Sante Fe Main Office
Phone: (505) 476-3441

General Information
Phone: (505) 629-6116

Online Phone Directory
https://www.emnrd.nm.gov/ocd/contact-us

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

Form C-101
August 1, 2011

Permit 394971

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

1. Operator Name and Address Earthstone Operating, LLC 300 N. Marienfeld St Ste 1000 Midland, TX 79701		2. OGRID Number 331165 3. API Number 30-025-55200
4. Property Code 332607	5. Property Name OUTLAND STATE UNIT	6. Well No. 136H

7. Surface Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
C	1	21S	34E	3	401	N	2330	W	Lea

8. Proposed Bottom Hole Location

UL - Lot	Section	Township	Range	Lot Idn	Feet From	N/S Line	Feet From	E/W Line	County
M	1	21S	34E	M	100	S	330	W	Lea

9. Pool Information

GRAMA RIDGE;BONE SPRING, NORTH	28434

Additional Well Information

11. Work Type New Well	12. Well Type OIL	13. Cable/Rotary	14. Lease Type State	15. Ground Level Elevation 3684
16. Multiple N	17. Proposed Depth 18896	18. Formation 3rd Bone Spring Sand	19. Contractor	20. Spud Date 9/24/2025
Depth to Ground water		Distance from nearest fresh water well		Distance to nearest surface water

☒ **We will be using a closed-loop system in lieu of lined pits**

21. Proposed Casing and Cement Program

Type	Hole Size	Casing Size	Casing Weight/ft	Setting Depth	Sacks of Cement	Estimated TOC
Surf	17.5	13.375	54.5	1948	1470	0
Int1	12.25	9.625	40	5731	1500	0
Prod	8.75	5.5	20	18896	2160	5231

Casing/Cement Program: Additional Comments

DV tool set @ 3764 w/2 Stage Cement job on Intermediate Casing. Production hole is a tapered hole: 8.75" to 11730' and 8.5" hole from 11730'-18896' Detailed Drilling Plan attached. Intermediate Hole will be drilled with Water Based Mud

22. Proposed Blowout Prevention Program

Type	Working Pressure	Test Pressure	Manufacturer
Annular	2500	2500	
Double Ram	5000	5000	
Pipe	5000	5000	
Blind	5000	5000	

23. I hereby certify that the information given above is true and complete to the best of my knowledge and belief. I hereby certify that no additives containing PFAS chemicals will be added to the completion or recompletion of this well. **I further certify I have complied with 19.15.14.9 (A) NMAC ☒ and/or 19.15.14.9 (B) NMAC ☒, if applicable.** Signature:		**OIL CONSERVATION DIVISION**	
Printed Name: Electronically filed by Stephanie Rabadue		Approved By: Jeffrey Harrison	
Title: Regulatory Manager		Title: Petroleum Specialist III	
Email Address: stephanie.rabadue@permianres.com		Approved Date: 9/15/2025	Expiration Date: 9/15/2027
Date: 8/8/2025	Phone: 432-260-4388	Conditions of Approval Attached	

C-102 Submit Electronically Via OCD Permitting	State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION	Revised July 9, 2024	
		Submittal Type:	☑ Initial Submittal ☐ Amended Report ☐ As Drilled

WELL LOCATION INFORMATION

API Number 30-025-55200	Pool Code 28434	Pool Name Grama Ridge; Bone Spring, North	
Property Code 332607	Property Name OUTLAND STATE UNIT		Well Number 136H
OGRID No. 372165	Operator Name PERMIAN RESOURCES OPERATING, LLC		Ground Level Elevation 3,684'
Surface Owner: ☒ State ☐ Fee ☐ Tribal ☐ Federal		Mineral Owner: ☒ State ☐ Fee ☐ Tribal ☐ Federal	

Surface Location

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
	1	21S	34E	LOT 3	401' FNL	2,330' FWL	32.521257°	-103.424518°	LEA

Bottom Hole Location

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
M	1	21S	34E		100' FSL	330' FWL	32.501074°	-103.431009°	LEA

Dedicated Acres	Infill or Defining Well	Defining Well API	Overlapping Spacing Unit (Y/N)	Consolidation Code
475.12	Infill	Pending	Y	C,F,O
Order Numbers. Pending			Well setbacks are under Common Ownership: ☒Yes ☐No	

Kick Off Point (KOP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
	1	21S	34E	LOT 3	401' FNL	2,330' FWL	32.521257°	-103.424518°	LEA

First Take Point (FTP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
	1	21S	34E	LOT 4	100' FNL	330' FWL	32.522082°	-103.431007°	LEA

Last Take Point (LTP)

UL	Section	Township	Range	Lot	Ft. from N/S	Ft. from E/W	Latitude	Longitude	County
M	1	21S	34E		100' FSL	330' FWL	32.501074°	-103.431009°	LEA

Unitized Area or Area of Uniform Interest	Spacing Unit Type ☒ Horizontal ☐ Vertical	Ground Floor Elevation:

OPERATOR CERTIFICATIONS	SURVEYOR CERTIFICATIONS
I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief, and, if the well is a vertical or directional well, that this organization either owns a working interest or unleased mineral interest in the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of a working interest or unleased mineral interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division. If this well is a horizontal well, I further certify that this organization has received the consent of at least one lessee or owner of a working interest or unleased mineral interest in each tract (in the target pool or formation) in which any part of the well's completed interval will be located or obtained a compulsory pooling order from the division.	I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief. MARK J. MURRAY NEW MEXICO 12177 REGISTERED PROFESSIONAL SURVEYOR Date: 8/4/2025
Signature Date 8/6/2025	Signature and Seal of Professional Surveyor
Jennifer Elrod Printed Name	Certificate Number: 12177 Date of Survey: 8/4/2025
jelrod@ntglobal.com Email Address	

Note: No allowable will be assigned to this completion until all interests have been consolidated or a non-standard unit has been approved by the division.

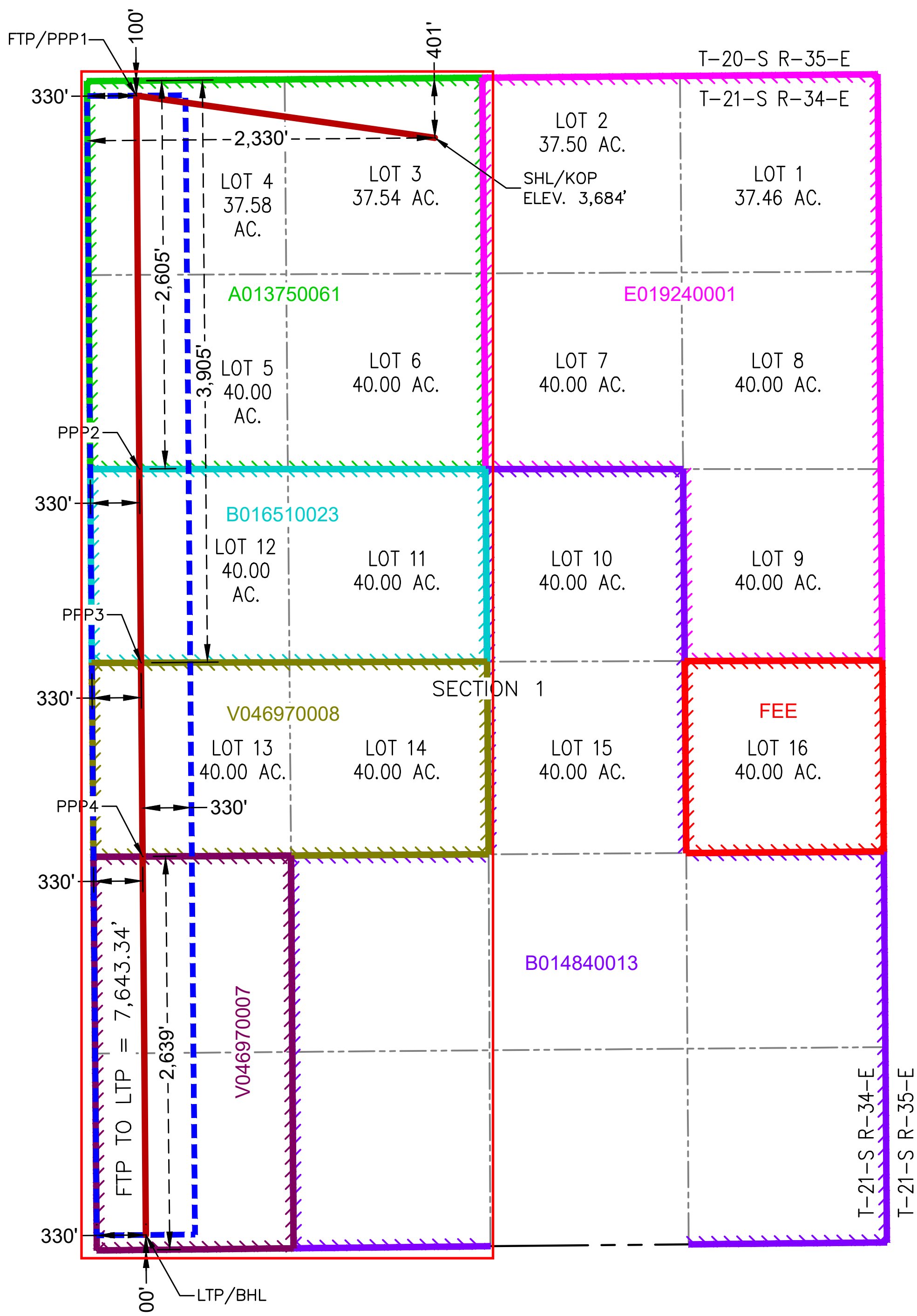
Received by OCD: 8/8/2025 6:41:16 AM

ACREAGE DEDICATION PLATS

This grid represents a standard section. You may superimpose a non-standard section, or larger area, over this grid. Operators must outline the dedicated acreage in a red box, clearly show the well surface location and bottom hole location, if it is directionally drilled, with the dimensions from the section lines in the cardinal directions. If this is a horizontal wellbore show on this plat the location of the First Take Point and Last Take Point, and the point within the Completed interval (other than the First Take Point or Last Take Point) that is closest to any outer boundary of the tract.

Surveyors shall use the latest United States government survey or dependent resurvey. Well locations will be in reference to the New Mexico Principal Meridian. If the land is not surveyed, contact the OCD Engineering Bureau. Independent subdivision surveys will not be acceptable.

OUTLAND STATE UNIT 136H



SURFACE HOLE LOCATION
& KICK-OFF POINT
401' FNL & 2,330' FWL
ELEV. = 3,684'

NAD 83 X = 821,459.09'
NAD 83 Y = 554,558.43'
NAD 83 LAT = 32.521257°
NAD 83 LONG = -103.424518°
NAD 27 X = 780,276.75'
NAD 27 Y = 554,496.41'
NAD 27 LAT = 32.521133°
NAD 27 LONG = -103.424035°

FIRST TAKE POINT &
PENETRATION POINT 1
100' FNL & 330' FWL

NAD 83 X = 819,456.31'
NAD 83 Y = 554,841.77'
NAD 83 LAT = 32.522082°
NAD 83 LONG = -103.431007°
NAD 27 X = 778,274.03'
NAD 27 Y = 554,779.73'
NAD 27 LAT = 32.521959°
NAD 27 LONG = -103.430524°

PENETRATION POINT 2
2,605' FNL & 330' FWL

NAD 83 X = 819,477.20'
NAD 83 Y = 552,337.10'
NAD 83 LAT = 32.515198°
NAD 83 LONG = -103.431008°
NAD 27 X = 778,294.84'
NAD 27 Y = 552,275.12'
NAD 27 LAT = 32.515074°
NAD 27 LONG = -103.430525°

PENETRATION POINT 3
3,905' FNL & 330' FWL

NAD 83 X = 819,488.06'
NAD 83 Y = 551,037.26'
NAD 83 LAT = 32.511625°
NAD 83 LONG = -103.431008°
NAD 27 X = 778,305.66'
NAD 27 Y = 550,975.31'
NAD 27 LAT = 32.511501°
NAD 27 LONG = -103.430526°

PENETRATION POINT 4
2,639' FSL & 330' FWL

NAD 83 X = 819,498.91'
NAD 83 Y = 549,737.41'
NAD 83 LAT = 32.508052°
NAD 83 LONG = -103.431009°
NAD 27 X = 778,316.47'
NAD 27 Y = 549,675.50'
NAD 27 LAT = 32.507929°
NAD 27 LONG = -103.430527°

LAST TAKE POINT &
BOTTOM HOLE LOCATION
100' FSL & 330' FWL

NAD 83 X = 819,520.30'
NAD 83 Y = 547,198.70'
NAD 83 LAT = 32.501074°
NAD 83 LONG = -103.431009°
NAD 27 X = 778,337.77'
NAD 27 Y = 547,136.85'
NAD 27 LAT = 32.500950°
NAD 27 LONG = -103.430527°

Released to Imaging: 9/15/2025 9:56:11 AM

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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

Form APD Conditions

Permit 394971

PERMIT CONDITIONS OF APPROVAL

Operator Name and Address:	API Number:
Earthstone Operating, LLC [331165] 300 N. Marienfeld St Ste 1000 Midland, TX 79701	30-025-55200 Well: OUTLAND STATE UNIT #136H

OCD Reviewer	Condition
jeffrey.harrison	NSP required if not included in an existing order or not an infill to an appropriate defining well in the same pool and spacing unit.
jeffrey.harrison	No additives containing PFAS chemicals will be added to the drilling fluids or completion fluids used during drilling, completions, or recompletions operations.
jeffrey.harrison	All logs run on the well must be submitted to NMOCD.
jeffrey.harrison	Proposed well is located within the Capitan Aquifer Reef zone. Casing requirements for this area stipulate that the surface and intermediate holes be drilled with fresh water and that casing be set and cemented to surface immediately below the Capitan to isolate it from the rest of the wellbore.
jeffrey.harrison	Cement is required to circulate on both surface and intermediate1 strings of casing.
jeffrey.harrison	If cement does not circulate on any string, a Cement Bond Log (CBL) is required for that string of casing.
jeffrey.harrison	Notify the OCD 24 hours prior to casing & cement.
jeffrey.harrison	File As Drilled C-102 and a directional Survey with C-104 completion packet.
jeffrey.harrison	A [C-103] Sub. Drilling (C-103N) is required within (10) days of spud.
jeffrey.harrison	Once the well is spud, to prevent ground water contamination through whole or partial conduits from the surface, the operator shall drill without interruption through the fresh water zone or zones and shall immediately set in cement the water protection string.
jeffrey.harrison	Oil base muds are not to be used until fresh water zones are cased and cemented providing isolation from the oil or diesel. This includes synthetic oils. Oil based mud, drilling fluids and solids must be contained in a steel closed loop system.

Project: (SP) LEA
Site: OUTLAND STATE PROJECT
Well: OUTLAND STATE UNIT 136H
Wellbore: OWB
Design: PWP0

SECTION DETAILS

Sec	MD	Inc	Azi	TVD	+N/-S	+E/-W	Dleg	TFace	VSect	Annotation
1	0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.0	
2	1500.0	0.00	0.00	1500.0	0.0	0.0	0.00	0.00	0.0	Start Build 2.00
3	2250.0	15.00	278.05	2241.5	13.7	-96.7	2.00	278.05	11.4	Start 7060.9 hold at 2250.0 MD
4	9310.9	15.00	278.05	9061.8	269.7	-1906.1	0.00	0.00	224.8	Start Drop -2.00
5	10060.9	0.00	0.00	9803.2	283.3	-2002.8	2.00	180.00	236.2	Start 919.3 hold at 10060.9 MD
6	10980.2	0.00	0.00	10722.5	283.3	-2002.8	0.00	0.00	236.2	Start DLS 12.00 TFO 179.52
7	11730.2	90.00	179.52	11200.0	-194.1	-1998.8	12.00	179.52	696.9	Start 7165.9 hold at 11730.2 MD
8	18896.0	90.00	179.52	11200.0	-7359.7	-1938.8	0.00	0.00	7610.8	TD at 18896.0

WELL DETAILS: OUTLAND STATE UNIT 136H

3684.0

		Northing	Easting	Latittude	Longitude
0.0	0.0	554558.43	821459.09	32° 31' 16.525 N	103° 25' 28.263 W

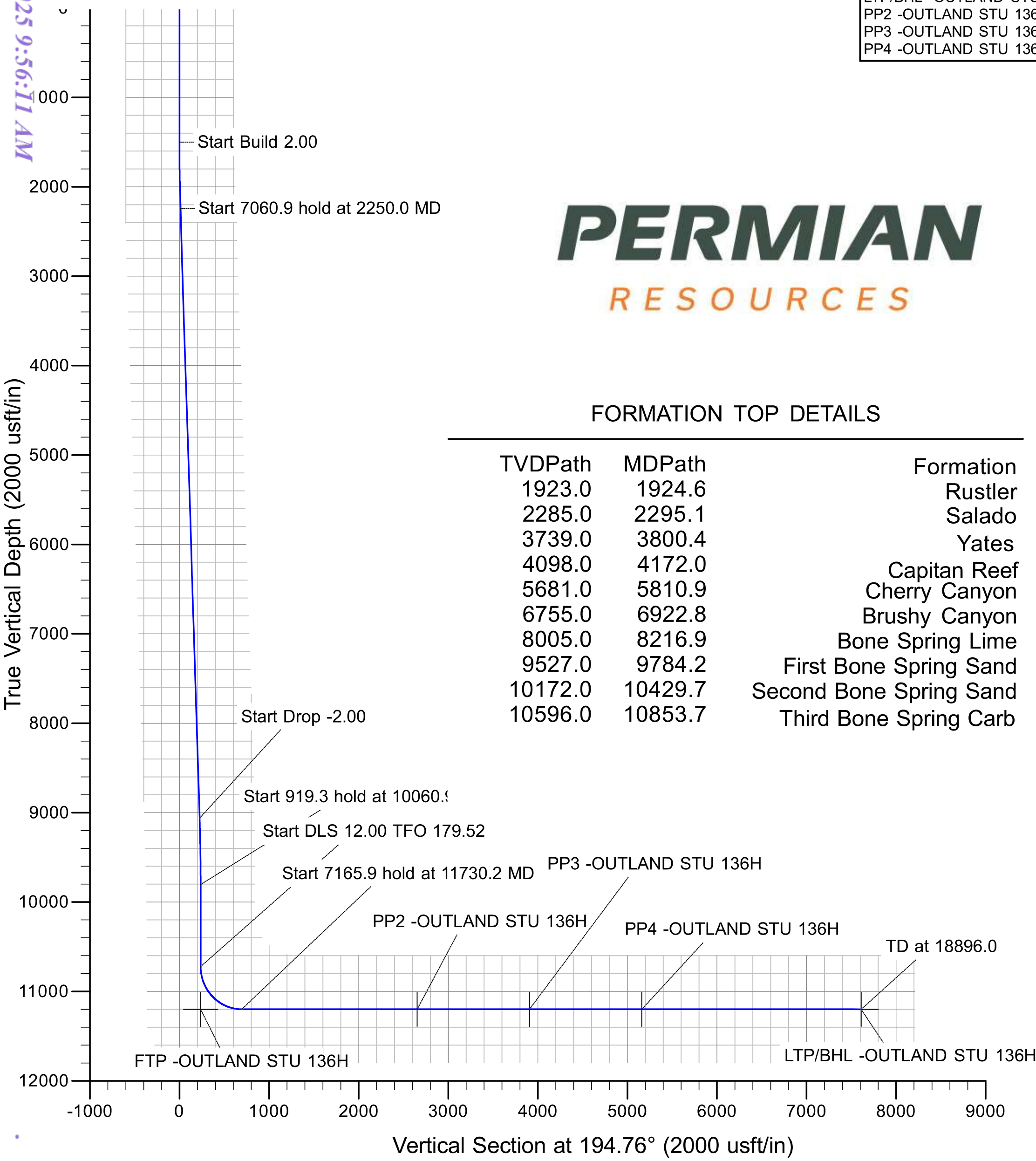
DESIGN TARGET DETAILS

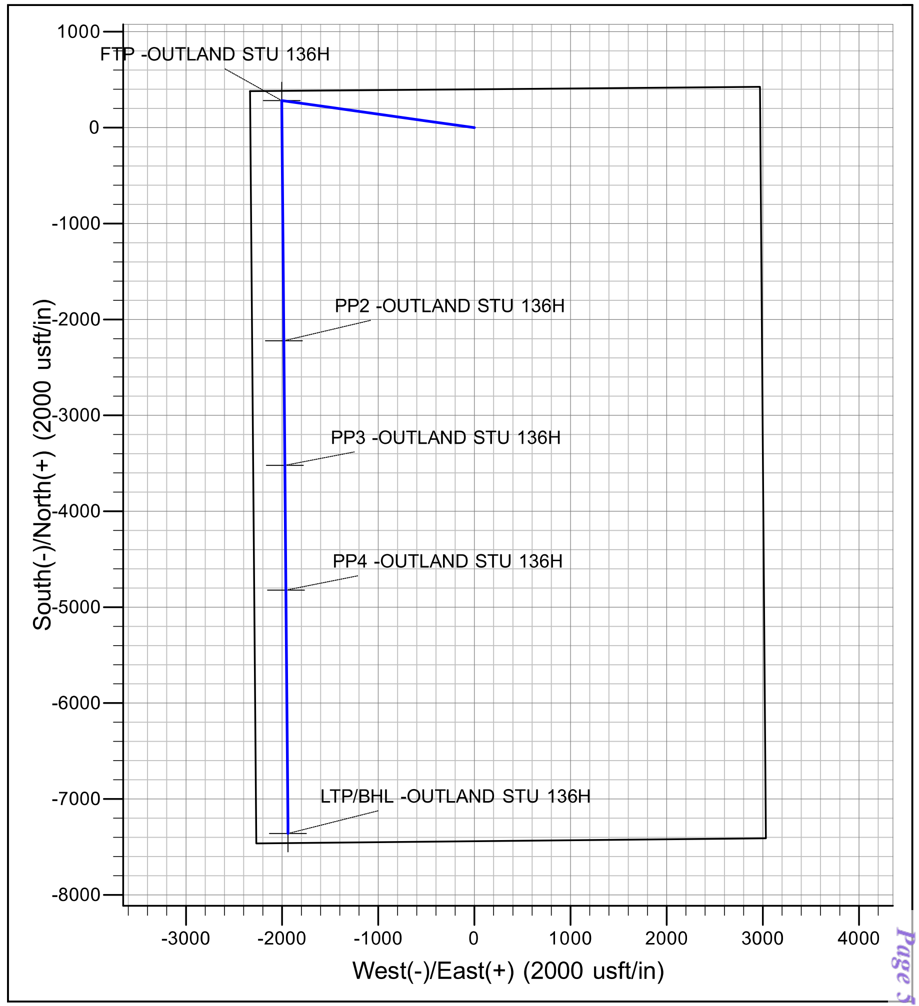
Name	TVD	+N/-S	+E/-W	Northing	Easting	Latitude	Longitude
FTP -OUTLAND STU 136H	11200.0	283.3	-2002.8	554841.77	819456.31	32° 31' 19.497 N	103° 25' 51.624 W
LTP/BHL -OUTLAND STU 136H	11200.0	-7359.7	-1938.8	547198.70	819520.30	32° 30' 3.868 N	103° 25' 51.633 W
PP2 -OUTLAND STU 136H	11200.0	-2221.3	-1981.9	552337.10	819477.20	32° 30' 54.713 N	103° 25' 51.628 W
PP3 -OUTLAND STU 136H	11200.0	-3521.2	-1971.0	551037.26	819488.06	32° 30' 41.851 N	103° 25' 51.630 W
PP4 -OUTLAND STU 136H	11200.0	-4821.0	-1960.2	549737.41	819498.91	32° 30' 28.989 N	103° 25' 51.632 W

PERMIAN RESOURCES

FORMATION TOP DETAILS

TVDPath	MDPath	Formation
1923.0	1924.6	Rustler
2285.0	2295.1	Salado
3739.0	3800.4	Yates
4098.0	4172.0	Capitan Reef
5681.0	5810.9	Cherry Canyon
6755.0	6922.8	Brushy Canyon
8005.0	8216.9	Bone Spring Lime
9527.0	9784.2	First Bone Spring Sand
10172.0	10429.7	Second Bone Spring Sand
10596.0	10853.7	Third Bone Spring Carb





NEW MEXICO

(SP) LEA
OUTLAND STATE PROJECT
OUTLAND STATE UNIT 136H

OWB

Plan: PWP0

Standard Planning Report - Geographic

01 August, 2025

Planning Report - Geographic

Database:	Compass_17	**Local Co-ordinate Reference:**	Well OUTLAND STATE UNIT 136H
Company:	NEW MEXICO	**TVD Reference:**	KB @ 3710.0usft
Project:	(SP) LEA	**MD Reference:**	KB @ 3710.0usft
Site:	OUTLAND STATE PROJECT	**North Reference:**	Grid
Well:	OUTLAND STATE UNIT 136H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OWB		
Design:	PWP0		

Project	(SP) LEA		
Map System:	US State Plane 1983	**System Datum:**	Mean Sea Level
Geo Datum:	North American Datum 1983		
Map Zone:	New Mexico Eastern Zone		

Site	OUTLAND STATE PROJECT					
Site Position:		**Northing:**	537,441.40 usft	**Latitude:**	32° 28' 27.249 N
From:	Map	**Easting:**	820,429.95 usft	**Longitude:**	103° 25' 41.978 W
Position Uncertainty:	0.0 usft	**Slot Radius:**	13-3/16 "		

Well	OUTLAND STATE UNIT 136H						
Well Position	**+N/-S**	0.0 usft	**Northing:**	554,558.43 usft	**Latitude:**	32° 31' 16.525 N
	+E/-W	0.0 usft	**Easting:**	821,459.09 usft	**Longitude:**	103° 25' 28.263 W
Position Uncertainty		0.0 usft	**Wellhead Elevation:**	usft	**Ground Level:**	3,684.0 usft
Grid Convergence:		0.49 °				

Wellbore OWB

Magnetics	**Model Name**	**Sample Date**	**Declination (°)**	**Dip Angle (°)**	**Field Strength (nT)**
	IGRF200510	12/31/2009	7.70	60.54	48,987.19032716

Design PWP0

Audit Notes:

Version:		**Phase:**	PROTOTYPE	**Tie On Depth:**	0.0

Vertical Section:	**Depth From (TVD) (usft)**	**+N/-S (usft)**	**+E/-W (usft)**	**Direction (°)**
	0.0	0.0	0.0	194.76

Plan Survey Tool Program **Date** 8/1/2025

	Depth From (usft)	**Depth To (usft)**	**Survey (Wellbore)**	**Tool Name**	**Remarks**
1	0.0	18,896.0	PWP0 (OWB)	MWD OWSG_Rev2_ MWD - Star	

Plan Sections

Measured Depth (usft)	**Inclination (°)**	**Azimuth (°)**	**Vertical Depth (usft)**	**+N/-S (usft)**	**+E/-W (usft)**	**Dogleg Rate (°/100usft)**	**Build Rate (°/100usft)**	**Turn Rate (°/100usft)**	**TFO (°)**	**Target**
0.0	0.00	0.00	0.0	0.0	0.0	0.00	0.00	0.00	0.00	
1,500.0	0.00	0.00	1,500.0	0.0	0.0	0.00	0.00	0.00	0.00	
2,250.0	15.00	278.05	2,241.5	13.7	-96.7	2.00	2.00	0.00	278.05	
9,310.9	15.00	278.05	9,061.8	269.7	-1,906.1	0.00	0.00	0.00	0.00	
10,060.9	0.00	0.00	9,803.2	283.3	-2,002.8	2.00	-2.00	0.00	180.00	
10,980.2	0.00	0.00	10,722.5	283.3	-2,002.8	0.00	0.00	0.00	0.00	
11,730.2	90.00	179.52	11,200.0	-194.1	-1,998.8	12.00	12.00	23.94	179.52	
18,896.0	90.00	179.52	11,200.0	-7,359.7	-1,938.8	0.00	0.00	0.00	0.00	LTP/BHL -OUTLAN

Planning Report - Geographic

Database:	Compass_17	**Local Co-ordinate Reference:**	Well OUTLAND STATE UNIT 136H
Company:	NEW MEXICO	**TVD Reference:**	KB @ 3710.0usft
Project:	(SP) LEA	**MD Reference:**	KB @ 3710.0usft
Site:	OUTLAND STATE PROJECT	**North Reference:**	Grid
Well:	OUTLAND STATE UNIT 136H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OWB		
Design:	PWP0		

Planned Survey

Measured Depth (usft)	Inclination (°)	Azimuth (°)	Vertical Depth (usft)	+N/-S (usft)	+E/-W (usft)	Map Northing (usft)	Map Easting (usft)	Latitude	Longitude
0.0	0.00	0.00	0.0	0.0	0.0	554,558.43	821,459.09	32° 31' 16.525 N	103° 25' 28.263 W
1,500.0	0.00	0.00	1,500.0	0.0	0.0	554,558.43	821,459.09	32° 31' 16.525 N	103° 25' 28.263 W
Start Build 2.00									
2,250.0	15.00	278.05	2,241.5	13.7	-96.7	554,572.11	821,362.44	32° 31' 16.669 N	103° 25' 29.390 W
Start 7060.9 hold at 2250.0 MD									
9,310.9	15.00	278.05	9,061.8	269.7	-1,906.1	554,828.10	819,552.96	32° 31' 19.354 N	103° 25' 50.497 W
Start Drop -2.00									
10,060.9	0.00	0.00	9,803.2	283.3	-2,002.8	554,841.77	819,456.31	32° 31' 19.497 N	103° 25' 51.624 W
Start 919.3 hold at 10060.9 MD									
10,980.2	0.00	0.00	10,722.5	283.3	-2,002.8	554,841.77	819,456.31	32° 31' 19.497 N	103° 25' 51.624 W
Start DLS 12.00 TFO 179.52									
11,730.2	90.00	179.52	11,200.0	-194.1	-1,998.8	554,364.33	819,460.31	32° 31' 14.773 N	103° 25' 51.625 W
Start 7165.9 hold at 11730.2 MD									
18,896.0	90.00	179.52	11,200.0	-7,359.7	-1,938.8	547,198.70	819,520.30	32° 30' 3.868 N	103° 25' 51.633 W
TD at 18896.0									

Design Targets

Target Name - hit/miss target - Shape	Dip Angle (°)	Dip Dir. (°)	TVD (usft)	+N/-S (usft)	+E/-W (usft)	Northing (usft)	Easting (usft)	Latitude	Longitude
LTP/BHL -OUTLAND	0.00	0.00	11,200.0	-7,359.7	-1,938.8	547,198.70	819,520.30	32° 30' 3.868 N	103° 25' 51.633 W
- plan hits target center									
- Point									
PP4 -OUTLAND STU	0.00	0.00	11,200.0	-4,821.0	-1,960.2	549,737.41	819,498.91	32° 30' 28.989 N	103° 25' 51.632 W
- plan misses target center by 0.1usft at 16357.2usft MD (11200.0 TVD, -4821.0 N, -1960.0 E)									
- Point									
FTP -OUTLAND STU	0.00	0.00	11,200.0	283.3	-2,002.8	554,841.77	819,456.31	32° 31' 19.497 N	103° 25' 51.624 W
- plan misses target center by 197.8usft at 11355.2usft MD (11060.1 TVD, 143.5 N, -2001.6 E)									
- Point									
PP2 -OUTLAND STU	0.00	0.00	11,200.0	-2,221.3	-1,981.9	552,337.10	819,477.20	32° 30' 54.713 N	103° 25' 51.628 W
- plan misses target center by 2027.3usft at 11730.2usft MD (11200.0 TVD, -194.1 N, -1998.8 E)									
- Point									
PP3 -OUTLAND STU	0.00	0.00	11,200.0	-3,521.2	-1,971.0	551,037.26	819,488.06	32° 30' 41.851 N	103° 25' 51.630 W
- plan misses target center by 3327.2usft at 11730.2usft MD (11200.0 TVD, -194.1 N, -1998.8 E)									
- Point									

Planning Report - Geographic

Database:	Compass_17	**Local Co-ordinate Reference:**	Well OUTLAND STATE UNIT 136H
Company:	NEW MEXICO	**TVD Reference:**	KB @ 3710.0usft
Project:	(SP) LEA	**MD Reference:**	KB @ 3710.0usft
Site:	OUTLAND STATE PROJECT	**North Reference:**	Grid
Well:	OUTLAND STATE UNIT 136H	**Survey Calculation Method:**	Minimum Curvature
Wellbore:	OWB		
Design:	PWP0		

Formations

Measured Depth (usft)	Vertical Depth (usft)	Name	Lithology	Dip (°)	Dip Direction (°)
1,924.6	1,923.0	Rustler			
2,295.1	2,285.0	Salado			
3,800.4	3,739.0	Yates			
4,172.0	4,098.0	Capitan Reef			
5,810.9	5,681.0	Cherry Canyon			
6,922.8	6,755.0	Brushy Canyon			
8,216.9	8,005.0	Bone Spring Lime			
9,784.2	9,527.0	First Bone Spring Sand			
10,429.7	10,172.0	Second Bone Spring Sand			
10,853.7	10,596.0	Third Bone Spring Carb			

Plan Annotations

Measured Depth (usft)	Vertical Depth (usft)	Local Coordinates +N/-S (usft)	Local Coordinates +E/-W (usft)	Comment
1,500.0	1,500.0	0.0	0.0	Start Build 2.00
2,250.0	2,241.5	13.7	-96.7	Start 7060.9 hold at 2250.0 MD
9,310.9	9,061.8	269.7	-1,906.1	Start Drop -2.00
10,060.9	9,803.2	283.3	-2,002.8	Start 919.3 hold at 10060.9 MD
10,980.2	10,722.5	283.3	-2,002.8	Start DLS 12.00 TFO 179.52
11,730.2	11,200.0	-194.1	-1,998.8	Start 7165.9 hold at 11730.2 MD
18,896.0	11,200.0	-7,359.7	-1,938.8	TD at 18896.0

Permian Resources - Outland State Unit 136H

1. Geologic Formations

Formation	Elevation	TVD	Target
Rustler	1791	1923	No
Top of Salt	1429	2285	No
Yates	-25	3739	No
Capitan	-384	4098	No
Cherry Canyon	-1967	5681	No
Brushy Canyon	-3041	6755	No
Bone Spring Lime	-4291	8005	No
1st Bone Spring Sand	-5813	9527	No
2nd Bone Spring Sand	-6458	10172	No
3rd Bone Spring Carb	-6882	10596	No
3rd Bone Spring Sand	-7492	11206	Yes

2. Blowout Prevention

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type	x	Tested to:
12.25	13-5/8"	5M	Annular	x	2500 psi
			Blind Ram	x	5000 psi
			Pipe Ram	x	
			Double Ram		
			Other*		
8.75	13-5/8"	5M	Annular	x	2500 psi
			Blind Ram	x	5000 psi
			Pipe Ram	x	
			Double Ram		
			Other*		

Equipment: BOPE with working pressure ratings in excess of anticipated maximum surface pressure will be utilized for well control from drill out of surface casing to TMD. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested. All BOPE connections shall be flanged, welded or clamped. All choke lines shall be straight unless targeted with running tees or tee blocks are used, and choke lines shall be anchored to prevent whip and reduce vibrations. All valves in the choke line & the choke manifold shall be full opening as to not cause restrictions and to allow for straight fluid paths to minimize potential erosion. All gauges utilized in the well control system shall be of a type designed for drilling fluid service. A top drive inside BOP valve will be utilized at all times. Subs equipped with full opening valves sized to fit the drill pipe and collars will be available on the rig floor in the open position. The key to operate said valve equipped subs will be on the rig floor at all times. The accumulator system will have sufficient capacity to open the HCR and close all three sets of rams plus the annular preventer while retaining at least 300 psi above precharge on the closing manifold (accumulator system shall be capable of doing so without using the closing unit pumps). The fluid reservoir capacity will be double the usable fluid volume of the accumulator system capacity, and the fluid level will be maintained at the manufacturer's recommended level. Prior to connecting the closing unit to the BOP stack, an accumulator precharge pressure test shall be performed to ensure the precharge pressure is within 100 psi of the desired precharge pressure (only nitrogen gas will be used to precharge). Two independent power sources will be made available at all times to power the closing unit pumps so that the pumps can automatically start when the closing valve manifold pressure has decreased to the preset level. Closing unit pumps will be sized to allow opening of HCR and closing of annular preventer on 5" drill pipe achieving at least 200 psi above precharge pressure with the accumulator system isolated from service in less than two minutes. A valve shall be installed in the closing line as close to the annular preventer as possible to act as a locking device; the valve shall be maintained in the open position and shall be closed only when the power source for the accumulator system is inoperative. Remote controls capable of opening and closing all preventers & the HCR shall be readily accessible to the driller; master controls with the same capability will be operable at the accumulator. The wellhead will be a multibowl speed head allowing for hangoff of intermediate casing & isolation of the 133/8 x 95/8 annulus without breaking the connection between the BOP & wellhead to install an additional casing head. A wear bushing will be installed & inspected frequently to guard against internal wear to wellhead. VBRs (variablebore rams) will be run in upper rambody of BOP stack to provide redundancy to annular preventer while RIH w/ production casing;

Requesting Variance? YES
Variance request: Flex hose and offline cement variances, see attachments in section 8.
Testing Procedure: The BOP test shall be performed before drilling out of the surface casing shoe and will occur at a minimum: a. when initially installed b. whenever any seal subject to test pressure is broken c. following related repairs d. at 30 day intervals e. checked daily as to mechanical operating conditions. The ram type preventer(s) will be tested using a test plug to 250 psi (low) and 5,000 psi (high) (casinghead WP) with a test plug upon its installation onto the 13 surface casing. If a test plug is not used, the ram type preventer(s) shall be tested to 70% of the minimum internal yield pressure of the casing. The annular type preventer(s) shall be tested to 3500 psi. Pressure will be maintained for at least 10 minutes or until provisions of the test are met, whichever is longer. A Sundry Notice (Form 3160 5), along with a copy of the BOP test report, shall be submitted to the local BLM office within 5 working days following the test. If the bleed line is connected into the buffer tank (header), all BOP equipment including the buffer tank and associated valves will be rated at the required BOP pressure. The BLM office will be provided with a minimum of four (4) hours notice of BOP testing to allow witnessing. The BOP Configuration, choke manifold layout, and accumulator system, will be in compliance with Onshore Order 2 for a 5,000 psi system. A remote accumulator and a multi-bowl system will be used, please see attachment in section 8 for multi-bowl procedure. Pressures, capacities, and specific placement and use of the manual and/or hydraulic controls, accumulator controls, bleed lines, etc., will be identified at the time of the BLM 'witnessed BOP test. Any remote controls will be capable of both opening and closing all preventers and shall be readily accessible.

Choke Diagram Attachemnt: 5 M Choe Manifold
BOP Diagram Attachment: BOP Schematic

3. Casing

String	Hole Size	Casing Size	Top	Bottom	Top TVD	Bottom TVD	Length	Grade	Weight	Connection	Collapse SF	Burst SF	Joint SF Type	Joint SF	Body SF Type	Body SF
Surface	17.5	13.375	0	1948	0	1948	1948	J55	54.5	BTC	1.17	1.47	Dry	4.41	Dry	4.14
Intermediate	12.25	9.625	0	5731	0	5731	5731	J55	40	BTC	2.11	1.39	Dry	2.17	Dry	1.91
Production	8.75	5.5	0	11730	0	11200	11730	P110RY	20	Bushmast	1.82	1.89	Dry	1.98	Dry	1.98
Production	8.5	5.5	11730	18896	11200	11200	7166	P110RY	20	Bushmast	1.82	1.89	Dry	1.98	Dry	1.98
								BLM Min Safety Factor			1.125	1		1.6		1.6

Non API casing spec sheets and casing design assumptions attached.

4. Cement

String	Lead/Tail	Top MD	Bottom MD	Quanity (sx)	Yield	Density	Cu Ft	Excess %	Cement Type	Additives
Surface	lead	0	1550	1150	1.88	12.9	2160	100%	Class C	EconoCem-HLC + 5% Salt + 5% Kol-Seal
Surface	Tail	1550	1948	320	1.34	14.8	420	50%	Class C	Accelerator
Intermediate	Lead	3764	4580	210	1.88	12.9	390	50%	Class C	EconoCem-HLC + 5% Salt + 5% Kol-Seal
Intermediate	Tail	4580	5731	420	1.34	14.8	550	50%	Class C	Retarder
Stage Tool Depth		3764								
Intermediate 2nd Stage	Lead	0	3264	710	1.88	12.9	1330	50%	Class C	EconoCem-HLC + 5% Salt + 5% Kol-Seal
Intermediate 2nd Stage	Tail	3264	3764	160	1.33	14.8	200	25%	Class C	Salt
Production	Lead	5231	10980	830	2.41	11.5	1990	40%	Class H	POZ, Extender, Fluid Loss, Dispersant, Retarder
Production	Tail	10980	18896	1330	1.73	12.5	2290	25%	Class H	POZ, Extender, Fluid Loss, Dispersant, Retarder

Bradenhead Variance ProcedureIntermediate CasingPermian Resources requests to pump a two-stage cement job on the intermediate casingstring with the first stage being pumped conventionally with the calculated top of cement at theCherry Canyon and the second stage performed as a bradenhead squeeze with planned cementfrom the Brushy Canyon to surface. If cement is not visually confirmed to circulate to surface, thefinal ce-ment top after the second stage job will be verified by Echo-meter. If necessary, a top outconsist-ing of 1,500 sack of Class C cement + 3% Salt + Bentonite Gel (2.30 yld, 12.9 ppg) will beexecuted as a contingency. If cement is still unable to circulate to surface, another Echo-meter runwill be performed for cement top verification.Permian Resources will include the Echo-meter verified fluid top and the volume of displacementfluid above the cement slurry in the annulus in all post-drill sundries on wells utilizing this cementprogram.Permian Resources will report to the BLM the volume of fluid (limited to 5 bbls) used to flushintermediate casing valves following backside cementing procedures.Permian Resources requests to pump an Optional Lead if well conditions dictate in an attempt tobring cement inside the surface casing. If cement reaches the desired height, the BLM will benotified and the second stage bradenhead squeeze and subsequent TOC verification will benegated.Permian Resources requests the option to conduct the bradenhead squeeze and TOC verificationoffline as per standard approval from BLM when unplanned remediation is needed and batchdrilling is approved. In the event the bradenhead is conducted, we will ensure the first stagecement job is cemented properly and the well is static with floats holding and no pressure on thecsg annulus as with all other casing strings where batch drilling operations occur before moving offthe rig. The TA cap will also be installed per Cactus procedure and pressure inside the casing willbe monitored via the valve on the TA cap as per standard batch drilling ops.

5. Circulating Medium

Mud System Type: Closed
Will an air or gas system be used: No
Describe what will be on location to control well or mitigate oter conditions: Sufficient quantities of mud materials will be on the well site at all times for the purpose of assuring well control and maintaining wellbore integrity. Surface interval will employ fresh water mud. The intermediate hole will utilize a saturated brine fluid to inhibit salt washout. The production hole will employ brine based and oil base fluid to inhibit formation reactivity and of the appropriate density to maintain well control.

Describe the mud monitoring system utilized: Centrifuge separation system. Open tank monitoring with EDR will be used for drilling fluids and return volumes. Open tank monitoring will be used for cement and cuttings return volumes. Mud properties will be monitored at least every 24 hours using industry accepted

Cuttings Volume: 11690 Cu Ft

Circulating Medium Table

Top Depth	Bottom Depth	Mud Type	Min Weight	Max Weight
0	1948	Spud Mud	8.6	9.5
1948	5731	Water Based Mud	10	10
5731	11730	OBM	9	10.5
11730	18896	OBM	9	10.5

6. Test, Logging, Coring

List of production tests including testing procedures, equipment and safety measures:
Will utilize MWD/LWD (Gamma Ray logging) from intermediate hole to TD of the well.
List of open and cased hole logs run in the well:
DIRECTIONAL SURVEY,GAMMA RAY LOG,
Coring operation description for the well:
N/A

7. Pressure

Anticipated Bottom Hole Pressure	6120	psi
Anticipated Surface Pressure	3651	psi
Anticipated Bottom Hole Temperature	166	°F
Anticipated Abnormal pressure, temp, or geo hazards	No	

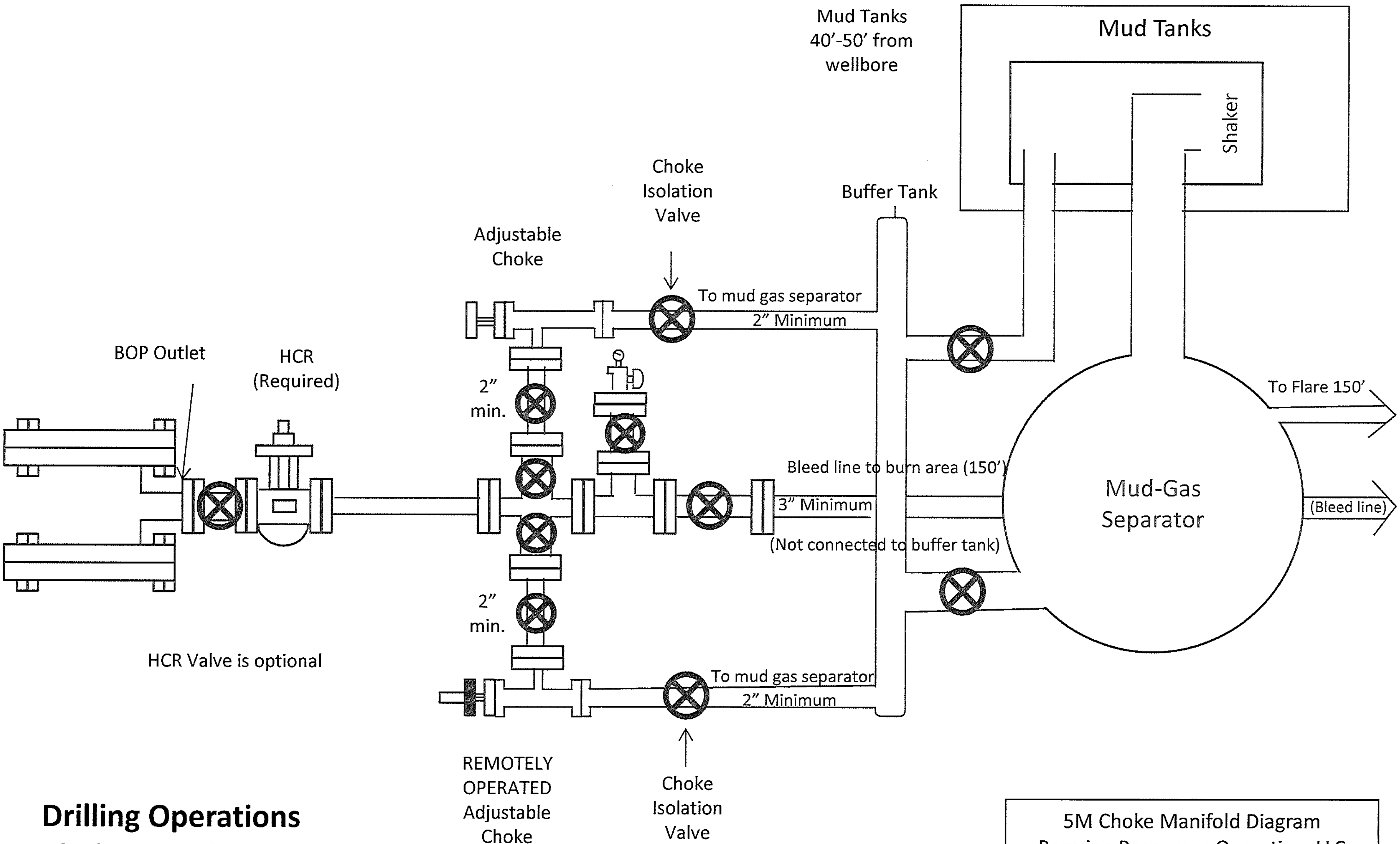
8. Waste Management

Waste Type:	Drilling
Waste content description:	Fresh water based drilling fluid
Amount of waste:	1500 bbls
Waste disposal frequency:	Weekly (after drilling all surfaces)
Safe containment description:	Steel tanks with plastic-lined containment berms
Waste disposal type:	Haul to commercial facility
Disposal location ownership:	Commercial
Waste Type:	**Grey Water & Human Waste**
Waste content description:	Grey Water/Human Waste
Amount of waste:	5000 gallons
Waste disposal frequency:	Weekly
Safe containment description:	Approved waste storage tanks with containment
Waste disposal type:	Haul to commercial facility
Disposal location ownership:	Commercial
Waste Type:	**Garbage**
Waste content description:	General trash/garbage
Amount of waste:	5000 lbs
Waste disposal frequency:	Weekly
Safe containment description:	Enclosed trash trailer
Waste disposal type:	Haul to commercial facility
Disposal location ownership:	Commercial
Waste Type:	**Drilling**
Waste content description:	Drill Cuttings
Amount of waste:	11690 Cu Ft
Waste disposal frequency:	Per well
Safe containment description:	Steel tanks
Waste disposal type:	Haul to commercial facility
Disposal location ownership:	Commercial
Waste Type:	**Drilling**
Waste content description:	Brine water based drilling fluid
Amount of waste:	1500 bbls
Waste disposal frequency:	Monthly
Safe containment description:	Steel tanks with plastic-lined containment berms
Waste disposal type:	Haul to commercial facility
Disposal location ownership:	Commercial

9. Other Information

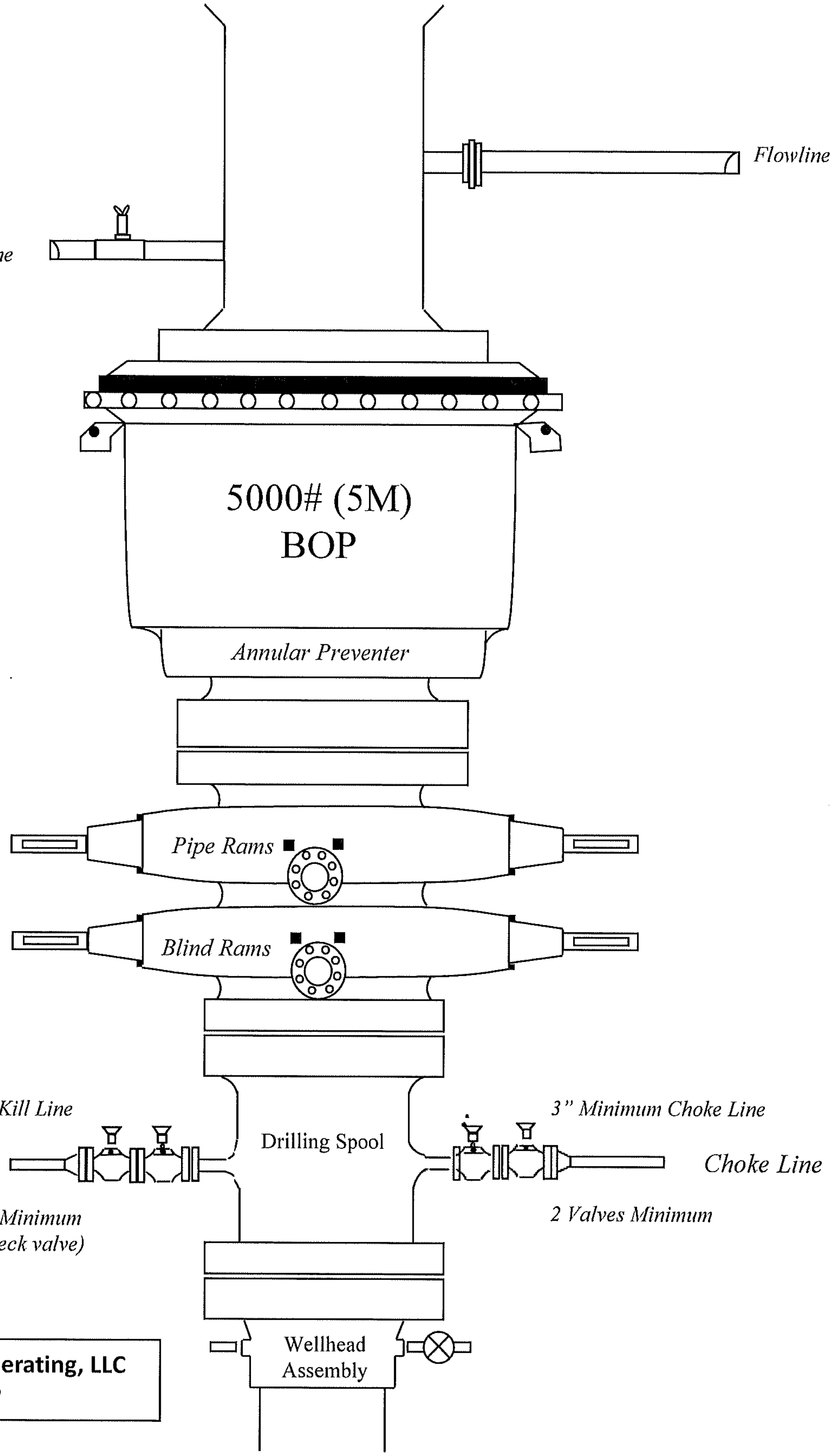
Well Plan and AC Report: attached
Batching Drilling Procedure: attached
WBD: attached
Flex Hose Specs: attached
Offline Cementing Procedure Attached:

Bleed lines will discharge 100' from WH in non-H2S scenarios and 150' from WH in H2S scenarios.



Drilling Operations
Choke Manifold
5M Service

5M Choke Manifold Diagram
Permian Resources Operating, LLC



Permian Resources Operating, LLC
5000# BOP

Bleed lines will discharge 100' from WH in non-H2S scenarios and 150' from WH in H2S scenarios.

Permian Resources
Multi-Well Pad Batch Drilling Procedure

Surface Casing - PR intends to Batch set all surface casing to a depth approved in the APD. Surface Holes will be batch drilled by a rig. Appropriate notifications will be made prior to spudding the well, running and cementing casing and prior to skidding to the rig to the next well on pad.

1. Drill Surface hole to Approved Depth with Rig and perform wellbore cleanup cycles. Trip out and rack back drilling BHA.
2. Run and land planned surface casing see Illustration 1-1 Below to depth approved in APD.
3. Set packoff and test to 5k psi
4. Offline Cement
5. Install wellhead with pressure gauge and nightcap. Nightcap is shown on final wellhead Stack up Illustration #2-2.
6. Skid Rig to adjacent well to drill Surface hole.
7. Surface casing test will be performed by the rig in order to allow ample time for Cement to develop 500psi compressive strength. Casing test to 0.22 psi/ft or 1500 psi whichever is greater - not to exceed 70% casing burst.

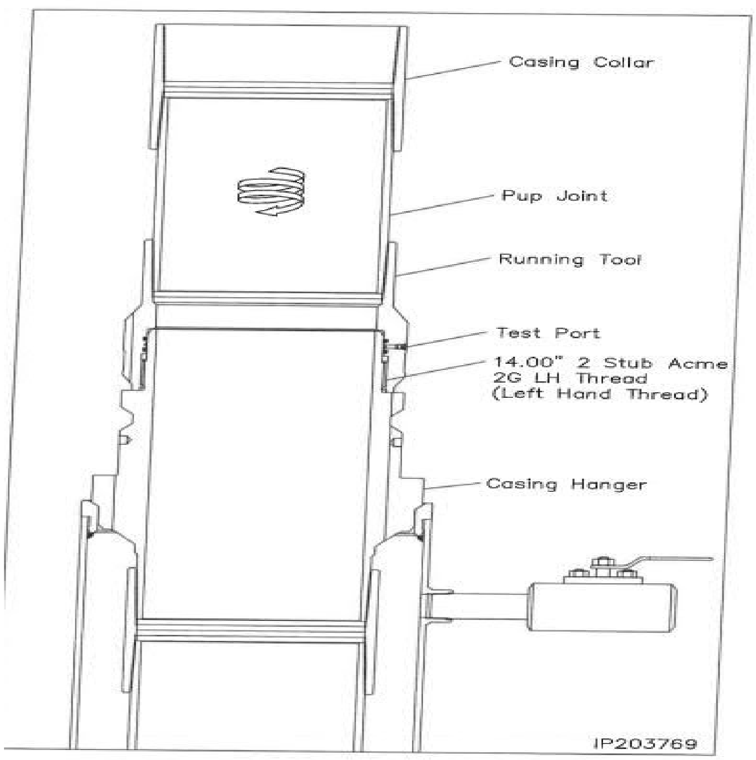
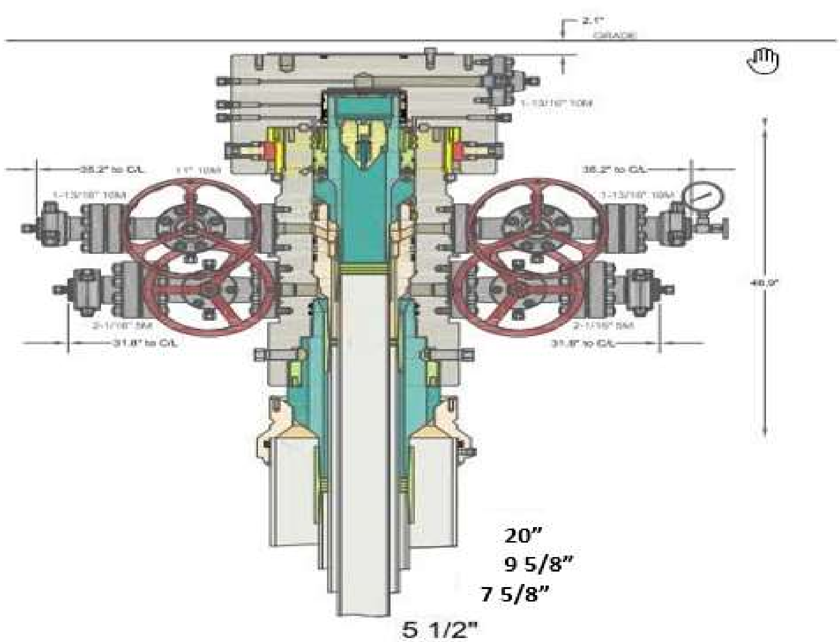


Illustration 1-1

<u>Intermediate Casing</u> – PR intends to Batch set all intermediate casing strings to a depth approved in the APD. Intermediate Holes will be batch drilled by the rig. Appropriate notifications will be made prior to testing BOPE, and prior to running/cementing all casing strings.

1. Rig will remove the nightcap and install and test BOPE.
2. Test Surface casing per COA WOC timing (.22 psi/ft or 1500 psi whichever is greater) - not to exceed 70% casing burst. Cement must have achieved 500psi compressive strength prior to test.
3. Install wear bushing then drill out surface casing shoe-track plus 20’ and conduct FIT to minimum of the MW equivalent anticipated to control the formation pressure to the next casing point.
4. Drill Intermediate hole to approved casing point. Trip out of hole with BHA to run Casing.
5. Remove wear bushing then run and land Intermediate Casing with mandrel hanger in wellhead.
6. Cement casing to surface with floats holding.
7. Washout stack then run wash tool in wellhead and wash hanger and pack-off setting area.
8. Install pack-off and test void to 5,000 psi for 15 minutes. Nightcap shown on final wellhead stack up illustration 2-2 on page 3.
9. Test casing per COA WOC timing (.22 psi/ft or 1500 psi whichever is greater) - not to exceed 70% casing burst. Cement must have achieved 500psi compressive strength prior to test.
10. Install nightcap – skid rig to adjacent well to drill Intermediate hole.



SKID PHASE

Illustration 2-2

Production Casing – PR intends to Batch set all Production casings with Rig. Appropriate notifications will be made prior Testing BOPE, and prior to running/cementing all casing strings.

1. Drilling Rig will remove the nightcap and install and test BOPE.
2. Install wear bushing then drill Intermediate shoe-track plus 20' and conduct FIT to minimum MW equivalent to control the formation pressure to TD of well.
3. Drill Vertical hole to KOP – Trip out for Curve BHA.
4. Drill Curve, landing in production interval – Trip for Lateral BHA.
5. Drill Lateral / Production hole to Permitted BHL, perform cleanup cycles and trip out to run Production Casing.
6. Remove wear bushing then run Production casing to TD landing casing mandrel in wellhead.
7. Cement Production string with floats holding.
8. Run in with wash tool and wash wellhead area – install pack-off and test void to 5,000psi for 15 minutes.
9. Install BPV in Production mandrel hanger – Nipple down BOPE and install nightcap.
10. Test nightcap void to 5,000 psi for 30 minutes per illustration 2-2
11. Skid rig to adjacent well on pad to drill production hole.

Permian Resources
BOP Break Testing Variance Procedure

Subject: Request for a Variance Allowing break Testing of the Blowout Preventer Equipment (BOPE). Permian Resources requests a variance to ONLY test broken pressure seals on the BOPE and function test BOP when skidding a drilling rig between multiple wells on a pad.

Background

Title 43 CFR 3172, Drilling Operations, Sections 6.b.9.iv states that the BOP test must be performed whenever any seal subject to test pressure is broken. The current interpretation of the Bureau of Land Management (BLM) requires a complete BOP test and not just a test of the affected component. 43 CFR 3172.13, Variances from minimum standards states, "An operator may request the authorized officer to approve a variance from any of the minimum standards prescribed in §§ 3172.6 through 3172.12. All such requests shall be submitted in writing to the appropriate authorized officer and provide information as to the circumstances which warrant approval of the variance(s) requested and the proposed alternative methods by which the related minimum standard(s) are to be satisfied. The authorized officer, after considering all relevant factors, if appropriate, may approve the requested variance(s) if it is determined that the proposed alternative(s) meet or exceed the objectives of the applicable minimum standard(s).". Permian Resources feels the break testing the BOPE is such a situation. Therefore, as per 43 CFR 3172.13, Permian Resources submits this request for the variance.

Supporting Documentation

The language used in 43 CFR 3172 became effective on December 19, 1988 and has remained the standard for regulating BLM onshore drilling operations for over 30 years. During this time, there have been significant changes in drilling technology. The BLM continues to use the variance request process to allow for the use of modern technology and acceptable engineering practices that have arisen since 43 CFR 3172 was originally released. The Permian Resources drilling rig fleet has many modern upgrades that allow the intact BOP stack to be moved between well slots on a multi-well pad, as well as, wellhead designs that incorporate quick connects facilitating release of the BOP from the wellhead without breaking any BOP stack components apart. These technologies have been used extensively offshore, and other regulators, API, and many operators around the world have endorsed break testing as safe and reliable.

Figure 1: Winch System attached to BOP Stack

Figure 2: BOP Winch System

American Petroleum Institute (API) standards, specification and recommended practices are considered the industry standard and are consistently utilized and referenced by the industry. 43 CFR 3172 recognizes API recommended Practices (RP) 53 in its original development. API Standard 53, Well Control Equipment Systems for Drilling Wells (Fifth Edition, December 2018, Annex C, Table C.4) recognizes break testing as an acceptable practice. Specifically, API Standard 53, Section 5.3.7.1 states "A pressure test of the pressure containing component shall be performed following the disconnection or repair, limited to the affected component." See Table C.4 below for reference.

62 API STANDARD 53

Table C.4—Initial Pressure Testing, Surface BOP Stacks

Component to be Pressure Tested	Pressure Test—Low Pressure[ac] psig (MPa)	Pressure Test—High Pressure[ac] Change Out of Component, Elastomer, or Ring Gasket	Pressure Test—High Pressure[ac] No Change Out of Component, Elastomer, or Ring Gasket
Annular preventer[b]	250 to 350 (1.72 to 2.41)	RWP of annular preventer	MASP or 70% annular RWP, whichever is lower.
Fixed pipe, variable bore, blind, and BSR preventers[ac]	250 to 350 (1.72 to 2.41)	RWP of ram preventer or wellhead system, whichever is lower	ITP
Choke and kill line and BOP side outlet valves below ram preventers (both sides)	250 to 350 (1.72 to 2.41)	RWP of side outlet valve or wellhead system, whichever is lower	ITP
Choke manifold—upstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of ram preventers or wellhead system, whichever is lower	ITP
Choke manifold—downstream of chokes[e]	250 to 350 (1.72 to 2.41)	RWP of valve(s), line(s), or MASP for the well program, whichever is lower	
Kelly, kelly valves, drill pipe safety valves, IBOPs	250 to 350 (1.72 to 2.41)	MASP for the well program	

[a] Pressure test evaluation periods shall be a minimum of five minutes.
No visible leaks.
The pressure shall remain stable during the evaluation period. The pressure shall not decrease below the intended test pressure.

[b] Annular(s) and VBR(s) shall be pressure tested on the largest and smallest OD drill pipe to be used in well program.

[c] For pad drilling operations, moving from one wellhead to another within the 21 days, pressure testing is required for pressure-containing and pressure-controlling connections when the integrity of a pressure seal is broken.

[d] For surface offshore operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented during the initial test. For land operations, the ram BOPs shall be pressure tested with the ram locks engaged and the closing and locking pressure vented at commissioning and annually.

[e] Adjustable chokes are not required to be full sealing devices. Pressure testing against a closed choke is not required.

The Bureau of Safety and Environmental Enforcement (BSEE), Department of Interior, has also utilized the API standards, specification and best practices in the development of its offshore oil and gas regulations and incorporates them by reference within its regulations.

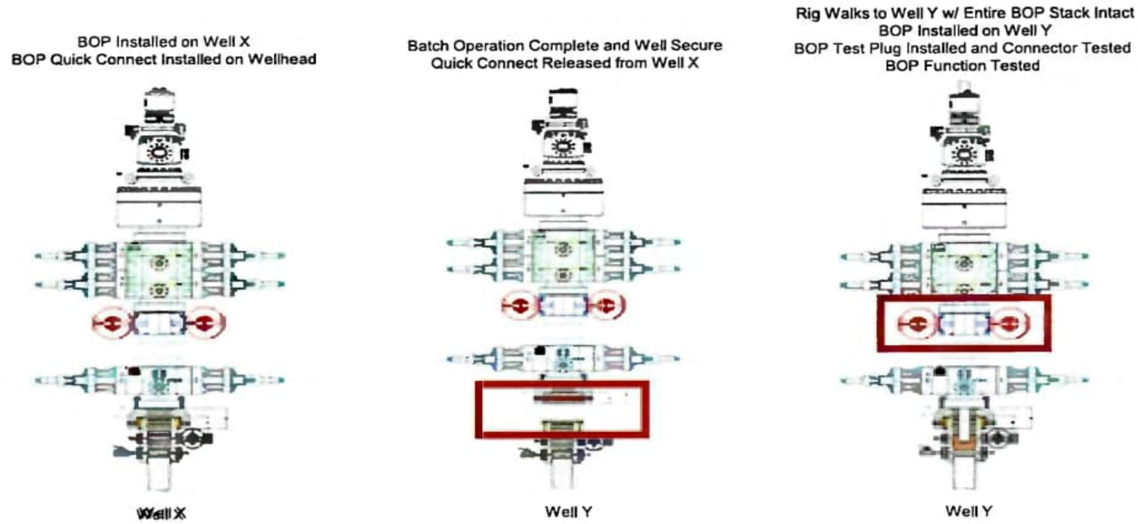
Break testing has been approved by the BLM in the past with other operators based on the detailed information provided in this document.

Permian Resources feels break testing and our current procedures meet the intent of 43 CFR 3172 and often exceed it. There has been no evidence that break testing results in more components failing than seen on full BOP tests. Permian Resources internal standards require complete BOPE tests more often than that of 43 CFR 3172 (every 21 days). In addition to function testing the annular, pipe rams and blind rams after each BOP nipple up, Permian Resources performs a choke drill with the rig crew prior to drilling out every casing shoe. This is additional training for the rig crew that exceeds the requirements of 43 CFR 3172.

<u>Procedures</u>

1) Permian Resources will use this document for our break testing plan for New Mexico Delaware Basin. The summary below will be referenced in the APD or Sundry Notice and receive approval prior to implementing this variance.
2) Permian Resources will perform BOP break testing on multi-wells pads where multiple intermediate sections can be drilled and cased within the 21-day BOP test window.
   a)A full BOP test will be conducted on the first well on the pad.
   b)The first intermediate hole section drilled on the pad will be the deepest. All the remaining hole sections will be the same formation depth or shallower.
   c) A full BOP test will be required if the intermediate hole section being drilled has a MASP over 5M.
   d) A full BOP test will be required prior to drilling any production hole.
3) After performing a complete BOP test on the first well, the intermediate hole section will be drilled and cased, two breaks would be made on the BOP equipment.
   a) Between the HCV valve and choke line connection
   b)Between the BOP quick connect and the wellhead
4) The BOP is then lifted and removed from the wellhead by a hydraulic system.
5) After skidding to the next well, the BOP is moved to the wellhead by the same hydraulic system and installed.
6) The connections mentioned in 3a and 3b will then be reconnected.
7) Install test plug into the wellhead using test joint or drill pipe.
8) A shell test is performed against the upper pipe rams testing the two breaks.
9) The shell test will consist of a 250 psi low test and a high test to the value submitted in the APD or Sundry (e.g. 5,000 psi or 10,000psi).
10) Function tests will be performed on the following components: lower pipe rams, blind rams, and annular.
11) For a multi-well pad the same two breaks on the BOP would be made and on the next wells and steps 4 through 10 would be repeated.
12) A second break test would only be done if the intermediate hole section being drilled could not be completed within the 21 day BOP test window.

Note: Picture below highlights BOP components that will be tested during batch operations



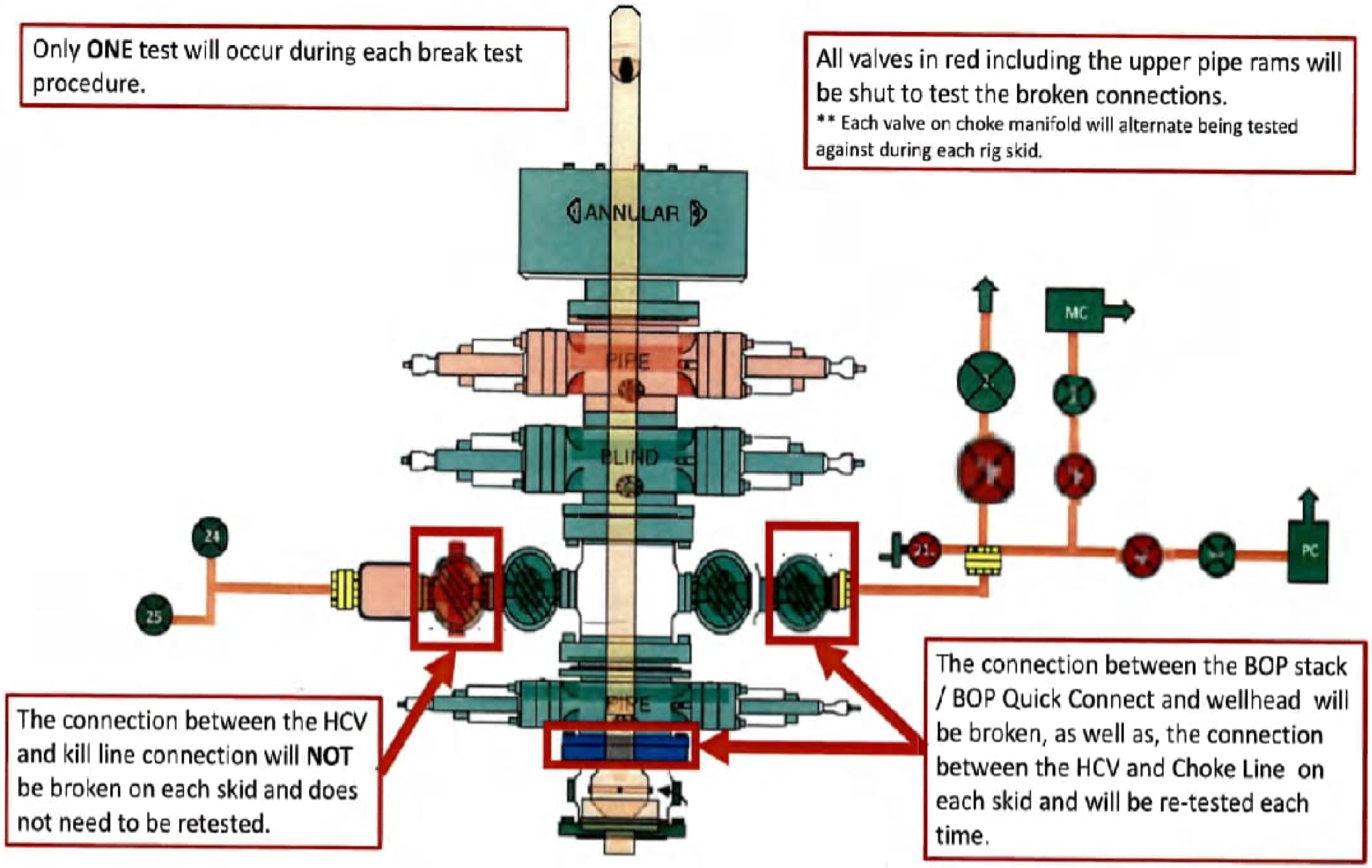
<u>Summary</u>

A variance is requested to ONLY test broken pressure seals on the BOP equipment when moving from wellhead to wellhead which is in compliance with API Standard 53. API Standard 53 states, that for pad drilling operations, moving from one wellhead to another within 21 days, pressure testing is required for pressure-containing and pressure-controlling connections when the integrity of a pressure seal is broken.

The BOP will be secured by a hydraulic carrier or cradle. The BLM will be contacted if a Well Control
event occurs prior to the commencement of a BOPE Break Testing operation.

Based on public data and the supporting documentation submitted herein to the BLM, we will request permission to ONLY retest broken pressure seals if the following conditions are met:

1) After a full BOP test is conducted on the first well on the pad.
2) The first intermediate hole section drilled on the pad will be the deepest. All the remaining hole sections will be the same depth or shallower.
3) A full BOP test will be required if the intermediate hole section being drilled has a MASP over 5M.
4) A full BOP test will be required prior to drilling the production hole.


Only **ONE** test will occur during each break test procedure.
All valves in red including the upper pipe rams will be shut to test the **broken** connections.
** Each valve on choke manifold will alternate being tested against during each rig skid.
ANNULAR
PIPE
BLIND
PIPE
MC
PC
21
24
25
The connection between the HCV and kill line connection will **NOT** be broken on each skid and does not need to be retested.
The connection between the BOP stack / BOP Quick Connect and wellhead will be broken, as well as, the connection between the HCV and Choke Line on each skid and will be re-tested each time.

Continental

ContiTech Fluid Technology

ContiTech Oil & Marine Corp. # 11535 Brittmoore Park Dr., Houston, TX 77041-6916 USA

CONSIGNEE / Ship-to address:

HELMERICH & PAYNE INT'L DRILLING CO
ATTN: FLEX RIG WHSE - B-BAY
210 MAGNOLIA DRIVE
GALENA PARK TX 77547

Buyer:

HELMERICH & PAYNE INT'L DRILLING CO
1437 SOUTH BOULDER
74119 TULSA

Conditions

Incoterms EXW Houston
Ex Works

Packing list / Delivery note

Document No.	**71461553**
Document Date	28.01.2022
Customer Number	11697
Customer VAT No.	
Supplier Number	
Purchase Order No.	740362040
Purchase Order Date	18.01.2022
Sales Order Number	1388153
Sales Order Date	18.01.2022
Unloading Point	
RAN-No.	

Page 1 of 2

Weights (Gross / Net)
Total Gross Weight 2,507.000 LB
Total Net Weight 2,507.000 LB

Item	Material/Description	Quantity	Net Weight	Gross Weight
	Buyer: Jack Peebles *E-mail: Jackie.Peebles@hpinc.com* *Tel: 832-782-6000* *Rig/Whse: HOW*			
20	00RECERTIFY Recert of HP Hoses Serial# 67094 Commodity Code: 3" X 35 FT 10K Choke & Kill Hoses API 16C End 1: 4 - 1/16" 10Kpsi API Spec 6A Type 6BX Flange End 2: 4 - 1/16" 10Kpsi API Spec 6A Type 6BX Flange c/w BX155 ring groove each end Standard: API Spec 16C - Monogrammed Working Pressure: 10,000psi Test Pressure: 15,000psi Inspection & Certification includes: External inspection of the hose & couplings Internal boroscopic inspection of hose liner Hydrostatic pressure test of hose assembly Repair of any external damage to hose body and end connections (limited to minor repairs). Clean & protect end connections Inspection Report Disposal of hose assembly if hose fails inspection and recertification process. Please Flush Hoses before sending them to our Facility.	1 PC	2,507.000 LB	2,507.000 LB

88000240
Y106-01-01-01
2.9.22

Record Rotary Hose sleeve number on the CBC Made Hose List !!!!!!!!!!!!!!!!!!!!!!!!!!!!

Continental

ContiTech

Hydrostatic Test Certificate

Certificate Number	COM Order Reference	Customer Name & Address
H100122	1388153	HELMERICH & PAYNE DRILLING CO
Customer Purchase Order No:	740362040	1434 SOUTH BOULDER AVE TULSA, OK 74119
Project:		USA

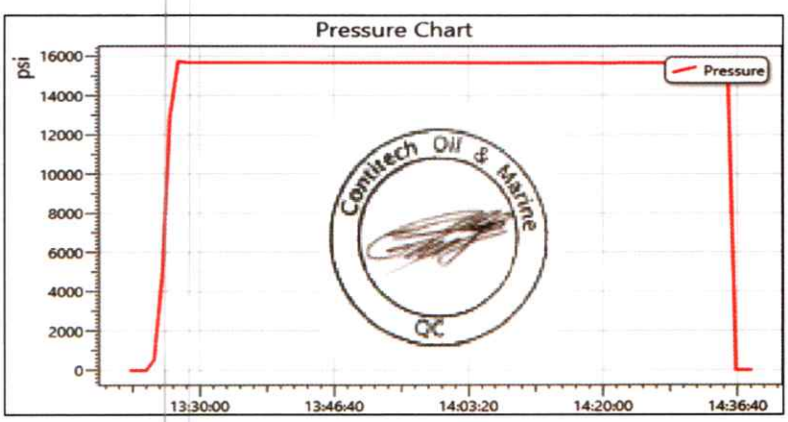
Test Center Address	Accepted by COM Inspection		Accepted by Client Inspection
ContiTech Oil & Marine Corp. 11535 Brittmoore Park Drive Houston, TX 77041 USA	Signed: Date:	Gerson Mejia-Lazo 02/09/22	

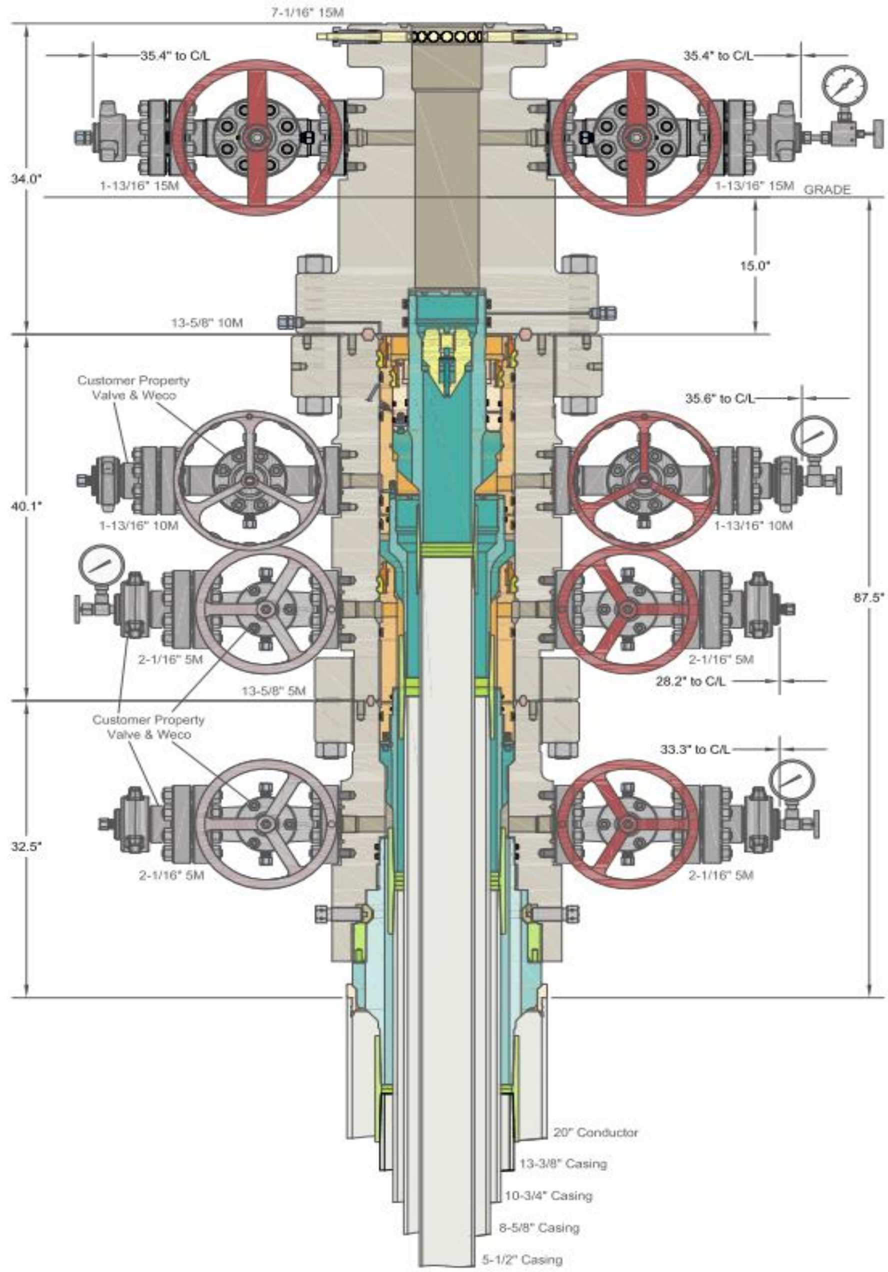
We certify that the goods detailed hereon have been inspected as described below by our Quality Management System, and to the best of our knowledge are found to conform the requirements of the above referenced purchase order as issued to ContiTech Oil & Marine Corporation.

Item	Part No.	Description	Qnty	Serial Number	Work. Press. (psi)	Test Press. (psi)	Test Time (minutes)
20	RECERTIFICATION	3" ID 10K Choke and Kill Hose x 35ft OAL	1	67094	10,000	15,000	60

Record Information	
Start Time	1/27/2022 13:21:21
End Time	1/27/2022 14:38:28
Interval	00:01:00
Number	78
MaxValue	15849
MinValue	-3
AvgValue	14240
RecordName	67094-sh
RecordNumber	199

Gauge Information	
Model	ADT680
SN	21817380014
Range	(0-40000)psi
Unit	psi





ALL DIMENSIONS APPROXIMATE

CACTUS WELLHEAD LLC	PERMIAN RESOURCES NEW MEXICO		
20" x 13-3/8" x 10-3/4" x 8-5/8" x 5-1/2" MBU-4T-CFL-R-DBLO Sys. With 13-5/8" 10M x 7-1/16" 15M CTH-DBLHPS Tubing Head And 10-3/4" & 7-5/8" & 5-1/2" Fluted Mandrel Casing Hangers	DRAWN	DLE	26OCT23
	APPRV		
	DRAWING NO.	HBE0001038	

State of New Mexico
Energy, Minerals and Natural Resources Department

Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Submit Electronically
Via E-permitting

NATURAL GAS MANAGEMENT PLAN

This Natural Gas Management Plan must be submitted with each Application for Permit to Drill (APD) for a new or recompleted well.

Section 1 – Plan Description

Effective May 25, 2021

I. Operator: EARTHSTONE OPERATING, LLC **OGRID:** 331165 **Date:** 08/01/2025

II. Type: ☒ Original ☐ Amendment due to ☐ 19.15.27.9.D(6)(a) NMAC ☐ 19.15.27.9.D(6)(b) NMAC ☐ Other.
If Other, please describe: ______________________________

III. Well(s): Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	ULSTR	Footages	Anticipated Oil BBL/D	Anticipated Gas MCF/D	Anticipated Produced Water BBL/D
See Attached						

IV. Central Delivery Point Name: OUTLAND 1-12 CTB [See 19.15.27.9(D)(1) NMAC]

V. Anticipated Schedule: Provide the following information for each new or recompleted well or set of wells proposed to be drilled or proposed to be recompleted from a single well pad or connected to a central delivery point.

Well Name	API	Spud Date	TD Reached Date	Completion Commencement Date	Initial Flow Back Date	First Production Date
See Attached						

VI. Separation Equipment: ☒ Attach a complete description of how Operator will size separation equipment to optimize gas capture.

VII. Operational Practices: ☒ Attach a complete description of the actions Operator will take to comply with the requirements of Subsection A through F of 19.15.27.8 NMAC.

VIII. Best Management Practices: ☒ Attach a complete description of Operator's best management practices to minimize venting during active and planned maintenance.

Section 2 – Enhanced Plan
EFFECTIVE APRIL 1, 2022

Beginning April 1, 2022, an operator that is not in compliance with its statewide natural gas capture requirement for the applicable reporting area must complete this section.

X☐ Operator certifies that it is not required to complete this section because Operator is in compliance with its statewide natural gas capture requirement for the applicable reporting area.

IX. Anticipated Natural Gas Production:

Well	API	Anticipated Average Natural Gas Rate MCF/D	Anticipated Volume of Natural Gas for the First Year MCF

X. Natural Gas Gathering System (NGGS):

Operator	System	ULSTR of Tie-in	Anticipated Gathering Start Date	Available Maximum Daily Capacity of System Segment Tie-in

XI. Map. ☐ Attach an accurate and legible map depicting the location of the well(s), the anticipated pipeline route(s) connecting the production operations to the existing or planned interconnect of the natural gas gathering system(s), and the maximum daily capacity of the segment or portion of the natural gas gathering system(s) to which the well(s) will be connected.

XII. Line Capacity. The natural gas gathering system ☐ will ☐ will not have capacity to gather 100% of the anticipated natural gas production volume from the well prior to the date of first production.

XIII. Line Pressure. Operator ☐ does ☐ does not anticipate that its existing well(s) connected to the same segment, or portion, of the natural gas gathering system(s) described above will continue to meet anticipated increases in line pressure caused by the new well(s).

☐Attach Operator's plan to manage production in response to the increased line pressure.

XIV. Confidentiality: ☐ Operator asserts confidentiality pursuant to Section 71-2-8 NMSA 1978 for the information provided in Section 2 as provided in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and attaches a full description of the specific information for which confidentiality is asserted and the basis for such assertion.

Section 3 – Certifications
Effective May 25, 2021

Operator certifies that, after reasonable inquiry and based on the available information at the time of submittal:

☒ Operator will be able to connect the well(s) to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system; or

☐ Operator will not be able to connect to a natural gas gathering system in the general area with sufficient capacity to transport one hundred percent of the anticipated volume of natural gas produced from the well(s) commencing on the date of first production, taking into account the current and anticipated volumes of produced natural gas from other wells connected to the pipeline gathering system. ***If Operator checks this box, Operator will select one of the following:***

WELL NAME	API	UL/SECT/T/R	FOOTAGES	ANTICIPATED OIL BBL/D	ANTICIPATED GAS MCF/D	ANTICIPATED WATER BBL/D
ESCOPETA STATE 121H		LOT 2-2-21S-34E	505' FNL, 1632' FEL	1500	1900	3500
OUTLAND STATE UNIT 123H		LOT 3-1-21S-34E	401' FNL, 2264' FWL	1500	1900	3500
OUTLAND STATE UNIT 124H		LOT 3-1-21S-34E	401' FNL, 2297' FWL	1500	1900	3500
OUTLAND STATE UNIT 125H		LOT 2-1-21S-34E	591' FNL, 1465' FEL	1500	1900	3500
OUTLAND STATE UNIT 126H		LOT 2-1-21S-34E	565' FNL, 1444' FEL	1500	1900	3500
OUTLAND STATE UNIT 130H		K-2-21S-34E	2053' FSL, 1704' FWL	1700	2000	4000
OUTLAND STATE UNIT 133H		K-2-21S-34E	2086' FSL, 1704' FWL	1700	2000	4000
OUTLAND STATE UNIT 134H		LOT 2-2-21S-34E	528' FNL, 1608' FEL	1700	2000	4000
OUTLAND STATE UNIT 135H		LOT 2-2-21S-34E	551' FNL, 1585' FEL	1700	2000	4000
OUTLAND STATE UNIT 136H		LOT 3-1-21S-34E	401' FNL, 2330' FWL	1700	2000	4000
OUTLAND STATE UNIT 137H		LOT 3-1-21S-34E	401' FNL, 2363' FWL	1700	2000	4000
OUTLAND STATE UNIT 138H		LOT 2-1-21S-34E	539' FNL, 1424' FEL	1700	2000	4000
OUTLAND STATE UNIT 139H		LOT 2-1-21S-34E	513' FNL, 1404' FEL	1700	2000	4000

WELL NAME	API	SPUD	TD	COMPLETION DATE	FLOW BACK DATE	FIRST PRODUCTION
ESCOPETA STATE 121H	PENDING	11/3/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 123H	PENDING	9/24/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 124H	PENDING	9/24/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 125H	PENDING	9/11/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 126H	PENDING	9/11/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 130H	PENDING	11/10/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 133H	PENDING	11/10/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 134H	PENDING	11/3/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 135H	PENDING	11/3/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 136H	PENDING	9/24/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 137H	PENDING	9/24/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 138H	PENDING	9/11/2025	TBD	TBD	TBD	TBD
OUTLAND STATE UNIT 139H	PENDING	9/11/2025	TBD	TBD	TBD	TBD

Well Shut-In. ☐ Operator will shut-in and not produce the well until it submits the certification required by Paragraph (4) of Subsection D of 19.15.27.9 NMAC; or

Venting and Flaring Plan. ☐ Operator has attached a venting and flaring plan that evaluates and selects one or more of the potential alternative beneficial uses for the natural gas until a natural gas gathering system is available, including:

(a) power generation on lease;
(b) power generation for grid;
(c) compression on lease;
(d) liquids removal on lease;
(e) reinjection for underground storage;
(f) reinjection for temporary storage;
(g) reinjection for enhanced oil recovery;
(h) fuel cell production; and
(i) other alternative beneficial uses approved by the division.

Section 4 - Notices

1. If, at any time after Operator submits this Natural Gas Management Plan and before the well is spud:

(a) Operator becomes aware that the natural gas gathering system it planned to connect the well(s) to has become unavailable or will not have capacity to transport one hundred percent of the production from the well(s), no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised venting and flaring plan containing the information specified in Paragraph (5) of Subsection D of 19.15.27.9 NMAC; or

(b) Operator becomes aware that it has, cumulatively for the year, become out of compliance with its baseline natural gas capture rate or natural gas capture requirement, no later than 20 days after becoming aware of such information, Operator shall submit for OCD's approval a new or revised Natural Gas Management Plan for each well it plans to spud during the next 90 days containing the information specified in Paragraph (2) of Subsection D of 19.15.27.9 NMAC, and shall file an update for each Natural Gas Management Plan until Operator is back in compliance with its baseline natural gas capture rate or natural gas capture requirement.

2. OCD may deny or conditionally approve an APD if Operator does not make a certification, fails to submit an adequate venting and flaring plan which includes alternative beneficial uses for the anticipated volume of natural gas produced, or if OCD determines that Operator will not have adequate natural gas takeaway capacity at the time a well will be spud.

I certify that, after reasonable inquiry, the statements in and attached to this Natural Gas Management Plan are true and correct to the best of my knowledge and acknowledge that a false statement may be subject to civil and criminal penalties under the Oil and Gas Act.

Signature:	Jennifer Elrod
Printed Name:	JENNIFER ELROD
Title:	SR. REGULATORY ANALYST
E-mail Address:	JELROD@NTGLOBAL.COM
Date: 08/01/2025	
Phone:	940-452-6214

OIL CONSERVATION DIVISION **(Only applicable when submitted as a standalone form)**
Approved By:
Title:
Approval Date:
Conditions of Approval:

Permian Resources Operating, LLC (372165)

EARTHSTONE OPERATING, LLC (331165)

Natural Gas Management Plan Descriptions

VI. Separation Equipment:

Permian/Earthstone utilizes a production forecast from our Reservoir Engineering team to appropriately size each permanent, 3-phase separator and heater treater utilized for production operations. Our goal is to maintain 5 minutes of retention time in the test vessel and 20 minutes in the heater treater at peak production rates. The gas produced is routed from the separator to the gas sales line.

VII. Operational Practices:

Drilling

During Permian's/Earthstone's drilling operations it is uncommon for venting or flaring to occur. If flaring is needed due to safety concerns, gas will be routed to a flare and volumes will be estimated.

Flowback

During completion/recompletion flowback operations, after separation flowback begins and as soon as it is technically feasible, Permian/Earthstone routes gas though a permanent separator and the controlled facility where the gas is either sold or flared through a high-pressure flare if needed.

Production

Per 19.15.27.8.D, Permian's/Earthstone's facilities are designed to minimize waste. Our produced gas will only be vented or flared in an emergency or malfunction situation, except as allowed for normal operations noted in 19.15.27.8.D(2) & (4). All gas that is flared is metered. All gas that may be vented will be estimated.

Performance Standards

Permian/Earthstone utilizes a production forecast from our Reservoir Engineering team to appropriately size each permanent, 3-phase separator and heater treater utilized for production operations.

All of Permian's/Earthstone's permanent storage tanks associated with production operations which are routed to a flare or control device are equipped with an automatic gauging system.

All of Permian's/Earthstone's flare stacks, both currently installed and for future installation, are:

1) Appropriately sized and designed to ensure proper combustionefficiency
2) Equipped with an automatic ignitor or continuous pilot.
3) Anchored and located at least 100 feet from the well and storage tanks.

Permian's /Earthstone's field operations and HSE teams have implemented an AVO inspection schedule that adheres to the requirements of 19.15.27.8.E(5).

All of our operations and facilities are designed to minimize waste. We routinely employ the following methods and practices:

- Closed-loop systems
- Enclosed and properly sized tanks

- Vapor recovery units to maximize recovery of low-pressure gas streams and potential unauthorized emissions
- Low-emitting or electric engines whenever practical
- Combustors and flare stacks in the event of a malfunction or emergency
- Routine facility inspections to identify leaking components, functioning control devices, such as flares and combustors, and repair / replacement of malfunctioning components where applicable

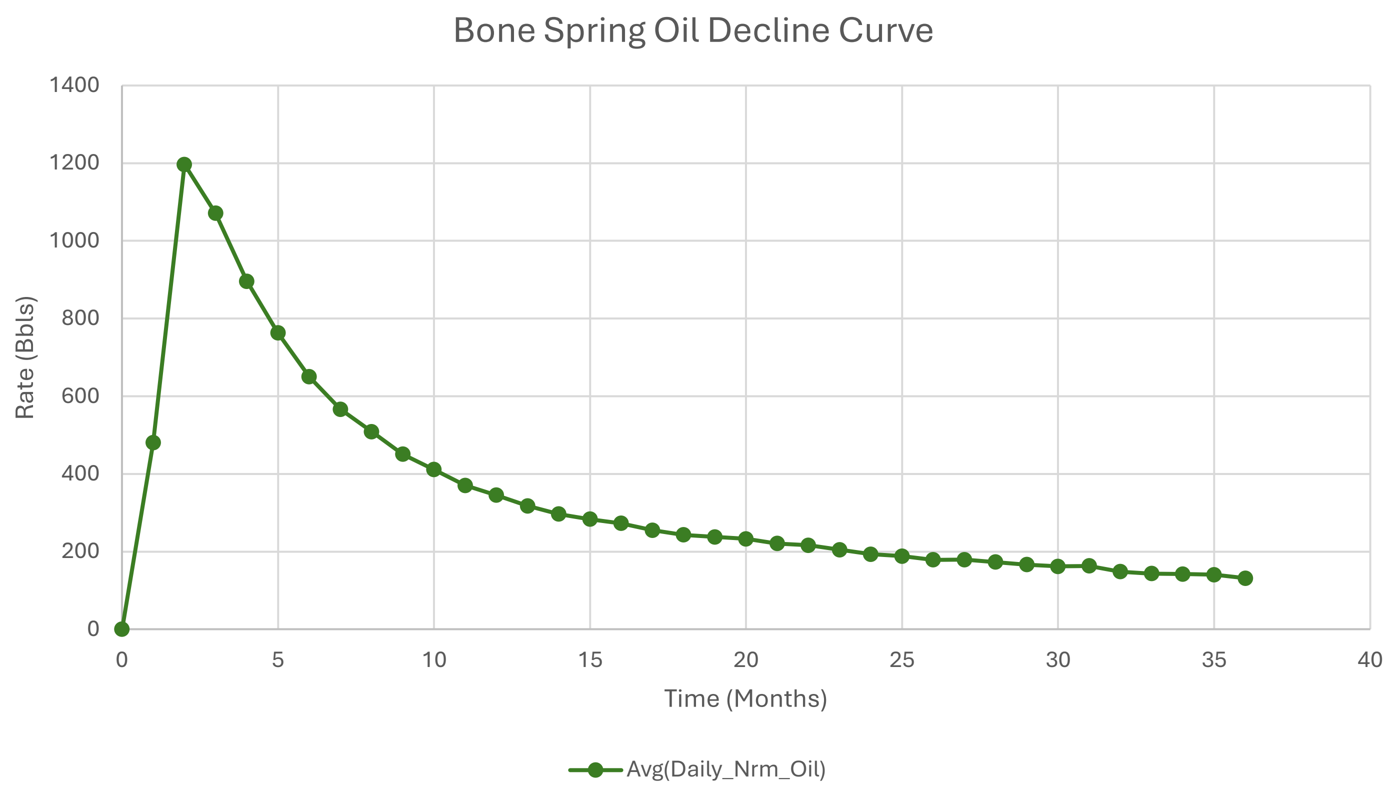
Measurement or estimation

Permian/Earthstone measures or estimates the volumes of natural gas vented, flared and/or beneficially used for all of our drilling, completing and producing wells. We utilize accepted industry standards and methodology which can be independently verified. Annual GOR testing is completed on our wells and will be submitted as required by the OCD. None of our equipment is designed to allow diversion around metering elements except during inspection, maintenance and repair operations.

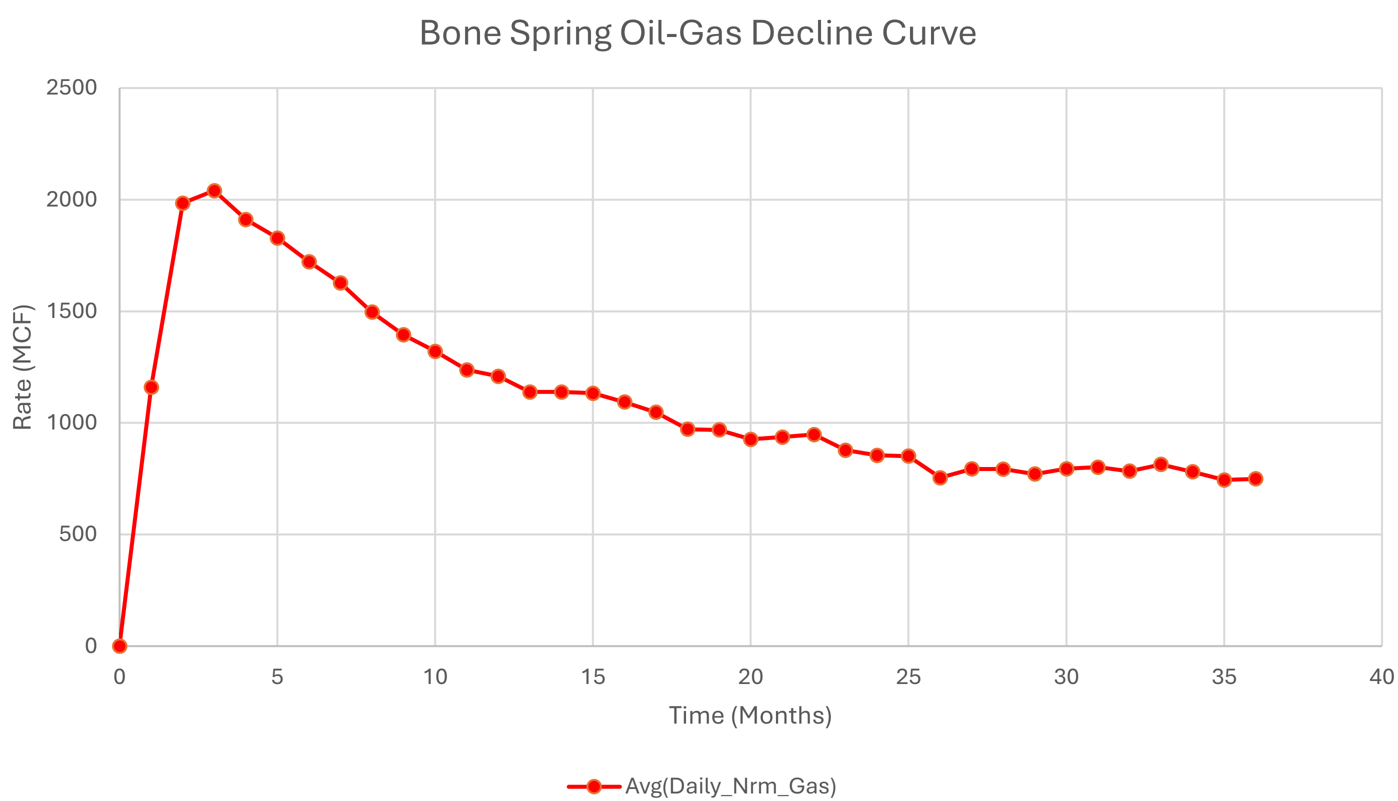
VIII. Best Management Practices:

Permian/Earthstone utilizes the following BMPs to minimize venting during active and planned maintenance activities:

- Use a closed-loop process wherever possible during planned maintenance activities, such as blowdowns, liquid removal, and work over operations.
- Employ low-emitting or electric engines for equipment, such as compressors
- Adhere to a strict preventative maintenance program which includes routine facility inspections, identification of component malfunctions, and repairing or replacing components such as hatches, seals, valves, etc. where applicable
- Utilize vapor recovery units (VRU's) to maximize recovery of volumes of low-pressure gas streams and potential unauthorized emissions
- Route low pressure gas and emissions streams to a combustion device to prevent venting where necessary



1. Represented curve is generic based on 3-Years available information for the Bone Spring formation and may not be representative of forecasted production or actual volumes.
2. Decline curves are based on an average 10,000ft lateral length. Multiple factors may influence production and decline curves, including but not limited to: lateral length and completion type.



1. Represented curve is generic based on 3-Years available information for the Bone Spring formation and may not be representative of forecasted production or actual volumes.
2. Decline curves are based on an average 10,000ft lateral length. Multiple factors may influence production and decline curves, including but not limited to: lateral length and completion type.