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

Carlsbad Field Office
OCD Hobbs

HOBBS OCD

OCT 2 4 2016

RECEIVED

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.
NM[illegible]

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

8. Well Name and No.
ZIA AGI 2

2. Name of Operator
DCP MIDSTREAM LP

Contact: ALBERTO A GUTIERREZ
E-Mail: aag@geolex.com

9. API Well No.
30-025-42207-00-X1

3a. Address
370 17TH STREET SUITE 2500
DENVER, CO 80208 5406

3b. Phone No. (include area code)
Ph: 505-842-8000

10. Field and Pool, or Exploratory
AGI

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*

Sec 19 T19S R32E Lot 3 1900FSL 950FWL ✓
32.644036 N Lat, 103.811145 W Lon

11. County or Parish, and State

LEA 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.)

DCP Midstream LP requests minor changes to the final well schematic. Attached is the new well schematic with an updated casing design consisting of casing that is of equal or greater grade. The top 300' of production casing will consist of 7-5/8" casing to accommodate OD of SSSV, and the remaining production casing (300' to 13,755') will be what was originally approved (7").

SUBJECT TO LIKE APPROVAL BY STATE

DCP Midstream LP requests a change to the 2nd intermediate casing seating depth. The new 2nd intermediate casing depth is set at 4700' in competent rock. This is to ensure a proper seal of the Capitan Reef. Furthermore, by setting the casing at this depth DCP has safer options for Zia AGI #2 in case pressure from Zia AGI #1 is encountered.

DCP Midstream LP requests the approval of the use of Halliburton "WellLock" resin-based cement in the intervals of the well potentially impacted from acid gases. Depths and volumes are detailed in

SEE ATTACHED FOR CONDITIONS OF APPROVAL

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

Electronic Submission #354727 verified by the BLM Well Information System
For DCP MIDSTREAM LP, sent to the Hobbs
Committed to AFMSS for processing by PRISCILLA PEREZ on 10/14/2016 (17PP0043SE)

Name *(Printed/Typed)* ALBERTO A GUTIERREZ | Title CONSULTANT TO DCP MIDSTREM, LP

Signature (Electronic Submission) | Date 10/13/2016

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By **Teungku Muchlis Krueng** | Title PETROLEUM ENGINEER | Date

APPROVED
OCT 14 2016
BUREAU OF LAND MANAGEMENT
CARLSBAD FIELD OFFICE

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 within its jurisdiction.

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

KZ

Additional data for EC transaction #354727 that would not fit on the form

32. Additional remarks, continued

the attached cementing program. This cement is corrosion resistant cement of better quality than the approved ThermaLock or equivalent.

DCP Midstream LP requests permission to employ a 5M BOP/BOPE for completion of the final open hole segment of the well from depths of approximately 13,755' to 14,750'. The approved 10M system will still be employed from drilling, casing, cementing and testing of the 7" production casing (to approximately 13,755'). This change simplifies operations, and this disposal zone is generally under-pressured in this area.

DCP Midstream LP requests a change in production tubing to using approximately 13,400' of 3-1/2" 9.3 ppf L80 VAM top steel tubing, and approximately 300' (13,400' to 13,700') of 3-1/2" 9.3 ppf 28CR110 corrosion-resistant steel for overall corrosion resistant design. See attached for the well completion diagram including tubing and packer assembly.

Lea County, NM
Section 19 T19S R32E

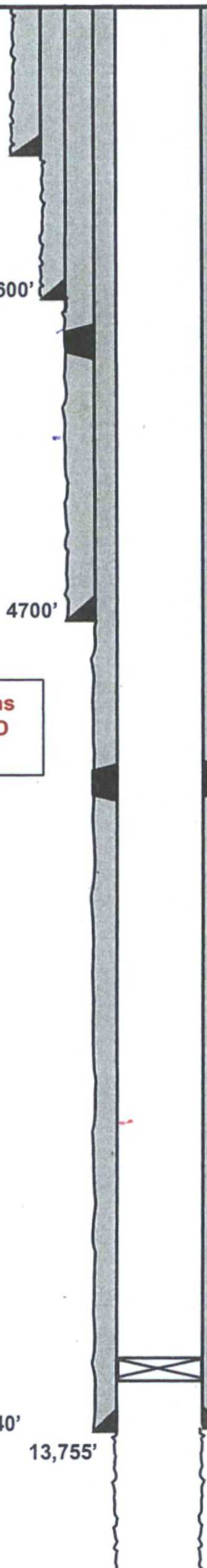
SHL
1900' FSL
950' FWL

KB: 3572' GL: 3547'

Zia AGI #2D
API: 30-025-42207
Lat/Long: 32°38'38.29"N / 103°46'40.02"W

Well Type: Devonian AGI
DCP Midstream, LP

Rig:	Scan Freedom
Cmt:	Halliburton
Mud:	Nova
Dir Drlg:	Integrity
Wellhead:	GE Oil & Gas
Casing:	CRA / JD Rush
Float Equip:	DL / HES
AFE Cost:	$Update
AFE Days:	47



Formation tops
- Rustler @ 740'
- Top of Salt @ 889'
- Base of Salt @ 2353'
- Yates @ 2426'
- 7 Rivers @ 2652'
- Reef @ 2760'
- Base of Reef @ 4436'
- Delaware @ 4718'
- Bone Spring @ 7046'
- Wolfcamp @ 10,270'
- Strawn @ 11,120'
- Atoka @ 11,549'
- Morrow @ 12,075'
- Mississippian @ 12,665'
- Miss Lime @ 13,065'
- Woodford @ 13,615'
- Devonian/Silurian @ 13,740'
- Fusselman @ 14,031'
- Montoya @ 14,511'

Offset Acid Gas Injections
F/ 5400' TVD – 6100' TVD
DVT @ ~ 6,350'

20" 106.5# J-55 BTC @ 800'

Lead: 1175 sx
Class C + 4%Gel
13.5 ppg 1.75 ft³/sx

Tail: 250 sx
Class C + 1% $CaCl_2$
14.8 ppg 1.34 ft³/sx

Bit Size: 26"
Surface Mud:
FW Spud Mud
8.4 ppg
FV 28-29
WL NC

13-3/8" 61# J-55 BTC @ 2,600'

Lead: 1700 sx
Class C + 4%Gel
13.5 ppg 1.75 ft³/sx
100% excess

Tail: 250 sx
Class C + 1% $CaCl_2$
14.8 ppg 1.34 ft³/sx

Bit Size: 17-1/2"
Intrmd Mud:
Brine
10 ppg,
FV @ 28-29
WL NC

9-5/8" 40# L80 BTC @ 4,700'
DVT/ECP 100' above Reef.
DVT/ECP min 50' below 13-3/8" shoe.

BHST @ 4700' is 115° F
1st stg: Lead: 525 sx
35:65:6 C Blend
12.7 ppg 2 ft³/sx
TT: 4:30+
Tail: 250 sx
Class C
14.8 ppg 1.34 ft³/sx
TT: 3:00

BHST @ 2650' is 95° F
2nd stg: Lead: 650 sx
Class C + 4% Gel
13.5 ppg 1.75 ft³/sx
TT: 4:30
Tail: 100 sx
Class C + 1% CaCl2
14.8 ppg 1.34 ft³/sx
TT: 3:00

Bit Size: 12-1/4"
Intrmd 2 Mud:
FW
8.4 ppg
FV 28-29
WL NC

7-5/8" 33.7# HCP110 LTC 0 – 300'
7-5/8" 33.7# LTC Box X 7" 29# LTC Pin (XO)
7" 29# HCP110 LTC f/ 300' – 5000'
7" 29# LTC Box X 7" 32# VAM TOP Pin (XO)
7" 32# SM2035-110 VAM TOP f/ 5000' – 6350'
DVT (7" 32# VAM TOP box X 7" 29# LTC pin)
7" 29# HCP110 LTC f/ 6350' – 13,455'
7" 29# LTC Box X 7" 32# VAM TOP Pin (XO)
7" 32# SM2035-110 VAM TOP f/ 13,455' – 13,755' (FE to match)

Bit Size: 8-3/4"
Prod Mud:
WBM
9.0 – 11 ppg
See
Mud Program

BHST @ 13,755' is 200° F
1st Stage
Lead: 650 sx
50:50:10 H Blend
11.9 ppg 2.5 ft³/sx
TT: 5:30+
40% Excess + 100 sx

Total: ~~[illegible]~~ 750 sx

Tail: 40 BBLs
WellLock Resin
12.5 ppg
TT: 4:00+

225 ft³

BHST @ 6350' is 130° F
2nd stage
Lead: 350 sx
50:50:10 C Blend
11.9 ppg 2.51 ft³/sx
TT: 3:00+

Tail: 80 BBLs
WellLock Resin
12.5 ppg
TT: 3:00+

449 ft³

$$40\ \text{bbls} \times \frac{42\ \text{gal}}{1\ \text{bbls}} \times \frac{1\ \text{ft}^3}{7.481\ \text{gal}} = X\ \text{ft}^3$$

7" casing pt to be picked by mud loggers. 15' into the Devonian.

Will set comp bridge plug inside the 7" before installing disposal head

Formation Evaluation
- Gyro @ TD
- Mud log out from 9-5/8" intermediate
- Open Hole logs – see log prog

Bit Size: 6"
OH Mud:
Fresh
8.4 – 9.2 ppg

Smith: 10/12/16

CEMENT PROGRAM

The cement program is summarized in Table 1 below. All cement for each casing string will be circulated to the surface, using the calculated excesses shown in Table 2 below. After cement curing, each casing string will be pressure tested before drilling out the diverters and shoes, and a formation pressure test will be conducted and approved prior to deeper drilling. All cement jobs for all casing strings will be verified using 360° cement bond logging and analyses.

Table 1: Cement Program and Design Specifications

Casing	Interval (ft.)	# Sks	Wt. lb/ gal	Yld ft3/ sack	H_20 gal/sk	500# Comp. Strength (hours)	Slurry Description
20"	0 - 800	1175	13.5	1.75	9	12	Lead: Class C + 4% Gel
		250	14.8	1.34	6.34	8	Tail: Class C + 1% CaCl2
13-3/8"	0 – 2,600	1700	13.5	1.75	9	12	Lead: Class C + 4% Gel
		250	14.8	1.34	6.34	8	Tail: Class C + 1% CaCl2
9-5/8" 1st stg	2,650 – 4,700	450	12.7	2	10.6	16	Lead: Econocem HLC 35:65:6 C Blend
		250	14.8	1.34	6.34	8	Tail: Class C + 1% CaCl2
9-5/8" 2nd stg	0 – 2,650	650	13.5	1.75	9	12	Lead: Class C + 4% Gel
		100	14.8	1.34	6.34	8	Tail: Class C + 1% CaCl2
7" 1st stg	6,350 – 13,755	650	11.9	2.5	19.1	24	Lead: 50:50:10 H Blend
		40 (bbls)	12.5	40 (bbls	N/A	24	Tail: WellLock Resin
7" 2nd stg	0 – 6,350	350	11.9	2.51	19.1	24	Lead: 50:50:10 C Blend
		80 (bbls)	12.5	80 (bbls)	N/A	24	Tail: WellLock Resin

N/A = Not Applicable

The DVT/ECP for the 9-5/8" 2nd intermediate casing will be set @ 2650'. This setting depth for the DVT/ECP will ensure we get a proper seal above the initial losses of the reef to ensure a good cement job for the 9-5/8" casing. To get a proper cement job if the BLM is going to enforce us to be 50' below the 13-5/8" casing shoe, then we need the 13-3/8" casing shoe to be set no deeper than 2600'. Setting the 13-3/8" casing at 2600' will case the salt and the top of the Yates.

The DVT for the 7" casing will be set @ 6,350'. Volumes subject to change from hole observations and/or fluid calipers. Lab reports with the 500 psi comp strength time for the cement will be onsite for review. After drilling the OH disposal interval, and before installing disposal head, operator will install a comp bridge plug inside the 7" casing.

Table 2: Cement Excess for Casing Strings

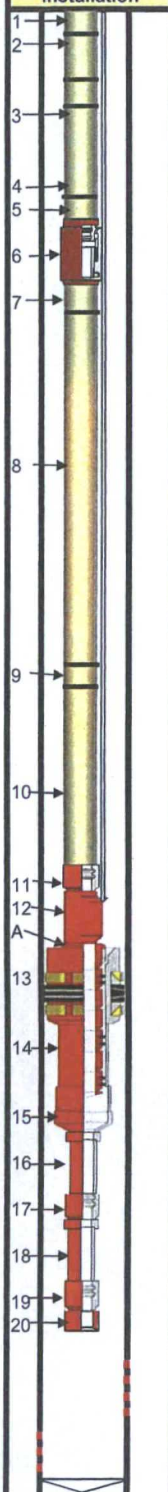
Casing String	TOC	% Excess
20"	0'	50%
13-3/8"	0'	100%
9-5/8"	0'	50%
7"	0'	40% + 100 sacks

HALLIBURTON

DCP Midstream

ZIA AGI #2	Company Rep.	Brian Collins	
Lea County New Mexico	Sales Rep.	Lynn Talley	
9/13/16	Office	432-682-4305	

Installation



Installation	Length	Depth	Description	OD	ID
			KB Correction		
			Tubing Hanger		
			Casing String) 7 5/8" 33.7# x 7" 29# & 32# Tapered Casing String		
			1) 1 joint 3 1/2" 9.3# BTS-8 L-80 Tubing Joint Inverted	3.500	2.920
			2) Double Pin Sub (DCP)	3.500	2.920
			3) Tubing Subs (As Required) (DCP)	3.500	2.920
			4) 3 1/2" 9.3# BTS-8 L-80 Tubing	3.500	2.920
			5) 3 1/2" 9.3# BTS-8 Box X 3 1/2" 9.2# AB TC-II Pin L-80 Sub (DCP)	3.500	2.959
			6) Halliburton Tubing Retrievable Safety Valve-NE 3 1/2" 9.2# AB TC-II Box X Pin 102588547 SN ###### Nickel Alloy 925 10K Rated 875 Minimum PSI Closing, 2000 PSI Open, 2.813" R Profile	5.300	2.813
			7) 3 1/2" 9.2# AB TC-II Box X 3 1/2" 9.3# BTS-8 Pin L-80 Sub (DCP)	3.907	2.920
			8) 3 1/2" 9.3# BTS-8 L-80 VAMTOP steel tubing to 13,400'	3.500	2.920
			9) 3 1/2" 9.3# BTS-8 Box X 3 1/2" 9.2# VAMTOP Pin L-80 Sub (DCP)	3.915	2.920
			10) 3 1/2" 9.3# 28CR110 corrosion-resistant steel (13,400' - 13,700')	3.500	
	1.33		11) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) Nickel Alloy 925	3.937	2.562
	4.86		12) Schlumberger P-T Receptacle Alloy PN 101643587 RLV-A2 SN ######## 3 1/2" 9.2# SGM ASSY SQ1 Pin x Pin Drift OD-5.227 Drift ID-2.867	4.910	2.992
			A) Halliburton Seal Assembly		
	1.76		A1) Straight Slot Locator Sub 3 1/2" 9.2# VAMTOP Box X 3 1/2" 10.2# VAMINSIDE Pin Incoloy 925 (102351212)(SN-######)	4.470	2.883
	8.00		A2) 2-Seal Unit Ext. 3 1/2" 10.2# VAMINSIDE Nickel Alloy 925 (158726) (SN-#######)	3.860	2.902
	1.99		A3) 2-Seal Units 4" X 3 1/2" 10.2 VAMINSIDE Nickel Alloy 925 Molded AFLAS/Flourel Seals 4.07 OD, 8000 PSI	4.050	2.883
	3.00		A4) 3-Seal Units 4" X 3 1/2" 10.2 VAMINSIDE Nickel Alloy 925 Molded AFLAS/Flourel Seals 4.07 OD, 8000 PSI (102133617)(SN-########)	4.050	2.883
	0.55		A5) Mule Shoe Guide 3 1/2" 10.2# VAMINSIDE Nickel Alloy 925 (102133560)(SN-########)	3.960	2.972
			Land Seals w/~26,000# Compression @ Surface, ~20K @ Packer		
			Pick Up Weight ###### Slack Off #######		
			Halliburton Packer Assembly		
	3.11	13,700.00	13) Halliburton 7" 26-32# BWD Permanent Packer 4.00" Bore Incoloy 925 (101303583) (SN #######)	5.875	4.000
	12.00	13,703.11	14) Seal Bore Extension 4.00" X 12' Incoloy 925 (120051359) (SN-#######)	5.020	4.000
	0.83	13,715.11	15) Seal Bore Ext. Crossover 4 75" 8UN Box X 3 1/2" 9.2# VAMTOP Pin Incoloy 925 (101719647)(SN-######)	5.650	2.992
	6.33	13,715.94	16) 6' x 3 1/2" 9.2# VAMTOP Box x Pin Pup Joint Incoloy 925	3.540	2.992
	1.33	13,722.27	17) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) (SN-#######) Nickel Alloy 925	3.937	2.562
	6.34	13,723.60	18) 6' x 3 1/2" 9.3# VAMTOP Box x Pin Pup Joint Incoloy 925	3.540	2.992
	1.33	13,729.94	19) Halliburton 2.562" R Nipple 3 1/2" 9.2# VAMTOP Box x Pin (102204262) (SN-#######) Nickel Alloy 925	3.937	2.562
	0.66	13,731.27	20) Wireline Re-entry Guide 3 1/2" 9.2# VAM Incoloy 925	3.960	2.992
		13,731.93	Bottom Of Assembly		
			DIESEL USED FOR PACKER FLUID		

Conditions of Approval

OPERATOR'S NAME:	DCP Midstream LP
LEASE NO.:	NM0149956
WELL NAME & NO.:	2-Zia AGI
SURFACE HOLE FOOTAGE:	1900'/S & 950'/W
BOTTOM HOLE FOOTAGE	1655'/S & 1655'/W
LOCATION:	Sec. 19, T. 19 S., R. 32 E.
COUNTY:	Lea County, New Mexico

A. DRILLING OPERATIONS REQUIREMENTS

The BLM is to be notified in advance for a representative to witness:

a. Spudding well (minimum of 24 hours)
b. Setting and/or Cementing of all casing strings (minimum of 4 hours)
c. BOPE tests (minimum of 4 hours)

☒ **Lea County**
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575) 393-3612

1. A Hydrogen Sulfide (H2S) Drilling Plan shall be activated **500** feet prior to drilling into the **Delaware** formation. **As a result, the Hydrogen Sulfide area must meet Onshore Order 6 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.**

2. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval. **If the drilling rig is removed without approval – an Incident of Non-Compliance will be written and will be a "Major" violation.**

3. Floor controls are required for 3M or Greater systems. These controls will be on the rig floor, unobstructed, readily accessible to the driller and will be operational at all times during drilling and/or completion activities. Rig floor is defined as the area immediately around the rotary table; the area immediately above the substructure on which the draw works is located, this does not include the dog house or stairway area.

4. **The record of the drilling rate along with the GR/N well log run from TD to surface (horizontal well – vertical portion of hole) shall be submitted to the BLM office as well as all other logs run on the borehole 30 days from completion. If available, a digital copy of the logs is to be submitted in addition to the paper copies. The Rustler top and top and bottom of Salt are to be recorded on the Completion Report.**

B. CASING

Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size or are Non-API. The Operator can exchange the components of the proposal with that of superior strength (i.e. changing from J-55 to N-80, or from 36# to 40#). Changes to the approved cement program need prior approval if the altered cement plan has less volume or strength or if the changes are substantial (i.e. Multistage tool, ECP, etc.).

The initial wellhead installed on the well will remain on the well with spools used as needed.

Centralizers required on surface casing per Onshore Order 2.III.B.1.f.

Wait on cement (WOC) for Water Basin:
After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements. DURING THIS WOC TIME, NO DRILL PIPE, ETC. SHALL BE RUN IN THE HOLE.

Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string. Have well specific cement details onsite prior to pumping the cement for each casing string.

No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.

Risks:
Possibility of Water Flows in the Capitan Reef, in the Salado and in the Artesia Group.
Possibility of Lost Circulation in the Rustler, Capitan Reef, Red Beds, Delaware and in the Artesia Group.

1. The **20** inch surface casing shall be set at approximately **800** feet **(in a competent bed below the Magenta Dolomite, which is a Member of the Rustler, and if salt is encountered, set casing at least 25 feet above the salt)** and cemented to the surface.
    a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.
    b. **Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry.**
    c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.
    d. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The minimum required fill of cement behind the **13 3/8** inch intermediate casing is:

☒ Cement to surface. If cement does not circulate see B.1.a, c-d above.

3. The minimum required fill of cement behind the **9 5/8** inch production casing is:
Operator has proposed DV tool at depth of 2650'. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range.

a. First stage to DV tool:
☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage.

b. Second stage above DV tool:
☒ Cement to surface. If cement does not circulate see B.1.a, c-d above.

Formation below the 9-5/8" shoe to be tested according to Onshore Order 2.III.B.1.i. Test to be done as a mud equivalency test using the mud weight necessary for the pore pressure of the formation below the shoe (not the mud weight required to prevent dissolving the salt formation) and the mud weight for the bottom of the hole. Report results to BLM office.

4. The minimum required fill of cement behind the **7-5/8** and **7** inch intermediate casing is:

Operator has proposed DV tool at depth of 6350'. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range.

c. First stage to DV tool:
☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage.

d. Second stage above DV tool:
☒ Cement to surface. Operator to provide method of verification.

Formation below the 7-5/8" shoe to be tested according to Onshore Order 2.III.B.1.i. Test to be done as a mud equivalency test using the mud weight necessary for the pore pressure of the formation below the shoe (not the mud weight required to prevent dissolving the salt formation) and the mud weight for the bottom of the hole. Report results to BLM office.

5. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

C. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API 53.

2. Variance approved to use flex line from BOP to choke manifold. Check condition of flexible line from BOP to choke manifold, replace if exterior is damaged or if line fails test. Line to be as straight as possible with no hard bends and is to be anchored according to Manufacturer's requirements. The flexible hose can be exchanged with a hose of equal size and equal or greater pressure rating. **Anchor requirements, specification sheet and hydrostatic pressure test certification matching the hose in service, to be onsite for review. These documents shall be posted in the company man's trailer and on the rig floor.** If the BLM inspector questions the straightness of the hose, a BLM engineer will be contacted and will review in the field or via picture supplied by inspector to determine if changes are required (operator shall expect delays if this occurs).

3. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **surface casing shoe** shall be **2000 (2M)** psi.

4. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **9 5/8 inch intermediate casing** shoe shall be **10,000 (10M)** psi. **10M system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.**

5. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **7 5/8 inch intermediate casing** shoe shall be **5000 (5M)** psi. **5M system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.**

6. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.
   a. In a water basin, for all casing strings utilizing slips, these are to be set as soon as the crew and rig are ready and any fallback cement remediation has been done. The casing cut-off and BOP installation can be initiated four hours after installing the slips, which will be approximately six hours after bumping the plug. For those casing strings not using slips, the minimum wait time before cut-off is eight hours after bumping the plug. BOP/BOPE testing can begin after cut-off or once cement reaches 500 psi compressive strength (including lead when specified), whichever is greater. However, if the float does not hold, cut-off cannot be initiated until cement reaches 500 psi compressive strength (including lead when specified).

b. The tests shall be done by an independent service company utilizing a test plug **not a cup or J-packer**.

c. The test shall be run on a 5000 psi chart for a 2-3M BOP/BOP, on a 10000 psi chart for a 5M BOP/BOPE and on a 15000 psi chart for a 10M BOP/BOPE. If a linear chart is used, it shall be a one hour chart. A circular chart shall have a maximum 2 hour clock. If a twelve hour or twenty-four hour chart is used, tester shall make a notation that it is run with a two hour clock.

d. The results of the test shall be reported to the appropriate BLM office.

e. All tests are required to be recorded on a calibrated test chart. **A copy of the BOP/BOPE test chart and a copy of independent service company test will be submitted to the appropriate BLM office.**

f. The BOP/BOPE test shall include a low pressure test from 250 to 300 psi. The test will be held for a minimum of 10 minutes if test is done with a test plug and 30 minutes without a test plug. This test shall be performed prior to the test at full stack pressure.

g. BOP/BOPE must be tested by an independent service company within 500 feet of the top of the **Wolfcamp** formation if the time between the setting of the intermediate casing and reaching this depth exceeds 20 days. This test does not exclude the test prior to drilling out the casing shoe as per Onshore Order No. 2.

D. DRILLING MUD

Mud system monitoring equipment, with derrick floor indicators and visual and audio alarms, shall be operating before drilling into the **Wolfcamp** formation, and shall be used until production casing is run and cemented.

E. WELL COMPLETION

A NOI sundry with the procedure to complete this well in compliance with BLM and NMOCD requirements shall be submitted and approved prior to commencing completion work.

The procedure will be reviewed to verify that the completion will allow the operator to restrict the injection fluid to the approved formation. NOTE: The sundry shall include data from the conventional core analysis and logs with detailed analysis of the reservoir seal depth related to the perforation interval and the packer setting depth. It may also need to include previously submitted information.

DO NOT install injection tubing until approval is received

NOTE: (include with NOI sundry) prior to beginning Acid Gas Injection at the well, the Operator shall provide all Operators of existing wells within a 1 mile radius with a notice of beginning injection operations and include a map of the possible worst case scenario H2S exposure area(s). BLM is to be copied on this notice mailing. (H2S Public Protection Plan)

An MIT test must be conducted annually and submitted to the BLM via subsequent sundry.

F. DRILL STEM TEST

If drill stem tests are performed, Onshore Order 2.III.D shall be followed.

G. WASTE MATERIAL AND FLUIDS

All waste (i.e. drilling fluids, trash, salts, chemicals, sewage, gray water, etc.) created as a result of drilling operations and completion operations shall be safely contained and disposed of properly at a waste disposal facility. No waste material or fluid shall be disposed of on the well location or surrounding area.

Porto-johns and trash containers will be on-location during fracturing operations or any other crew-intensive operations.

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