Examine rods for wear/pitting/scale/paraffin. If paraffin is observed, do not hot water treat well to avoid pumping any melted paraffin downhole where it could coat perforations – send affected tubing and rods off site for necessary cleaning. If excessive paraffin exists in tubing and TOH is not safe or environmentally friendly, contact workover engineer for further guidance.
6. Monitor well for 30 minutes to ensure it is dead.
7. ND rod BOP/stripper and wellhead. Check to see if tubing was landed with a hanger and which type.

8. If mandrel hanger was landed in tubing head, install BPV through tubing and seat in tubing hanger. Strip over tubing with **Chevron Class II configured 7-1/16" 5M** remotely-operated hydraulically-controlled BOP configured with 2-7/8" pipe rams over blind rams and flange up to tubing head. NU Environmental protection pan and rig up rig floor. Test BOP pipe rams and blind rams to 250 psi low pressure test for 5 min / 1000 psi high pressure test for 10 min. Record test pressures in WellView. Remove BPV, unset packer and TOH to LD tubing hanger.

9. If hinged slip-type hanger used, remove wellhead top nut, top packing ring and packing rubbers above slips and install 7 5/8", 8rd (or as required) screw on x 7 1/16", 5M companion flange to head. NU **Chevron Class II configured 7-1/16" 5M** remotely-operated hydraulically-controlled BOP configured with 2-7/8" pipe rams over blind rams. NU environmental protection pan. RU floor, unseat hanger, release TAC and POOH with 1 joint 2 7/8" tubing. PU 5 ½" test packer for 5 ½", 15.5# casing and TIH with test packer to approximately 25', set packer and test BOP pipe rams and blind rams to 250 psi low pressure test for 5 min / 1000 psi high pressure test for 10 min. Record test pressures in WellView. Release and LD test packer and make up original top joint of 2 7/8" tubing back to tubing string. **(Day 1 complete)**

   - Keep the charted test of the BOP supplied by the vendor for the entire job.

10. Mobilize tubing inspection equipment and personnel. PU 1 joint 2 7/8" tubing and TIH to CIBP at approximately 6472' to tag for fill and record in WellView ***(TAC 6294 – 97', casing window from 6402 – 6408', EOT 6450', PBTD (CIBP) ~6472')***. Rig up vertical scan tool, POOH scanning 2 $^7/_8$" production tubing. Keep (stand back if able) yellow band only (25% or less wall loss), LD all non-yellow band joints. Rope off stood back production tubing to keep it separate from workstring. Send TAC for inspections and redress and order replacement SN and any other required equipment.

    Strap production tubing and equipment out of hole to verify depths and note footage and well equipment location in WellView. Send tubing scan report to robert.hall@chevron.com.

    Assure that any required replacement production tubing (regular and IPC), rods, new pump and ancillary pump equipment (i.e., SN, sand separator etc.) have been ordered and will be available for re-completion. Re-confirm rod and tubing design with ALCR prior to purchasing new equipment.

    Caliper elevators and tubular handling equipment EACH DAY prior to handling tubing/tools. Note in JSA when and what items are calipered within the task step that includes that work.

Testing Casing Integrity

11. Mobilize ~6700' of 2 7/8", 6.5#, L-80, EUE-8rd workstring to location for pressure testing work.

12. PU and RIH w/ full-open 4 ¾" workover bit and 5 ½" casing scraper crossed over to 2 7/8" workstring to 3800' and then slowly work in hole with bit and scraper through San Andres formation and down to 6300' (102' above casing window) while carefully working scraper across interval 3800 – 6300'. POOH with bit and scraper. Note that casing is less than 5 years old. **(Day 2 complete)**

13. If any fill was tagged higher 6472' (CIBP) in **Step 10** that could be obstructing the lateral window, pick up 2 7/8" sand pump (Bulldog Bailer) with appropriate cavity spacing between valves (to accommodate fill volume to be removed) – use 4 3/4'" WO bit on bottom of bailer if bit was full opening. TIH and clean out fill as necessary to 6472'.

14. If bailer run was required, TOH, unload and LD bailer. Remove seals in mud bucket when breaking connections at check valves.

15. Mobilize Archer Wireline. Conduct pre-run calibration checks on 3 5/8" OD 56-arm multi-finger caliper and magnetic thickness tool (MFC/MTT). Rig up lubricator containing same and RIH to 5950' and pull short strip to tie log into short casing joint from 5929+ to 5908' as indicated on Gray Wireline CBL/VDL/GR/CCl dated Oct 8, 2011. Run down to 6370' and run MFC/MTT log from 6370' to surface with MTT turned off at ~1254' (base of surface casing where MTT will run into interference). Run repeat across any interval that shows corrosion or potential full penetrations. Note should see stage tool at 3792 - 3794'. Assure that a copy of the processed log is immediately transmitted to the office Workover and Production engineers for evaluation and recommendations/refinements for casing pressure testing operations. **(Day 3 complete)**

Note: If results of casing inspection logging indicate significant thinning of casing wall adjacent to uncemented casing interval in addition to corrosion penetrations that suggest a potential fix on the current penetration could result in a short-lived well repair, well could become candidate for P&A status – consult with office after results of casing inspection logging (Step 15) and pressure testing (Steps 17- 18) are available.

16. Mobilize 5 ½" test packer and RBP, MIRU hydrotesters. PU 5 ½" RBP, 5 ½" test packer (w/ 2.25" frac hardened profile below packer) and RIH on 2 7/8", 6.5#, L-80, EUE-8rd workstring. Hydrotest workstring and packer to 6000 psi while TIH to ~6370' (RBP location ~32' above window). If workstring tested successfully, release hydrotesters from location. If cement bond log with CCL/GR available, adjust setting depth as required to be sure that RBP and packer is not being set across a casing connection.

    Assure standby test packer and RBP are available in case the initial equipment loses seal ability while in use.

17. Set RBP at approximately 6370' and release from RBP. Set packer at approximately 6360' (or as required for blank pipe test), top off tubing with appropriately weighted brine and conduct blank pipe test down workstring against RBP to 500 psi to assure RBP has pressure integrity. Bleed off test pressure, release test packer and attempt to load casing with appropriately weighted brine and test casing system down backside to 500 psi. If casing does not load or test, pull uphole to 6000' (or as required based on results of casing inspection logging) and set packer. Top off tubing with appropriately weighted brine and conduct pressure test down workstring against RBP to 500 psi to test integrity of casing between packer and RBP. Bleed off test pressure and repeat pressure tests at 5000', 4000', 3000' etc. until the casing leak has been identified.

18. If a leak point has been identified via pressure testing down workstring, load backside and pressure test backside to confirm integrity of casing above leak.

19. Once backside integrity has been confirmed above the casing leak, release test packer, install test gauge to backside, close pipe rams and conduct injection test down workstring at 1, 2 and 3 bpm while monitoring backside for pressure increase and do not exceed 500 psi pressure increase on backside. **(Day 4 complete)**

Testing Casing Integrity – Decision Point

Note: Use data from casing inspection log to refine pressure test depths especially if corroded or damaged casing is evident from the log. If casing damage is evident and metal thinning is extensive adjacent to uncemented casing across San Andres, Workover and Production Engineers will advise on remaining direction of workover up to and including well T/A or P&A – do not proceed any further to attempt repairs until advised from office to do so.

If the results of casing inspection logging and casing pressure testing indicate the casing to have integrity, then it must be assumed that the source of the water increase is breakthrough from injection operations. If this is the case, then the well can either be recompleted with the tubing and rod pump located further uphole to pump off the fluid column and skim the top oil or use a larger diameter tubing pump to attempt to pump off the well.

Casing Integrity Alternative – Verification of Good Casing (Likely water breakthrough)

20. If full casing integrity was demonstrated in Step #17, proceed to **Section: Running Production BHA**. (Starting at Step #29.)

Casing Integrity Alternative – If leaking in Grayburg/San Andres

21. Once leak has been identified, clearance from office to proceed on with repairs has been issued, an injection rate obtained and assuming leak was found in the San Andres adjacent to our uncemented interval, release test packer and RIH to RBP at 6370'. Precautionary wash down to top of RBP and circulate for 10 minutes. Then engage, equalize and release RBP and pull uphole to base of good cement below San Andres at 4240' and set RBP. Release from RBP and set test packer at 4230', top off workstring and conduct blank pipe test to 500 psi to assure integrity of RBP. Release test packer and POOH LD test packer. ***Note depths in this procedure will need to be adjusted if a leak is found elsewhere in the casing system.***

22. RIH with OE WS to 4000' and dump 20' of sand on top of RBP. Wait 1 hour for sand to settle and RIH with OE WS and tag top of sand – adjust as required to assure minimum of 20' of sand coverage over RBP without covering leak. POOH with OE WS.

23. Mobilize cementers and test cement blend and mix water for chloride compatibility. PU and RIH with 5 ½" cement squeeze retainer on 2 7/8" workstring to 100' above identified casing leak point and set retainer. Pressure test backside to 500 psi to assure pressure integrity above retainer, then release from retainer and sting back in. Establish injection rate into leak with fresh water and assuming high leak rate was identified in Step 19, blend and pump 100 barrels of Thixotropic cement down workstring and displace with fresh water to squeeze retainer. Unsting from retainer and reverse two (2) tubing volumes of fresh water to assure any cement has been cleared from workstring. SDFN while WOC with workstring above retainer. **(Day 5 complete)**

Note: If casing leak is identified and depending on the magnitude of the leak identified from injectivity testing, the squeeze cementing procedure may be modified by balancing a Class C cement slurry across the leak, pulling out of the slurry and conducting a hesitation squeeze to lock up the leak.

24. The next morning, attempt to sting back into retainer and pump down workstring to determine if cement below retainer has locked up above the damaged casing interval – do not exceed 500 psi if WS is pressuring up. If it appears cement has locked up, unsting from retainer and trip for 4 3/4" bit and BHA. If able to pump into retainer, execute another squeeze operation with cement type and volume dictated by latest pump rate and pressure. **(Day 6 complete if re-squeeze is required)**

25. PU and RIH with full open 4 ¾" workover bit and eight (8) 3 ½" OD x 2" ID collars crossed over to 2 7/8", 6.5#, L-80, EUE-8rd workstring to top of retainer. Rig up power sub/swivel, stripper head and reversing unit. Drill out (reversing) cement retainer and cement until breakthrough or hit top of sand above RBP while using gel sweeps as required to clean the hole – do not wash off sand on top of RBP at this time. Reverse well clean and report if having full or partial returns, trip above damaged casing then close in and gradually pressure test squeezed casing to 500 psi in 100 psi increments for 10 minutes at each pressure step and 30 minutes if 500 psi successfully achieved. If well not holding pressure, observe and report injection rate at each pressure step to office so that the next squeeze operation can be planned. POOH and LD drill collars. **(Day 7 & 8 complete if a re-squeeze and extra drill out required)**

    Note: If while drilling cement below the squeeze retainer and reversing, we begin to loose circulation near the suspected damaged casing interval, switch to conventional circulation and continue drilling while circulating returns and cuttings into the formation adjacent to the damaged casing to try to plug it up somewhat to help in implementing the next squeeze attempt.

26. If casing held test pressure at 500 psi, pick up RBP retrieving overshot with SN (for swab negative test on casing) and TIH on 2 7/8" WS to within 50' of sand on top of RBP. Circulate well with clean fluid, close in backside and gradually pressure test casing to 500 psi and chart test for 30 minutes – report results in Wellview. Bleed off test pressure and rig up to swab well. Swab FL down approximately 1000 feet to impose negative 500 psi on squeezed interval and monitor for 30 minutes. Then run swab back down to verify no fluid entry which constitutes a successful negative test and report results in WellView.

    Before and during swabbing: *Visually inspect sandline for frays, excessive rust, bird's nests, kinks, etc. and replace line as needed.*

    Follow swab reporting template found on WellView example well – JIMENEZ 'A' 001 – Chevno = AA0000

27. After completion of positive and negative testing operations, check tubing and backside pressures to assure no additional well control fluid is required prior to opening pipe rams. If pressures are 0 psi on both sides, open pipe rams, rig up for reversing operations, establish reverse circulation and wash down to top of sand above RBP. Wash sand from top of RBP using gel sweeps as required. When at top of RBP continue to reverse circulate to clear residual sand for at least two (2) workstring volumes then stop reversing, engage RBP, equalize, release and TOH with WS. LD RBP. **(Day 9 complete)**

28. Trip back in hole with OE workstring to top of CIBP at 6472' to make sure adequate rathole still exists below casing window. If sufficient rathole exists below window, TOH LD workstring.

Running Production BHA

Note: If casing demonstrates integrity from logging and pressure testing, injected water breakthrough is most likely the cause of the increased water production and high fluid level. Consult with Production Engineer, Workover Engineer, and ALCR for consideration of running larger diameter tubing pump instead of the conventional insert rod pump indicated below.

29. Re-mobilize and RU hydrotesters. PU production BHA:

    2 7/8" EUE-8rd HD Bull Plug
    1 new jt 2 7/8" 6.5# J-55 EUE-8rd Slotted MA
    1 new 2 7/8" EUE-8rd HD Pump SN
    2 new jts 2 7/8" 6.5# J-55 EUE-8rd tbg (TK-99 IPC)
    2 new jts 2 7/8" 6.5# J-55 EUE-8rd tubing
    1 new 2 7/8" x 7" TAC

    TIH with 198 jts (or as required) 2 7/8" 6.5#, J-55 EUE-8rd tubing while hydrotesting original/replacement production tubing and ancillary equipment to 5,000 psi (80% of adjusted burst rating with nominal 75% remaining wall thickness yellow band inspection criteria). Space out for EOT @ ~6450', SN @ ~6430' and TAC @ ~6285' ***(or as per ALCR Recommendations). (Day 10 complete)***

30. ND BOPE, NUWH.

31. Install rod BOPE and stripper. TIH with new pump and original/replacement rods ***(Per ALCR Rod design)***

    Contact appropriate Field Specialist to remove locks.

32. ND Rod BOP and stripper, space out, install stuffing box, polished rod, horsehead and bridle. Check pump action with pumping unit.

33. Clean location, RDMO PU. Notify ALCR and production personnel workover has been completed. Complete Workover Ownership Form, turn well back to production (contacts on first page). ***Make sure to send completed Workover Ownership Form to robert.hall@chevron.com. (Day 11 complete)***

HORIZONTAL WELL DATA SHEET

Field: Central Drinkard Unit

WELL NAME: Central Drinkard Unit # 440H

Formation: Drinkard

LOC: 959' FSL, 2519' FWL	SEC: 29	GL: 3,467'	CURRENT STATUS: Producing oil well
TOWNSHIP: 21S	COUNTY: Lea	KB to GL: 16'	API NO: 30-025-39804
RANGE: 37E	STATE: NM	DF to GL:	Chevno: MI0722

Cost Center: UCU410400
GPS: NAD27
N 32.4451598, W -103.1850348

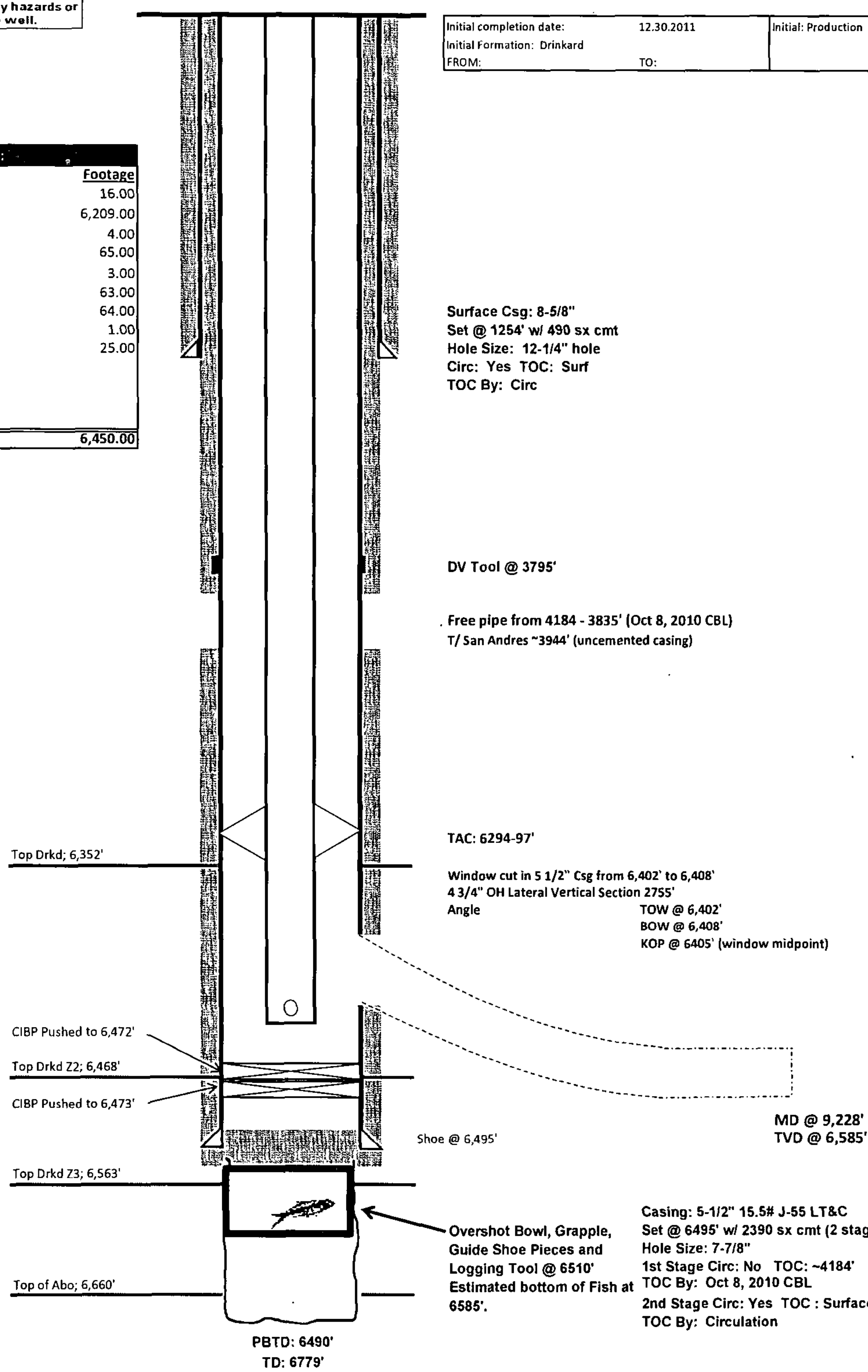
This wellbore diagram is based on the most recent information regarding wellbore configuration and equipment that could be found in the Midland Office well files and computer databases as of the update date below. Verify what is in the hole with the well file in the Eunice Field Office. Discuss w/ WEO Engineer, WO Rep, OS, ALS, & FS prior to rigging up on well regarding any hazards or unknown issues pertaining to the well.

Current
Wellbore Diagram

Initial completion date:	12.30.2011	Initial: Production
Initial Formation: Drinkard		
FROM:	TO:	

Tubing Detail:

#Jts:	Size:	Footage
	KB Correction	16.00
198	2-7/8" tbg 6.5# J-55	6,209.00
1	2-7/8" Tubing sub 6.5# J-55	4.00
2	2-7/8" tbg 6.5# J-55	65.00
1	2-7/8" TAC	3.00
2	2-7/8" tbg 6.5# J-55	63.00
2	2-7/8" tbg 6.5# J-55 IPC	64.00
1	2-7/8" Pump SN	1.00
1	2-7/8" Slotted Mud Anchor	25.00
208	Bottom Of String >>	6,450.00



Surface Csg: 8-5/8"
Set @ 1254' w/ 490 sx cmt
Hole Size: 12-1/4" hole
Circ: Yes TOC: Surf
TOC By: Circ

DV Tool @ 3795'

Free pipe from 4184 - 3835' (Oct 8, 2010 CBL)
T/ San Andres ~3944' (uncemented casing)

TAC: 6294-97'

Window cut in 5 1/2" Csg from 6,402' to 6,408'
4 3/4" OH Lateral Vertical Section 2755'
Angle
TOW @ 6,402'
BOW @ 6,408'
KOP @ 6405' (window midpoint)

Overshot Bowl, Grapple, Guide Shoe Pieces and Logging Tool @ 6510' Estimated bottom of Fish at 6585'.

Casing: 5-1/2" 15.5# J-55 LT&C
Set @ 6495' w/ 2390 sx cmt (2 stages)
Hole Size: 7-7/8"
1st Stage Circ: No TOC: ~4184'
TOC By: Oct 8, 2010 CBL
2nd Stage Circ: Yes TOC : Surface
TOC By: Circulation

Updated: 1/22/2015

By: R.F. Bielenda