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 July 18, 2013

WELL API NO. 30-015-44388
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: Remuda Basin SWD

1. Type of Well: Oil Well ☐ Gas Well ☒ Other SWD

8. Well Number 001

2. Name of Operator: XTO Energy Inc.

9. OGRID Number 5380

3. Address of Operator: 6401 Holiday Hill Rd, Midland TX 79705

10. Pool name or Wildcat: SWD;Devonian

4. Well Location
Unit Letter O : 1320 feet from the FSL line and 1980 feet from the FEL line
Section 25 Township 23S Range 29E NMPM County Eddy

11. Elevation (Show whether DR, RKB, RT, GR, etc.) 3061'

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 ☐			
CLOSED-LOOP SYSTEM ☐			
OTHER: ☐		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.

XTO Energy Inc. respectfully submits this sundry for approval to Plug and Abandon this well per the attached 2 phase procedure, Proposed WBD, as well as Current WBD.

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 Kristen Houston TITLE Regulatory Analyst DATE 04/12/24

Type or print name Kristen Houston E-mail address: kristen.houston@exxonmobil.com PHONE: (432-894-1588

For State Use Only

APPROVED BY:______ TITLE______ DATE______
Conditions of Approval (if any):

Abandonment Procedure

Work Scopes

1) POOH and lay down tubing
2) Set cement plugs up to 7" liner top (Phase 1). Shut down and monitor casing pressure
3) If Production Casing and Intermediate Casing Pressure do not alleviate (can't bleed down to zero). Restart P&A operation to complete P&A (Phase 2)
   NOTE: Should Production Casing and Intermediate Casing Pressure can be alleviated (bleed down to zero). SWD Permit will file to re-enter the well. Separate procedure will be filled.

Well Condition

1) Well has sustained annulus pressure on 7-5/8" production casing (1100 psi) and 9-5/8" intermediate casing (600 psi, AKA Int CGS 2). No pressure observed on surface casing (AKA Int 1). The intermediate casing pressure has been decreasing the past two years.
2) No dated record of the last MIT
3) Tubing (IPC) was last replaced in October 2020 - However, the integrity had not yet confirmed recently
4) Well was last injected in April 21, 2023

Special Considerations:

The source of pressure on the 7-5/8" x 9-5/8" intermediate and 7-5/8" production casing is believed to below the intermediate casing shoes at 10,845' MD and above the TOC at 13,350'. Procedure developed incorporated all available information and previous works with a small hope to savage the wellbore and return well SWD. While the procedure do not guarantee success of savaging the wellbore, it is certainly intended to plug the well, exceeding the regulatory requirement. Special attention is required to monitor all annulus pressure throughout the job. All annulus pressure must be recorded and reported after each cement plug.

Permit: Verify Notice of Intent to Plug approval. Review procedure with any condition of approval

Phase 1 Procedure:

Note: Throughout the operation, be sure to record and report pressure build up overnight for monitoring progress

1) Visit location. Asses and clear area. Check wellhead specs and condition. Send BOP/WH provider to verify if required. Enter/update WH specs in WV. Check anchor tags & confirm anchor tested if use. Notify SWD operator/foreman the plan to MIRU WO unit
2) Create a new group text with the contacts listed in contacts section. Please name group text Well Name and Job Description
3) Complete JSA & have safety meeting. Fill out pre-job checklist and safeguard register. Complete lock out/tag out procedures on all energy sources. Record and document all casing pressure in WV. Adjust KWF & well-pressure-class category as necessary

4) MIRU WO unit and auxiliary equipment. Rig up reverse unit/pump, lay lines, hook up to tubing (flow tee) & casing, and HI/LO pressure test lines to 300/4500 psi 10 minuts each.

5) MIRU WLU. RIH CCL+GR and tubing perforator. Shoot holes above packer
NOTE: Record tubing and casing pressure immediately before and after perforating

6) Kill well by flushing Tubing-Casing Annulus and then Tubing with 10# KWF per standard SOP manual. Monitor "no pressure" for 30 minutes and confirm kill.
NOTE: Tubing X Casing Annulus Capacity *1.25 – 311 BBLS - Pump at least 3.0 BPM
NOTE: Tubing Capacity (to packer) + Openhole *1.25 – 439 BBLS - Pump at least 3.7 BPM
NOTE: May bleed off gas pressure and/or flush tubing first before perforating for ease of RU WL and RIH with gun to perforate tubing

7) Lubricate 2-way check into tubing head. Pressure test 2-way check to ensure it holds. ND injection tree
NOTE: Inspect tubing hanger thread condition. Take photos for documentation
NOTE: Tubing Hanger specs: Cactus Wellhead - WG-T-EN,7,11 X 5-1/2 BC BOX BTM & TOP,W/5 HBPV THD,DOVETAIL GROOVES,17-4PH SS,TEMP PU, MATL FF-0,5, PSL2, PR1

NOTE: A casing spear should be considered should landing thread compromised
NOTE: Keep the hanger and Christmas tree on location for now. Will send in Christmas tree to Sonic (Jeff Barnett) for service and testing at later date

8) NU 10K x 5K DSA, 5K Class B BOPs with VBR 3-1/2” to 5-1/2”. Test according to the Completion and Well Work Standard Operating Procedures

9) Remove 2-way check. Back out hanger lock pins.

10) Straight pull 25 pts over-pull (test pulling tubing)

11) Slack back ~5 pts over-pull, rotate 8-10 round to release from Weatherford Dual Bore Permapak Packer
NOTE: Tubing string air weight is **238K lbs,** calculated buoyancy weight with **10 ppg fluid is 202K lbs**.
NOTE: Tubing was hanged with 30K compression on packer
NOTE: If unable to release from packer, RU WLU. Make GR and tubing free point. RIH CCL with radial cutting tool to cut pipe body just above the packer (Further guidance to be provide based on free-point and CCL). Ensure the **tubing in tension** when making cut
NOTE: It is highly recommended to have casing spear and WLU (with tubing cutter and free-point tool) on location as contingencies for bad tubing hanger threads and the lack of success rotating out from the packer

12) TOH & LD 5-1/2” & 4.5” tapered tubing string. Send the tubing string to yard
NOTE: Visually inspect pins for IPC damage while TOOH. Take photos for documentation
NOTE: Visually inspect tubing for any scale. If scale is found, contact ChampionX reps for sampling
NOTE: Inspect elastomer seals of anchor latch for signs of damage when pulled. Send assembly back to Weatherford for inspection

13) RDMO over-sized WO rig
NOTE: Discuss with Rig Supt whether BOP on location and/or whether to land tubing hanger with BPV to secure the well

14) MIRU P&A rig unit and auxiliary equipment. Rig up reverse unit/pump, lay lines, pressure test lines to MAWP
NOTE: RU BOP if removed on previous step. Test according to the Completion and Well Work Standard Operating Procedures

15) Kill well as per with 10 PPG at least 6 BPM
NOTE: Casing Capacity + Openhole *1.25 – 851 BBLS

16) MU and RIH casing scrapper on 2-7/8" work string to packer . POOH

17) RU WL and lubricator (Category 1), Lo/Hi pressure test 300/2000 psi for 10 minutes each, and RIH with CIBP. Set plug above packer (or above cut pipe). POOH

18) Pressure test casing and plug to 500 psi
NOTE: This is done to confirm casing/liner integrity
NOTE: The purpose is to confirm pressure seal before setting cement plug, hence doing away with the need of tagging the first cement plug

19) RU cementing unit. Mix at least 25 sacks of Class H (~5 BBL, 131'), Spot cement above CIBP
NOTE: Tagging of formation plug is not necessary as a solid base is established and confirmed on previous step

20) Circulate well with 13.5 PPG mud. POOH
Note: Well was drilled with mud weight as high as 13.4 PPG

21) RU WL and Category 2 lubricator, Lo/Hi pressure test to 300/4500 psi for 10 minutes each, and RIH with 2' perf gun (4SPF Spiral) and perforate at 13,174'.
NOTE: This plug is designed to isolate the Morrow Formation (Formation Top @ 13,124' MD)

22) Establish injectity at 500 psi, 1000 psi, and 1500 psi
NOTE: The injectivity test will confirm injectivity before setting cement retainer and will guide squeeze pressure and guide any additional cement volume to mix

23) MU and RIH w/ with cement retainer on work string. Set CICR at 13,134' MD (40’ above perf set)

24) Partially sting out retainer to close retainer valve. Pressure test tubing to 2000 psi. Sting back into retainer and reconfirm injectivity

25) RU cementing unit. Mix 85 sacks of Class H (~16 BBL for ~232' cmt plug). Perform cement block squeeze 8 bbl below retainer
NOTE: Estimate ~34 sacks to exit casing 8 sacks inside casing and below CICR
NOTE: Do not squeeze above frac pressure

26) Sting out the cement retainer and spot remaining 8 BBL above the retainer (~192' cmt above retainer)
NOTE: Do not over flush tubing volume when displacing cement.

NOTE: Mix and add excess if needed to ensure adequate cement above plug

27) PU and Reverse clean. POOH

28) Wait for at least 4 hours for cement to cure before tagging

29) RU WL and Category 2 lubricator, Lo/Hi pressure test to 300/4500 psi for 10 minute each, and RIH with 2' perf gun (4SPF Spiral). Tag TOC and record/Report TOC of the prior plug. PU and perforate at 11,700'. POOH

NOTE: This plug is designed to create additional barrier and prevent any gas migration (not target to isolate any particular formation, though it can be)

30) Repeat step 22-28 with 80 sack of Class H (15 BBL for 217' cement plug). Squeeze 40 sacks (7.7 BBL) below plug and spot 39 sacks (7.4 BBL, 177') above CICR

31) RU WL and Category 2 lubricator, Lo/Hi pressure test to 300/4500 psi for 10 minutes each, and RIH with 2 X 2' perf gun (4SPF Spiral). Tag TOC and record/Report TOC of the prior plug. PU and perforate at 10,895' & 10,580'. POOH

NOTE: This purpose of this 315' circulating plug is designed to seal off casing shoe, the liner top, and the Wolfcamp Formation

NOTE: The perf depth was picked using Cement Bond Log acquired on 11-Oct-2020. Be sure to corelate to the log when performing perforation.

32) Establish injectivity at 1000 psi, 1500 psi, and 2000 psi

NOTE: The injectivity test will confirm injectivity before setting cement retainer and will guide squeeze pressure and guide any additional cement volume to mix

33) RIH w/ with cement retainer. Set CICR at 10,855 (40' above the lower perf)

34) Partially sting out retainer to close retainer valve. Pressure test tubing to 2000 psi. Sting back into retainer and attempt to establish circulation between both sets of perfs

NOTE: observe solid content on returned fluid, circulating rate and pressure, and mark tubing depth

NOTE: Pay special atttention to fluid level and amount of loss. Adjust mud weight if need to achieve static condition with fluid level at surface before pumping cement

35) Sting out, circulate down tubing at maximum pump rates until clean returns

36) String back and land in retainer and circulate clean at same pump rate step 34 above
(confirm by tubing depth marker and circulating pressure)

37) RU cementing unit. Mix 208 sacks of class H (~39 BBL), Circulate 49 sacks (~9 BBL) below CICR with casing valve open for 315' plug outside 7" casing

NOTE: If formation easily taking fluid (step 32) consult with engineer to mix more than 208 sacks

38) Close BOP & casing valve to stop taking return and squeeze extra 20 sacks (4 BBL) of cement behind 7" liner
NOTE: Do not squeeze above frac pressure

39) Sting out and spot remaining 139 sack (~26 BBL) of cement for at least 605' of cement above the cement retainer
NOTE: The TOC be at above 10249 (or least 50' above the top of Wolfcamp Formation at 10,299)

40) POOH to 10500'. Reverse clean. Close BOP and pump apply 200 psi (or no more than 1 bbl which ever come first) to 7-5/8" casing while WOC

NOTE: Do not bleed down the intermediate casing pressure until cement cured

41) Circulate out mud with fresh water
NOTE: This allow negative testing to assess plug/casing integrity during the monitoring period

42) POOH and LD work string

43) Land tubing hanger and re-install Christmas tree to suspend operation

44) RDMO and suspend P&A operation - End of Stage 1

NOTE: Monitor casing pressure buildup up to 3 months to assess any impact to casing and intermediate casing pressure. If casing pressure and intermediate casing pressure alleviated, P&A operation will be suspended and well re-entering will be evaluated for SWD (only after additional permit approval from NMOCD). If casing and intermediate casing pressure sustained, P&A operation will re-started promptly with the rest of cement plug

Phase 2 Procedure:

45) Complete JSA & have safety meeting. Fill out pre-job checklist and safeguard register. Complete lock out/tag out procedures on all energy sources. Record and document all casing pressure in WV.

46) MIRU WO unit and auxiliary equipment. Rig up reverse unit/pump, lay lines, pressure test lines to MAWP, & hook up to tubing (flow tee) & casing.

47) Bleed off any casing pressure. Monitor "no pressure" for 30 minutes and confirm well static

48) ND Christmas tree and NU 10K x 5K DSA, 5K Class B BOPs. Test according to the Completion and Well Work Standard Operating Procedures

49) PU work-sting and RIH open end

50) Tag to confirm the TOC no lower than 10,249'. Document and report the tag depth. Top-up w/ Class H cement if TOC found lower than 10,249' MD

51) PU. Mix 50 sacks of Class H cement and set a balance cement plug from 8,702'-8,516'
NOTE- The purpose of cement to plug to keep the distance between two plugs to less than 3000'
NOTE- Tagging is not required

52) PU. Mix 47 sack of **Class H** cement and set a balance cement plug from 6,849'-7,019' MD
NOTE - The purpose of this cement plug is to isolate the top of Bone Spring Formation (Top of BS Formation @ 6,969')
NOTE- Tagging is not required

53) PU. Mix 27 sack of **Class C** cement and set a balance cement plug from 3,677'-3,800' MD
NOTE - The purpose of this cement plug is to isolate the DV tool on 9-5/8" casing
NOTE- Tagging is required

54) RU WL and Category 2 lubricator, Lo/Hi pressure test to 300/2,500 psi for 10 minutes each, and RIH with 2 X 2' perf gun (4SPF Spiral). Tag TOC and record/Report TOC of the prior plug. PU and perforate at 3,338' & 3,200'. POOH
NOTE: This circulating plug is designed to isolate Top of Delaware Formation, seal off 13-3/8 casing shoe, and the base of Salt

55) Establish injectivity at 1000 psi, 1500 psi, and 2000 psi
NOTE: The injectivity test will confirm injectivity before setting cement retainer and will guide squeeze pressure and guide any additional cement volume to mix

56) RIH w/ with cement retainer, set 40' above the lower perf set

57) Partially sting out retainer to close retainer valve. Pressure test tubing to 2000 psi. Sting back into retainer and attempt to establish circulation between both sets of perfs
NOTE: observe solid content on returned fluid, circulating rate and pressure, and mark tubing depth

58) Sting out, circulate down tubing at maximum pump rates until clean returns

59) String back and land in retainer and circulate clean at same pump rate step 57 above
(confirm by tubing depth marker and circulating pressure)

60) RU cementing unit. Mix 120 sacks of class H (~28 BBL), Circulate 41 sacks (~10 BBL) below CICR with casing valve open for 138' plug outside 7" casing
NOTE: If formation easily taking fluid (step 55) consult with engineer to mix more than 120 sacks

61) Close BOP pipe rams & casing valve to stop taking return, squeeze extra 16 sacks (4 BBL) cement into formation
NOTE: Do not squeeze above frac pressure

62) Sting out and spot remaining 63 sack (~15 BBL) of cement for ~285' of cement above the cement retainer

63) PU 2950'. Reverse clean. Close BOP and pump apply 200 psi (or no more than 0.5 bbl which ever come first) to 7-5/8" casing while WOC

NOTE - Do not bleed down the intermediate casing pressure until cement cured

64) RBIH and tag to confirm TOC above 3,013' MD. Top-up if found cement top below 3,013'

65) Confirm zero pressure (No bubble) for all casing. Consult with engineer if any doubt

65) PU. Mix 95 sack of **Class C** cement (22 BBL) and set a balance cement plug from 467' MD to surface
NOTE - The purpose of this cement plug is to isolate the Top of Salt and Surface Cap

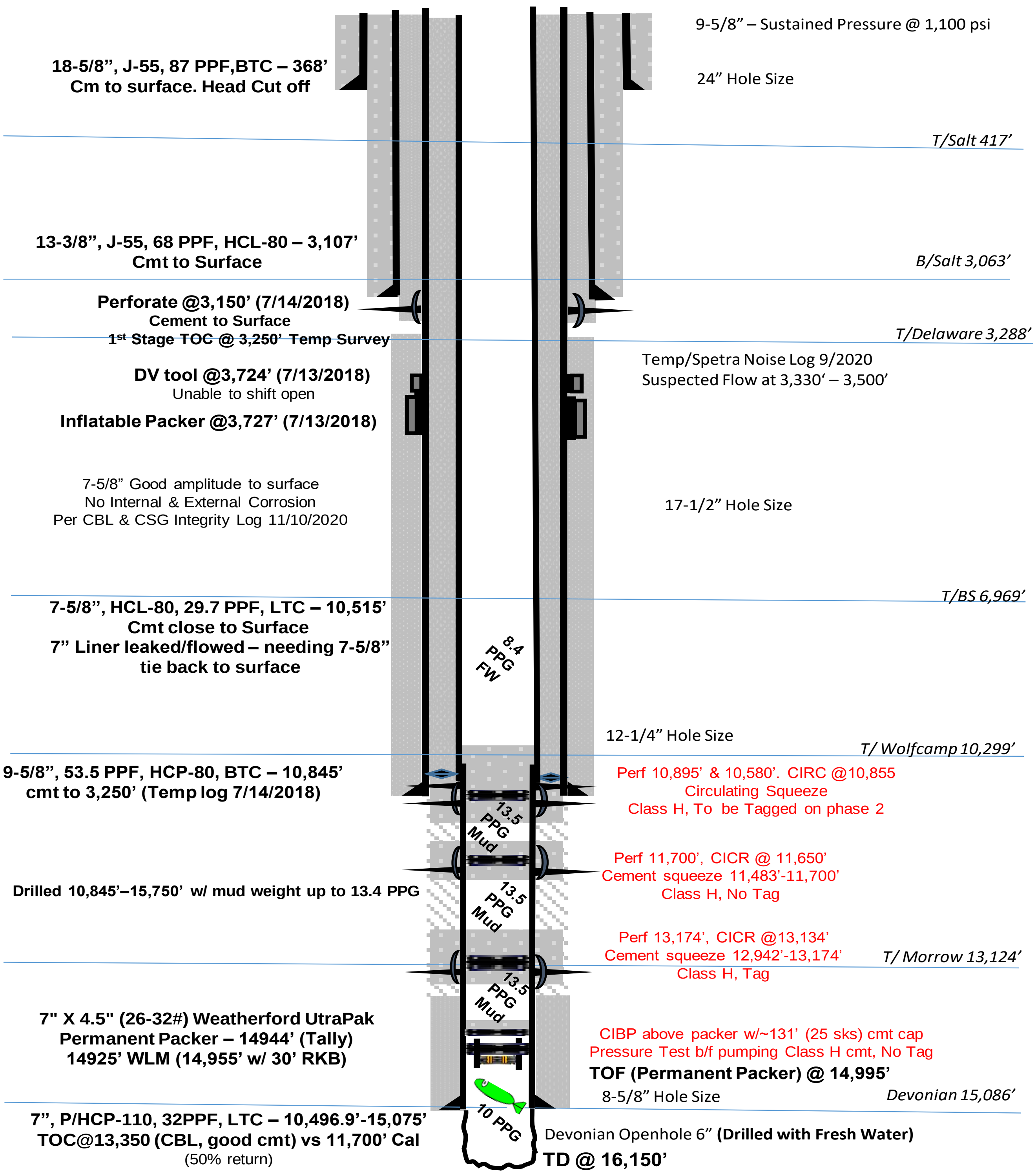
67) ND BOP and RD P&A rig

66) Cut and cap to complete the P&A operations
NOTE: Cut off wellhead 5' below surface casing flange. Install P&A marker with cement to comply with regulations
NOTE: Clean up location and move out. Photograph P&A marker and record GPS location.
NOTE: Top-up all annulus with cement if found below surface

Remuda Basin 001 SWD
API# 300-154-4388
T25S-R29E-S25
Eddy County, New Mexico

KB/GL:	30'
Spud:	6/23/2018

Proposed -Phase 1-

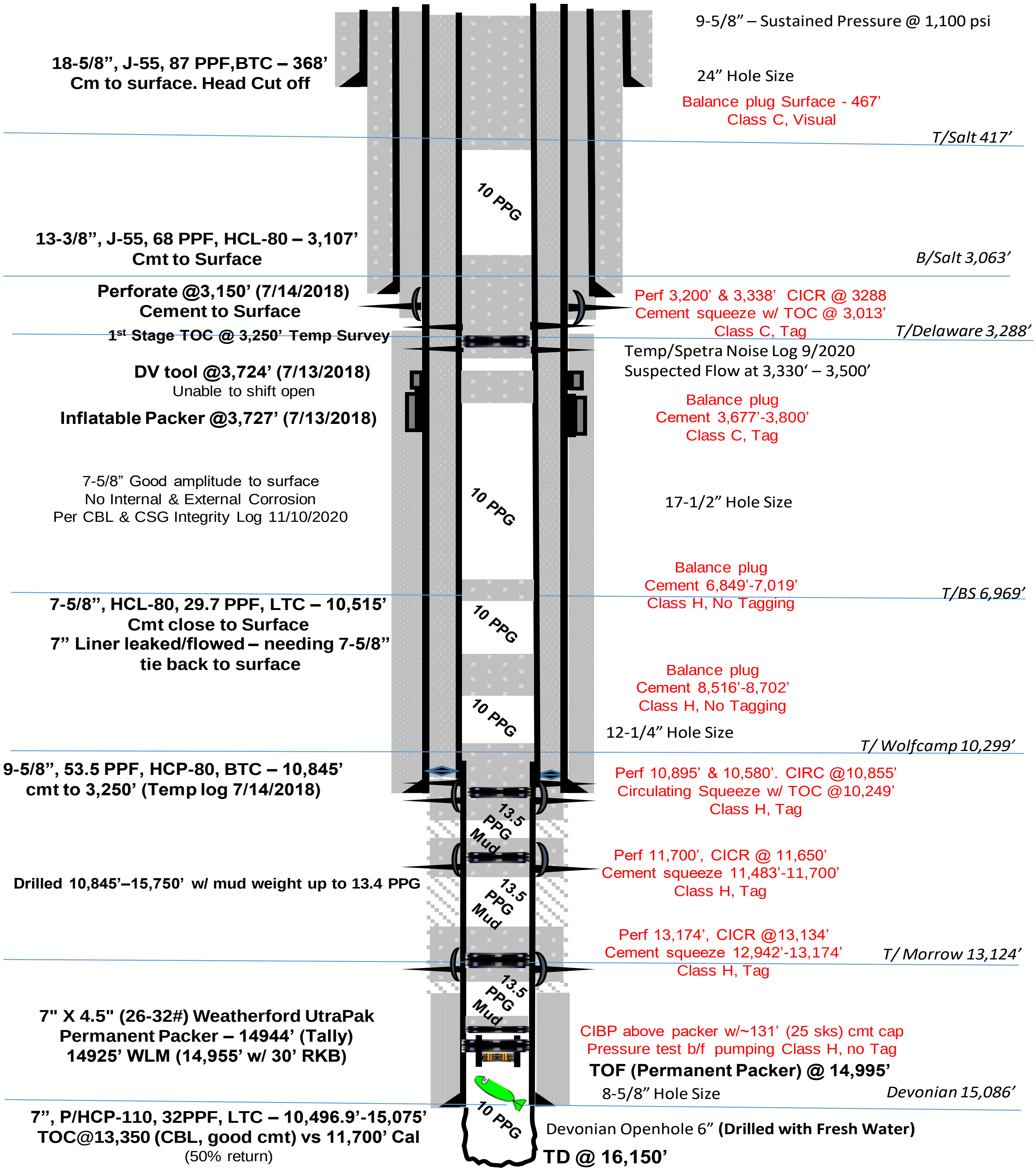


Remuda Basin 001 SWD

API# 300-154-4388
T25S-R29E-S25
Eddy County, New Mexico

KB/GL:	30'
Spud:	6/23/2018

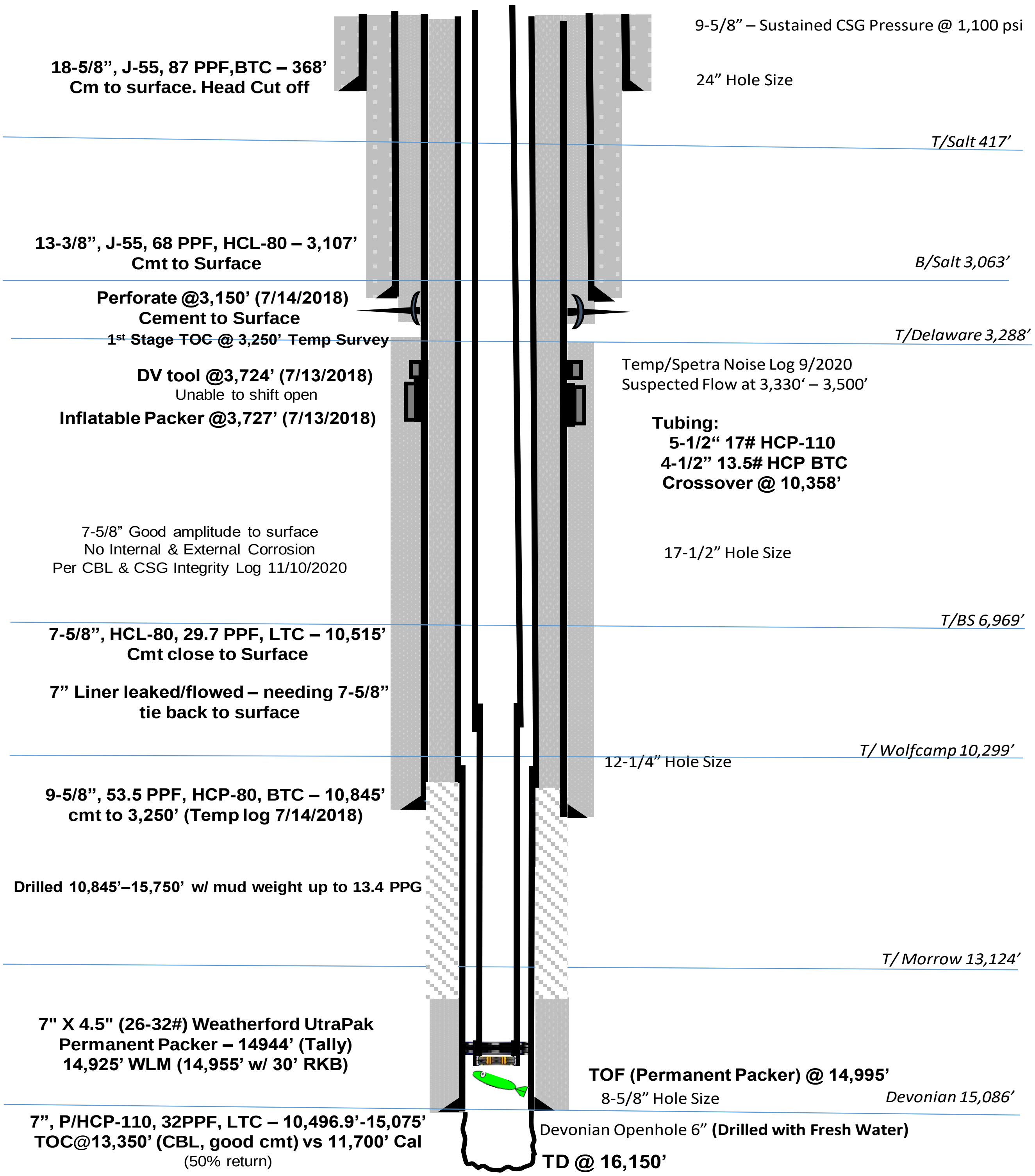
Proposed
- Phase 2 -



Remuda Basin 001 SWD
API# 300-154-4388
T25S-R29E-S25
Eddy County, New Mexico

KB/GL:	30’
Spud:	6/23/2018

Current



Remuda Basin 001 SWD

Background / Analysis

Remuda Basin SWD 001 (API 3001544344) was drilled in September 2018. The well was originally planned with 7" liner and 9-5/8" production casing. However, due to issues encountered on the 2nd cementing stage on the 9-5/8" casing, incomplete cement coverage on the 7" casing, and leaky liner packer; a 7-5/8" liner tie-back was ran. Listed below are futher details for each of the issues:

- The DV tool at 3,724' was found to be inoperable during the cementing operation on the 9-5/8" casing. In order to pump the 2nd stage of the cement operation, perforation was carried out at 3,150' (574' above the DV tool and 100' above the cement top @3250' via Temperature survey) on 9-5/8" casing. Cement was circulated to surface without issue.
- The 7" liner had incomplete cement coverage. Only 50% returns was achieved during the primary cement job on the 7" liner. The top of cement was then estimated (calculated) at 11,900', covering ~3,200' of 4,578' section. However, this estimation was too optimistic. Subsequently, a CBL was acquired 2 years later in October 2020 which shows the TOC at ~13,250'. It now believed that gas above the TOC to bubble up behind the 7" casing annular . Though less coverage, the cement quality was excellent and should have provided adequate barrier between injection zone and the formations above.
- The liner packer was found leaky while drilling the Devonian open-hole section. Extensive rig time was spent to circulated out gas. Rather than squeezing the liner top, decision was made to run the 7-5/8" liner tieback and cement to surface with 13.3 PPG cement. The cement hydrostatic and rheology were probably inadequate stopping gas migration while being cured. Subsequent geochemistry finger-print analysis was done on gas samples collected from 7-5/8" x 9-5/8" annulus. It was concluded that the gas has higher maturity and deeper the Wolfcamp (or any gas produced from offset wells). The gas is interpreted as sourcing much deeper than the 9-5/8 casing point and likely to have migrated up while cement behind the liner tie-back was being cured, creating a micro annulus channel.

The Remuda Basin SWD openhole section on the Devonian Formation was then drilled to TD without much issue. The injection zone required much lower mud weight compared to the section cased with 7" liner (8.5 vs 13.1 PPG). The well was completed with 5-1/2" x 4-1/2" tapered tubing design. The open-hole section in the Devonian formation was stimulated on 27 May 2019 with 20,000 Gallons of 20% gelled HCL. A successful MIT (pump and hold pressure) was initially carried out on May 29, 2019 witness by a State Inspector. However, the well failed the 2nd MIT test on July 23, 2019 upon learning that the 7-5/8" x 9-5/8" annulus had high pressure and failed to bleed off. The NMOCD allowed XTO to commence injection with conditions. One of the condition was to cease injection when any of the annulus pressure exceed 1000 psi.

Injection started injection on September 25, 2019. And despite the best effort, it was not possible to keep the annulus pressure below 1000 pis. Not only the well had the high intermediate casing pressure, it also had high production casing pressure (inside 7-5/8" casing). A diagnostic noise log was run in September 2020 and a subsequent WO was carried out in October 2020 (new tubing and packer). Yet, neither the production casing nor the intermediate casing pressure could be alleviated. Injection temporarily restarted at insignificantly lower rate and stopped completely by April 21, 2021. The well injection permit had expired. Communication record shows XTO had approached the NMOCD in March 2020 to plug and drill a replacement well two years. However, the process halted during the market downturn and the project never restarted.

Recommendation

Due to extended inactivity period, Remuda Basin SWD 001 is no longer in compliance with the State regulations. It is recommended that the well will be plugged for compliance. There is a small chance (<10%) the issue can be fixed while performing the P&A cement plugs on the 7" liner. If successful, the ~$15M total investment on the well and SWD facility can be savaged relatively easily. Therefore, the plugging operation is recommended to be done in two phases. Phase 1 will involve plugging the well up to the 7" liner top. A short pause of P&A operation (~3 months) is recommended to assess 1) effectiveness of cement plugs and 2) whether to re-permit and re-enter the well (with addtional approval). If both the 7-5/8" production casing and the 7-5/8" x 9-5/8 annulus pressure failed to alleviate, phase 2 of the P&A operation will promptly be conducted.

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State of New Mexico
Energy, Minerals and Natural Resources
Oil Conservation Division
1220 S. St Francis Dr.
Santa Fe, NM 87505

CONDITIONS

Action 335413

CONDITIONS

Operator:	
XTO ENERGY, INC 6401 Holiday Hill Road Midland, TX 79707	OGRID: 5380
	Action Number: 335413
	Action Type: [C-103] NOI Plug & Abandon (C-103F)

CONDITIONS

Created By	Condition	Condition Date
mgebremichael	Please ensure to perform a bubble test for each cement squeeze performed.	5/21/2024