AFMSS

U.S. Department of the Interior
BUREAU OF LAND MANAGEMENT

Sundry Print Report

01/12/2026

Well Name: CO 34 27 FEDERAL COM

Well Location: T25S / R32E / SEC 3 / LOT 1 / 32.164947 / -103.655593

County or Parish/State: LEA / NM

Well Number: 637H

Type of Well: OIL WELL

Allottee or Tribe Name:

Lease Number: NMLC061936

Unit or CA Name:

Unit or CA Number:

US Well Number: 3002554287

Operator: CHEVRON USA INCORPORATED

Notice of Intent

Sundry ID: 2887363

Type of Submission: Notice of Intent

Type of Action: APD Change

Date Sundry Submitted: 12/17/2025

Time Sundry Submitted: 08:29

Date proposed operation will begin: 12/17/2025

Procedure Description: CHEVRON USA INC REQUESTS TO MAKE THE FOLLOWING CHANGES TO THE ORIGINAL APD FOR COTTON DRAW PAD 633: CHANGE TO PRODUCTION LINER FROM 5.5” 20# TO 5” 13# WILL BE KEPT FULL WHILE RUNNIING TO MITIGATE THE FULL EVACUATION COLLAPSE LOAD. REQUESTING APPROVAL OF THE 5.5” 17# CONTINGENCY CASING IN THE EVENT THE 5” 13# HAS CHALLENGES GETTING TO TD. PLEASE SEE ATTACHED NEW 9 PT AND CASING DESIGN

NOI Attachments

Procedure Description

CO_SH_2_20251217082856.pdf

CO_34_27_FEDERAL_COM__637H_9_PT_Plan_12Dec25__1__20251217082845.pdf

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Conditions of Approval

Additional

_CO_3_10_FED_AND_CO_34_27_FED_COM_Lea__CHEVRON_USA_INCORPORATED_45826_JS_20260106112050.pdf

CO_34_27_FEDERAL_COM_637H_COAs_20260106112050.pdf

_CO_3_10_FED_AND_CO_34_27_FED_COM_Lea__CHEVRON_USA_INCORPORATED_45826_JS_17__20260106112050.pdf

Operator

I certify that the foregoing is true and correct. 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. Electronic submission of Sundry Notices through this system satisfies regulations requiring a

Operator Electronic Signature: CINDY HERRERA-MURILLO **Signed on:** DEC 17, 2025 08:28 AM

Name: CHEVRON USA INCORPORATED

Title: Permitting Specialist

Street Address: 1616 W BENDER BLVD

City: HOBBS **State:** NM

Phone: (575) 263-0431

Email address: CHERRERAMURILLO@CHEVRON.COM

Field

Representative Name:

Street Address:

City: **State:** **Zip:**

Phone:

Email address:

BLM Point of Contact

BLM POC Name: CHRISTOPHER WALLS **BLM POC Title:** Petroleum Engineer

BLM POC Phone: 5752342234 **BLM POC Email Address:** CWALLS@BLM.GOV

Disposition: Approved **Disposition Date:** 01/08/2026

Signature: Chris Walls

Form 3160-5
(October 2024)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

FORM APPROVED
OMB No. 1004-0220
Expires: October 31, 2027

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 page 2*

5. Lease Serial No. NMLC061936

6. If Indian, Allottee or Tribe Name

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

1. Type of Well
☑ Oil Well ☐ Gas Well ☐ Other

8. Well Name and No. CO 34 27 FEDERAL COM/637H

2. Name of Operator CHEVRON USA INCORPORATED

9. API Well No. 3002554287

3a. Address PO BOX 1392, BAKERSFIELD, CA 93302

3b. Phone No. *(include area code)* (661) 633-4000

10. Field and Pool or Exploratory Area WC-025 G-08 S253216D/UPPER WOLFCAMP

4. Location of Well *(Footage, Sec., T.,R.,M., or Survey Description)*
SEC 3/T25S/R32E/NMP

11. Country or Parish, State LEA/NM

12. CHECK THE 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
	☐ Alter Casing	☐ Hydraulic Fracturing	☐ Reclamation	☐ Well Integrity
☐ Subsequent Report	☐ Casing Repair	☐ New Construction	☐ Recomplete	☐ Other
	☑ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
☐ Final Abandonment Notice	☐ 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 perfonned or provide the Bond No. on file with BLM/BIA. Required subsequent reports must 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 must be filed once testing has been completed. Final Abandonment Notices must be filed only after all requirements, including reclamation, have been completed and the operator has detennined that the site is ready for final inspection.)

CHEVRON USA INC REQUESTS TO MAKE THE FOLLOWING CHANGES TO THE ORIGINAL APD FOR COTTON DRAW PAD 633:
CHANGE TO PRODUCTION LINER FROM 5.5 20# TO 5 13# WILL BE KEPT FULL WHILE RUNNIING TO MITIGATE THE FULL EVACUATION COLLAPSE LOAD.
REQUESTING APPROVAL OF THE 5.5 17# CONTINGENCY CASING IN THE EVENT THE 5 13# HAS CHALLENGES GETTING TO TD.
PLEASE SEE ATTACHED NEW 9 PT AND CASING DESIGN

14. I hereby certify that the foregoing is true and correct. Name *(Printed/Typed)*
CINDY HERRERA-MURILLO / Ph: (575) 263-0431

Title Permitting Specialist

Signature (Electronic Submission)

Date 12/17/2025

THE SPACE FOR FEDERAL OR STATE OFICE USE

Approved by
CHRISTOPHER WALLS / Ph: (575) 234-2234 / Approved

Title Petroleum Engineer

Date 01/08/2026

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 CARLSBAD

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.

(Instructions on page 2)

GENERAL INSTRUCTIONS

This form is designed for submitting proposals to perform certain well operations and reports of such operations when completed as indicated on Federal and Indian lands pursuant to applicable Federal law and regulations. Any necessary special instructions concerning the use of this form and the number of copies to be submitted, particularly with regard to local area or regional procedures and practices, are either shown below, will be issued by or may be obtained from the local Federal office.

SPECIFIC INSTRUCTIONS

Item 4 - Locations on Federal or Indian land should be described in accordance with Federal requirements. Consult the local Federal office for specific instructions.

Item 13: Proposals to abandon a well and subsequent reports of abandonment should include such special information as is required by the local Federal office. In addition, such proposals and reports should include reasons for the abandonment; data on any former or present productive zones or other zones with present significant fluid contents not sealed off by cement or otherwise; depths (top and bottom) and method of placement of cement plugs; mud or other material placed below, between and above plugs; amount, size, method of parting of any casing, liner or tubing pulled and the depth to the top of any tubing left in the hole; method of closing top of well and date well site conditioned for final inspection looking for approval of the abandonment. If the proposal will involve **hydraulic fracturing operations**, you must comply with 43 CFR 3162.3-3, including providing information about the protection of usable water. Operators should provide the best available information about all formations containing water and their depths. This information could include data and interpretation of resistivity logs run on nearby wells. Information may also be obtained from state or tribal regulatory agencies and from local BLM offices.

NOTICES

The privacy Act of 1974 and the regulation in 43 CFR 2.48(d) provide that you be furnished the following information in connection with information required by this application.
AUTHORITY: 30 U.S.C. 181 et seq., 351 et seq., 25 U.S.C. 396; 43 CFR 3160.
PRINCIPAL PURPOSE: The information is used to: (1) Evaluate, when appropriate, approve applications, and report completion of subsequent well operations, on a Federal or Indian lease; and (2) document for administrative use, information for the management, disposal and use of National Resource lands and resources, such as: (a) evaluating the equipment and procedures to be used during a proposed subsequent well operation and reviewing the completed well operations for compliance with the approved plan; (b) requesting and granting approval to perform those actions covered by 43 CFR 3162.3-2, 3162.3-3, and 3162.3-4; (c) reporting the beginning or resumption of production, as required by 43 CFR 3162.4-1(c)and (d) analyzing future applications to drill or modify operations in light of data obtained and methods used.
ROUTINE USES: Information from the record and/or the record will be transferred to appropriate Federal, State, local or foreign agencies, when relevant to civil, criminal or regulatory investigations or prosecutions in connection with congressional inquiries or to consumer reporting agencies to facilitate collection of debts owed the Government.
EFFECT OF NOT PROVIDING THE INFORMATION: Filing of this notice and report and disclosure of the information is mandatory for those subsequent well operations specified in 43 CFR 3162.3-2, 3162.3-3, 3162.3-4.

The Paperwork Reduction Act of 1995 requires us to inform you that:
The BLM collects this information to evaluate proposed and/or completed subsequent well operations on Federal or Indian oil and gas leases.
Response to this request is mandatory.
The BLM would like you to know that you do not have to respond to this or any other Federal agency-sponsored information collection unless it displays a currently valid OMB control number.

BURDEN HOURS STATEMENT: Public reporting burden for this form is estimated to average 8 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect ofthis form to U.S. Department ofthe Interior, Bureau ofLand Management (1004-0137), Bureau Information Collection Clearance Officer (WO-630), 1849 C St., N.W., Mail Stop 401 LS, Washington, D.C. 20240

Additional Information

Location of Well

0. SHL: LOT 1 / 674 FNL / 487 FEL / TWSP: 25S / RANGE: 32E / SECTION: 3 / LAT: 32.164947 / LONG: -103.655593 (TVD: 0 feet, MD: 0 feet)
PPP: NESE / 2639 FNL / 750 FEL / TWSP: 24S / RANGE: 32E / SECTION: 27 / LAT: 32.188564 / LONG: -103.656406 (TVD: 12940 feet, MD: 18321 feet)
PPP: SESE / 25 FSL / 750 FEL / TWSP: 24S / RANGE: 32E / SECTION: 34 / LAT: 32.166867 / LONG: -103.656411 (TVD: 12940 feet, MD: 13321 feet)
BHL: NENE / 25 FNL / 750 FEL / TWSP: 24S / RANGE: 32E / SECTION: 27 / LAT: 32.19575 / LONG: -103.656404 (TVD: 12940 feet, MD: 23829 feet)

_CO 3 10 FED AND CO 34 27 FED COM_Lea__CHEVRON USA INCORPORATED_45826_JS

CO 3 10 FED AND CO 34 27 FED COM

13 3/8 surface csg in a 17 1/2 inch hole. **Design Factors** Surface

Segment	#/ft	Grade	Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	54.50	j 55	btc	14.60	2.03	0.93	1,072	6	1.48	3.52	58,424
"B"			btc				0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig: 1,443		Tail Cmt	does not	circ to sfc.	Totals:	1,072				58,424

Comparison of Proposed to Minimum Required Cement Volumes

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
17 1/2	0.6946	781	1140	745	53	10.00	1847	2M	1.56

Burst Frac Gradient(s) for Segment(s) A, B = , b All > 0.70, OK.

Site plat (pipe racks S or E) as per O.O.1.III.D.4.i. not found.

10 3/4 casing inside the 13 3/8 **Design Factors** Int 1

Segment	#/ft	Grade	Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	40.50	j 55	btc	3.17	0.54	0.4	4,893	1	0.62	0.86	198,167
"B"							0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig: 56					Totals:	4,893				198,167

The cement volume(s) are intended to achieve a top of 0 ft from surface or a 1072 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
12 1/4	0.1882	535	1110	974	14	11.50	5036	10M	0.25
D V Tool(s):							sum of sx	Σ CuFt	Σ%excess
t by stage % :		#VALUE!	#VALUE!				535	1110	14

Class 'C' tail cmt yld > 1.35

MASP is within 10% of 5000psig, need exrta equip?

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.64, b, c, d <0.70 a Problem!!

Keep Casing Full, Burst ok Chevron documentation attached, Does not meet CFO 25% excess on cement

7 5/8 casing inside the 10 3/4 **Design Factors** Int 2

Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	29.70	p 110	w441	1.61	1.41	0.95	11,922	1	1.46	2.30	354,083
"B"							0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig: -50					Totals:	11,922				354,083

The cement volume(s) are intended to achieve a top of 4693 ft from surface or a 200 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
9 5/8	0.1882	977	3055	1369	123	12.00	5685	10M	0.86

Class 'C' tail cmt yld > 1.35

MASP is within 10% of 5000psig, need exrta equip?

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.62, b, c, d <0.70 a

5 Liner w/top @ 11722 **Design Factors** Liner

Segment	#/ft	Grade	Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	13.00	p 110	w421	2.56	0.85	1.31	11,809	1	1.95	1.27	153,517
"B"			0.00				0				0
	w/8.4#/g mud, 30min Sfc Csg Test psig: 2,747					Totals:	11,809				153,517

The cement volume(s) are intended to achieve a top of 11722 ft from surface or a 200 overlap.

Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE	Min Dist Hole-Cplg
6 3/4	0.1122	1089	1655	1326	25	13.00			0.80

Class 'H' tail cmt yld > 1.20

Capitan Reef est top XXXX.

MASP is within 10% of 5000psig, need exrta equip?

Keep Casing full Does not meet CFO 25% excess on cement

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	CHEVRON USA INCORPORATED
WELL NAME & NO.:	CO 34 27 FEDERAL COM 637H
LOCATION:	Section 3, T.25 S., R.32 E., NMP
COUNTY:	Lea County, New Mexico

COA

H2S	◉ Yes	○ No	
Potash	◉ None	○ Secretary	○ R-111-P
Cave/Karst Potential	◉ Low	○ Medium	○ High
Cave/Karst Potential	○ Critical		
Variance	○ None	◉ Flex Hose	○ Other
Wellhead	○ Conventional	◉ Multibowl	○ Both
Wellhead Variance	○ Diverter		
Other	☐ 4 String	☐ Capitan Reef	☐ WIPP
Other	☑ Fluid Filled	☐ Pilot Hole	☐ Open Annulus
Cementing	☐ Contingency Cement Squeeze	☐ EchoMeter	☐ Primary Cement Squeeze
Special Requirements	☐ Water Disposal	☑ COM	☐ Unit
Special Requirements	☐ Batch Sundry		
Special Requirements Variance	☑ Break Testing	☑ Offline Cementing	☐ Casing Clearance

A. HYDROGEN SULFIDE

A Hydrogen Sulfide (H2S) Drilling Plan shall be activated AT SPUD. As a result, the Hydrogen Sulfide area must meet 43 CFR part 3170 requirements, which includes equipment and personnel/public protection items. If Hydrogen Sulfide is encountered, please provide measured values and formations to the BLM.

B. CASING

Primary Casing Design:

1. The **13-3/8** inch surface casing shall be set at approximately **1021 feet** (a minimum of **25 feet (Lea County)** into the Rustler Anhydrite, above the salt, and below usable fresh water) and cemented to the surface. The surface hole shall be **17.5** inch in diameter.

    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 will be a minimum of **8 hours** or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement)
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.

Operator is approved to use contingency cementing for the Intermediate and Production section. Operator shall notify the BLM before proceeding with contingency operation.

2. The minimum required fill of cement behind the **10-3/4** inch intermediate casing is:

    - Cement to surface. If cement does not circulate see B.1.a, c-d above.
      Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.
      Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.

    Intermediate casing must be kept fluid filled to meet BLM minimum collapse requirement.

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

    - Cement should tie-back at least **200 feet** into previous casing string. Operator shall provide method of verification.
      Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.

4. The minimum required fill of cement behind the **5** inch production liner is:

    - Cement should tie-back **100 feet** into the previous casing. Operator shall provide method of verification.
      Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.
      Cement excess is less than 25%, more cement is required if washout occurs. Adjust cement volume and excess based on a fluid caliper or similar method that reflects the as-drilled size of the wellbore.

Production liner must be kept fluid filled to meet BLM minimum collapse requirement.

Contingency Production liner:

5. The minimum required fill of cement behind the **5-1/2** inch production liner is:

    - Cement should tie-back **100 feet** into the previous casing. Operator shall provide method of verification.
    Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.

C. PRESSURE CONTROL

1. Variance approved to use flex line from BOP to choke manifold. Manufacturer's specification to be readily available. No external damage to flex line. Flex line to be installed as straight as possible (no hard bends).'

2. Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the **13-3/8** inch surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be **5000 (5M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 3500 (70% Working Pressure) psi.**

    a. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    b. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    c. Manufacturer representative shall install the test plug for the initial BOP test.
    d. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
    e. Whenever any seal subject to test pressure is broken, all the tests in **43 CFR 3172.6(b)(9)** must be followed

D. SPECIAL REQUIREMENT (S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Santa Fe Office, 301 Dinosaur Trail Santa Fe, New Mexico 87508, at least 90 days before the anticipated date of first production from a well subject to a spacing order issued by the New Mexico Oil Conservation Division. The Communitization Agreement will include the signatures of all working interest owners in all Federal and Indian leases subject to the Communitization Agreement (i.e., operating rights owners and lessees of record), or certification that the operator has obtained the written signatures of all such owners and will make those signatures available to the BLM immediately upon request.

- The operator will submit an as-drilled survey well plat of the well completion, but are not limited to, those specified in 43 CFR 3170.
- If the operator does not comply with this condition of approval, the BLM may take enforcement actions that include, but are not limited to, those specified in 43 CFR 3163.1.
- In addition, the well sign shall include the surface and bottom hole lease numbers. <u>When the Communitization Agreement number is known, it shall also be on the sign.</u>

<u>(Note: For a minimum 5M BOPE or less (Utilizing a 10M BOPE system)</u>
<u>BOPE Break Testing Variance</u>

- BOPE Break Testing is ONLY permitted for 5M BOPE or less. **(Annular preventer must be tested to a minimum of 70% of BOPE working pressure and shall be higher than the MASP)**
- BOPE Break Testing is NOT permitted to drilling the production hole section.
- Variance only pertains to the intermediate hole-sections and no deeper than the Bone Springs formation.
- While in transfer between wells, the BOPE shall be secured by the hydraulic carrier or cradle.
- Any well control event while drilling require notification to the BLM Petroleum Engineer **(575-706-2779)** prior to the commencement of any BOPE Break Testing operations.
- A full BOPE test is required prior to drilling the first deep intermediate hole section. If any subsequent hole interval is deeper than the first, a full BOPE test will be required. (200’ TVD tolerance between intermediate shoes is allowable).
- The BLM is to be contacted (575-689-5981 Lea County) 4 hours prior to BOPE tests.
- As a minimum, a full BOPE test shall be performed at 21-day intervals.
- In the event any repairs or replacement of the BOPE is required, the BOPE shall test as per 43 CFR 3170.

Offline Cementing
Contact the BLM prior to the commencement of any offline cementing procedure.

GENERAL 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)

☒ Eddy County
EMAIL or call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220,

BLM_NM_CFO_DrillingNotifications@BLM.GOV
(575) 361-2822

☒ Lea County
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240,
(575) 689-5981

1. 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.
   a. In the event the operator has proposed to drill multiple wells utilizing a skid/walking rig. Operator shall secure the wellbore on the current well, after installing and testing the wellhead, by installing a blind flange of like pressure rating to the wellhead and a pressure gauge that can be monitored while drilling is performed on the other well(s).
   b. When the operator proposes to set surface casing with Spudder Rig
      i. Notify the BLM when moving in and removing the Spudder Rig.
      ii. Notify the BLM when moving in the 2nd Rig. Rig to be moved in within 90 days of notification that Spudder Rig has left the location.
      iii. BOP/BOPE test to be conducted per **43 CFR 3172** as soon as 2nd Rig is rigged up on well.
2. 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 are located, this does not include the dog house or stairway area.
3. For intervals in which cement to surface is required, cement to surface should be verified with a visual check and density or pH check to differentiate cement from spacer and drilling mud. The results should be documented in the driller's log and daily reports.

A. CASING

1. 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.

2. Wait on cement (WOC) for Potash Areas: 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 for all cement blends of both lead and tail cement, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.
3. 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. The casing integrity test can be done (prior to the cement setting up) immediately after bumping the plug.
4. 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.
5. No pea gravel permitted for remedial or fall back remedial without prior authorization from the BLM engineer.
6. On that portion of any well approved for a 5M BOPE system or greater, a pressure integrity test of each casing shoe shall be performed. Formation at the shoe shall be tested to a minimum of the mud weight equivalent anticipated to control the formation pressure to the next casing depth or at total depth of the well. This test shall be performed before drilling more than 20 feet of new hole.
7. 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.
8. Whenever a casing string is cemented in the R-111-Q potash area, the NMOCD requirements shall be followed.

B. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in **43 CFR 3172**.

2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: The flex line must meet the requirements of API 16C. 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.
3. 5M or higher 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.
4. If the operator has proposed a multi-bowl wellhead assembly in the APD. The following requirements must be met:
    i. Wellhead shall be installed by manufacturer's representatives, submit documentation with subsequent sundry.
    ii. If the welding is performed by a third party, the manufacturer's representative shall monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
    iii. Manufacturer representative shall install the test plug for the initial BOP test.
    iv. Whenever any seal subject to test pressure is broken, all the tests in 43 CFR 3172.6(b)(9) must be followed.
    v. If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head shall be cut off, cementing operations performed and another wellhead installed.
5. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.
    i. 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 cement), 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).

ii. In potash areas, 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. For all casing strings, casing cut-off and BOP installation can be initiated at twelve hours after bumping the cement plug. The BOPE test can be initiated after bumping the cement plug with the casing valve open. (only applies to single stage cement jobs, prior to the cement setting up.)

iii. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer and can be initiated immediately with the casing valve open. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to **43 CFR 3172** with the pressure not to exceed 70% of the burst rating for the casing. Any test against the casing must meet the WOC time for 8 hours or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

iv. 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.

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

vi. 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.

vii. 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.

viii. 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 **43 CFR 3172**.

C. 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.

D. 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.

JS 1/6/2026

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CO 3 10 FED AND CO 34 27 FED COM

13 3/8		surface csg in a	17 1/2	inch hole.		Design Factors					Surface	
Segment	#/ft	Grade		Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	54.50		j 55	btc	14.60	2.03	0.93	1,072	6	1.48	3.52	58,424
"B"				btc				0				0
		w/8.4#/g mud, 30min Sfc Csg Test psig:	1,443	Tail Cmt	does not	circ to sfc.	Totals:	1,072				58,424
Comparison of Proposed to Minimum Required Cement Volumes												
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
17 1/2	0.6946	781	1140	745	53	10.00	1847	2M				1.56

Burst Frac Gradient(s) for Segment(s) A, B = , b All > 0.70, OK.

Site plat (pipe racks S or E) as per O.O.1.III.D.4.i. not found.

10 3/4		casing inside the	13 3/8	_		Design Factors					Int 1	
Segment	#/ft	Grade		Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	40.50		j 55	btc	3.17	0.54	0.4	4,893	1	0.62	0.86	198,167
"B"								0				0
		w/8.4#/g mud, 30min Sfc Csg Test psig:	56				Totals:	4,893				198,167
		The cement volume(s) are intended to achieve a top of			0	ft from	surface or a	1072				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
12 1/4	0.1882	535	1110	974	14	11.50	5036	10M				0.25
D V Tool(s):							sum of sx	Σ CuFt				Σ%excess
t by stage % :		#VALUE!	#VALUE!				535	1110				14

Class 'C' tail cmt yld > 1.35

MASP is within 10% of 5000psig, need exrta equip?

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.64, b, c, d <0.70 a Problem!!

Keep Casing Full, Burst ok Chevron documentation attached, Does not meet CFO 25% excess on cement

7 5/8		casing inside the	10 3/4	_		Design Factors					Int 2	
Segment	#/ft	Grade		Coupling	Joint	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	29.70		p 110	w441	1.61	1.41	0.95	11,922	1	1.46	2.30	354,083
"B"								0				0
		w/8.4#/g mud, 30min Sfc Csg Test psig:	-50				Totals:	11,922				354,083
		The cement volume(s) are intended to achieve a top of			4693	ft from	surface or a	200				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
9 5/8	0.1882	977	3055	1369	123	12.00	5685	10M				0.86

Class 'C' tail cmt yld > 1.35 MASP is within 10% of 5000psig, need exrta equip?

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.62, b, c, d <0.70 a

5 1/2		Liner w/top @	11722	_		Design Factors					Liner	
Segment	#/ft	Grade		Coupling	Body	Collapse	Burst	Length	B@s	a-B	a-C	Weight
"A"	17.00		p 110	w451	3.02	1.46	1.7	11,809	2	2.53	2.16	200,753
"B"				0.00				0				0
		w/8.4#/g mud, 30min Sfc Csg Test psig:	2,747				Totals:	11,809				200,753
		The cement volume(s) are intended to achieve a top of			11722	ft from	surface or a	200				overlap.
Hole Size	Annular Volume	1 Stage Cmt Sx	1 Stage CuFt Cmt	Min Cu Ft	1 Stage % Excess	Drilling Mud Wt	Calc MASP	Req'd BOPE				Min Dist Hole-Cplg
6 3/4	0.0835	1089	1655	988	68	13.00						0.43

Class 'H' tail cmt yld > 1.20 Capitan Reef est top XXXX. MASP is within 10% of 5000psig, need exrta equip?

Cover Page

Cotton Draw Casing Design

Scope and Type Well Design Criteria

Scope and Type Well Design Criteria	
Area(s)	Cotton Draw
Formation(s)	All formation targets
Casing Design(s)	4-String Slimhole 2.0 Type Well
Sour Service	No
Type Well Design Criteria	Deepest WCA in Cotton Draw - applicable to all shallower wells in South Lea County Mid-case (expected) pore and frac pressures based on 2025 Cotton Draw Basis of Design Document 3-mile lateral with 3,800' MD step-out

DrillPlan

Table of Contents

DrillPlan

1 Load Case Assumptions

1.1 Surface Casing

Surface Casing - Drilling Load Case Assumptions

Drilling Load Case Assumptions		
Surface Casing - 13-3/8", 54.5 lb/ft, J55, BTC, MCBU		
	Internal Pressure Profile	**External Pressure Profile**
Burst	1) Pressure test to 1500 psi w/ 8.4 ppg MW 2) MASP of 727 psi connected linearly to frac gradient[1] at shoe.	1) Pore Pressure[1]
Collapse	1) Fixed mud drop at 2000' w/ 10.6 ppg max MW for next hole section. 2) Initial Conditions – Cementing w/ 8.7 ppg displacement fluid density.	1) 10.60 lbm/gal Max MW at TD 2) 8.70 lbm/gal at TD, Spacer, Cement
Axial	1) Casing weight, 8.7 ppg displacement fluid + 100 kips Overpull[3]	1) 8.70 lbm/gal at TD, Spacer, Cement

1.2 Intermediate 1 Casing

Intermediate 1 Casing - Drilling Load Case Assumptions

Drilling Load Case Assumptions		
Casing - 10.75", 40.5#, J55, BTC, MCBU		
	Internal Pressure Profile	**External Pressure Profile**
Burst	1) Pressure test to 2000 psi w/ 8.34 ppg MW 2) MASP of 1388psi connected linearly to frac gradient[1] at shoe.	1) Pore Pressure[1]
Collapse	1) Fixed mud drop at 2000' w/ 11.0 ppg max MW for next hole section. 2) Initial Conditions – Cementing w/ 8.4 ppg displacement fluid density.	1) 11.00 lbm/gal Max MW at TD 2) 10.00 lbm/gal at TD, Spacer, Cement
Axial	1) Casing weight, 8.4 ppg displacement fluid + 100 kips Overpull[3]	1) 10.00 lbm/gal at TD, Spacer, Cement

1.3 Production (Intermediate 2) Casing

Production (Intermediate 2) Casing - Drilling and Production Load Case Assumptions

Drilling and Production Load Case Assumptions		
Production Casing - 7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU		
	Internal Pressure Profile	**External Pressure Profile**
Burst	1) Pressure test to 9700 psi w/ 8.5 ppg MW (**Completion Operations pressure test**) 2) Frac Screenout Pressure 9400 psi w/ 9.95 ppg proppant-laden fluid density[2]. (**Operational limit during frac execution**) 3) Pressure test to 4000 psi w/ 8.4 ppg fluid density (Liner Top packer test) 4) Tubing leak w/ packer at 11,500' TVD and 8.7 ppg packer fluid density. 5) MASP of 3108 psi connected linearly to frac gradient[1] at shoe.	1) Pore Pressure[1]
Collapse	1) Evacuated Collapse, 0 psi 2) Fixed mud drop at 2000' w/ 8.3ppg min MW for next hole section. 3) Initial Conditions – Cementing w/ 8.34 ppg displacement fluid density.	1) 11.50 lbm/gal Max MW at TD 2) 11.50 lbm/gal Max MW at TD 3) 8.70 lbm/gal at TD, Spacer, Cement
Axial	1) Casing weight,8.7 ppg displacement fluid + 100 kips Overpull[3]	1) 8.70 lbm/gal at TD, Spacer, Cement

1.4 Production Liner

Production Liner - Production Load Case Assumptions

Production Load Case Assumptions		
Production Liner - 5-inch, 13 lb/ft, P110-ICY, W421, MCBU		
	Internal Pressure Profile	**External Pressure Profile**
Burst	1) Pressure test to 9700 psi w/ 8.5 ppg MW (**Completion Operations pressure test**) 2) Frac Screenout Pressure 9400 psi w/ 9.5 ppg proppant-laden fluid density[2]. (**Operational limit during frac execution**) 3) Tubing leak w/ packer at 11,500' TVD and 8.7 ppg packer fluid density.	1) Pore Pressure[1]
Collapse	1) Evacuated Collapse, 0 psi 2) Initial Conditions – Cementing w/ 8.7 ppg displacement fluid density.	1) 13.00 lbm/gal Max MW at TD 2) 10.50 lbm/gal at TD, Spacer, Cement
Axial	1) Casing weight, 8.7 ppg displacement fluid + 100 kips Overpull[3]	1) 10.50 lbm/gal at TD, Spacer, Cement

[1]The mid-case (expected) pore and frac pressures are used and follow recommended gradients based on TOC

[2]Consideration is given to area specific produced water densities and maximum sand concentrations (details in Casing Pressure Test Plan section)

[3]Standard overpull is typically 100K but will be dictated by rig capacity and safety factors

Note:

- Full list of evaluated load cases can be found in Section 3.01 - Material and Connection Specifications and Load Case Evaluation Results
- Alternative load cases may need to be evaluated to establish surface pressure limitations based on well-specific conditions, equipment, and/or operational practices, e.g., casing collapse during planned or remedial top jobs, max differential across liner hanger PBR, annular pressure buildup, etc.

2 Maximum Anticipated Surface Pressure

Tubular	Tubular Type	Section	Definition	MASP (psi)	MAWP (psi)
13-3/8", 54.5 lb/ft, J55, BTC, MCBU	SurfaceCasing	12.25 in	Max openhole pore pressure with Chevron HC/mud ratios	765.44	771.71
10.75", 40.5#, J55, BTC, MCBU	Casing	9.875 in	Max openhole pore pressure with Chevron HC/mud ratios	1876.78	1883.05
7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	ProductionCasing	6.75 in	Max openhole pore pressure with Chevron HC/mud ratios	4971.26	4977.53
7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	ProductionCasing	Production	Shut-in Tubing Pressure	–	7088.81
5-inch, 13 lb/ft, P110-ICY, W421, MCBU	ProductionLiner	Production	Shut-in Tubing Pressure	–	7088.81

HC gradient - BLM basis of 0.22 psi/ft for and Young-Nagy gas gradient for the production hole section

3 Casing Design

3.1 Material and Connection Specifications

Section	17.5 in	12.25 in	9.875 in	6.75 in
Description	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	10.75", 40.5#, J55, BTC, MCBU	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	5-inch, 13 lb/ft, P110-ICY, W421, MCBU
Casing Type	Surface Casing	Casing	Production Casing	Production Liner
From (ft)	28.50	28.50	28.50	11465.17
To (ft)	1002.34	4811.17	11665.17	23418.67
Weight (lbm/ft)	54.50	40.50	29.70	13.00
Grade	J55	J55	P110ICY	P110ICY
Connection	BTC	BTC	W441	W421
BTC Torque	Triangle Apex	Unknown	Unknown	Unknown
Min. MUT (kft.lbf)			22.00	13.00
Opt. MUT (kft.lbf)			23.00	14.00
Max. MUT (kft.lbf)			26.00	15.00
Operating Torque (kft. lbf)			33.00	
Nominal OD (in)	13.375	10.750	7.625	5.000
Nominal ID (in)	12.615	10.050	6.875	4.494
Drift (in)	12.459	9.894	6.750	4.369
Coupling OD (in)	14.375	11.750	7.900	5.150
Body Burst Rating (psi)	2730.00	3130.00	11070.00	11070.00
Body Collapse Rating (psi)	1130.00	1580.00	7360.00	7200.00
Body Tension Rating (lbf)	853000.00	629000.00	1068000.00	472000.00
Body Compression Rating (lbf)	853000.00	629000.00	1068000.00	
Connection Burst Rating (psi)	2730.00	3130.00	11070.00	11070.00
Connection Collapse Rating (psi)	1130.00	1580.00	7360.00	7200.00
Connection Tension Rating (lbf)	909000.00	700000.00	801000.00	378000.00
Connection Compression Rating (lbf)	909000.00	628000.00	801000.00	378000.00

Note: Any casing grade or connection with higher performance ratings than components used for this analysis may be utilized. Ensure casing connection operating torque limit is sufficient for casing rotation and meets BLM clearance requirement (0.422 inches on all sides in the hole/casing annulus), if applicable.

Production Liner Note:

DrillPlan

5" 13 lb/ft P110-IC required to be kept full while running in hole. It can NOT be floated as it does not pass the full evacuation load case.

3.2 Load Case Evaluation Results

Casing Design Factors

String Type	Burst	Collapse	Tension	Compression	Von Mises	Connection Envelope (VME)
Surface Casing						
String Body	1.100	1.000	1.300	1.300	1.100	N/A
Non-API Connection	1.100	1.000	1.300	1.300	N/A	1.000
API Connection	1.100	1.000	1.600	1.600	N/A	1.000
Casing/Liner/Tieback						
String Body	1.100	1.000	1.300	1.300	1.100	N/A
Non-API Connection	1.100	1.000	1.300	1.300	N/A	1.000
API Connection	1.100	1.000	1.600	1.600	N/A	1.000
Production Casing/Liner/Tieback						
String Body	1.100	1.000	1.300	1.300	1.100	N/A
Non-API Connection	1.100	1.000	1.300	1.300	N/A	1.000
API Connection	1.100	1.000	1.600	1.600	N/A	1.000

Casing Design Results Summary

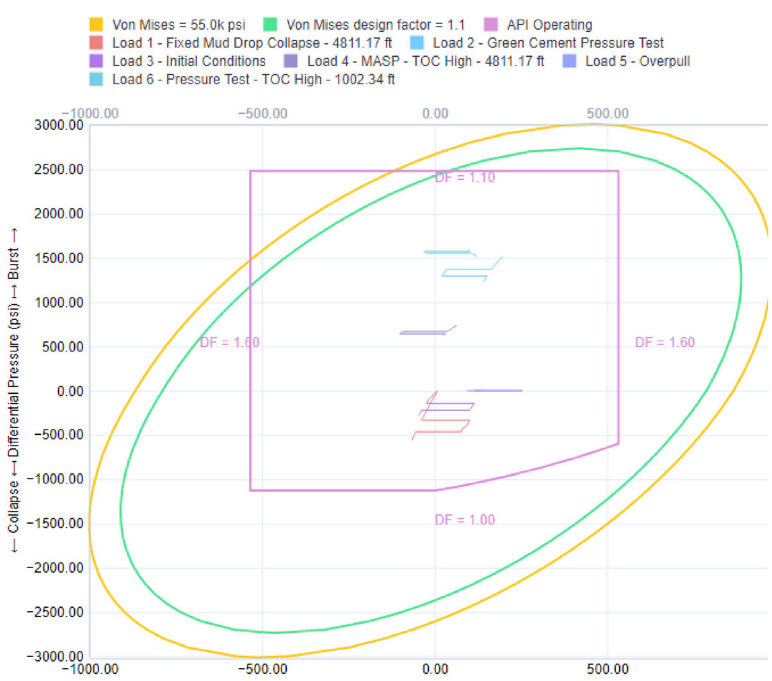
Section (Type)	String	Burst	Collapse	Tension	Compression	Von Mises	Buckling (deg/100ft)	Connection Envelope (VME)
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	1.715	2.053	2.803	4.426	1.693	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	1.150	1.016	1.931	C 4.541	1.230	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	1.103	1.039	C 1.623	C 3.150	1.167	3.000	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	1.219	1.007	C 2.381	C 2.357	1.331	8.100	N/A

Casing Design Results Detailed

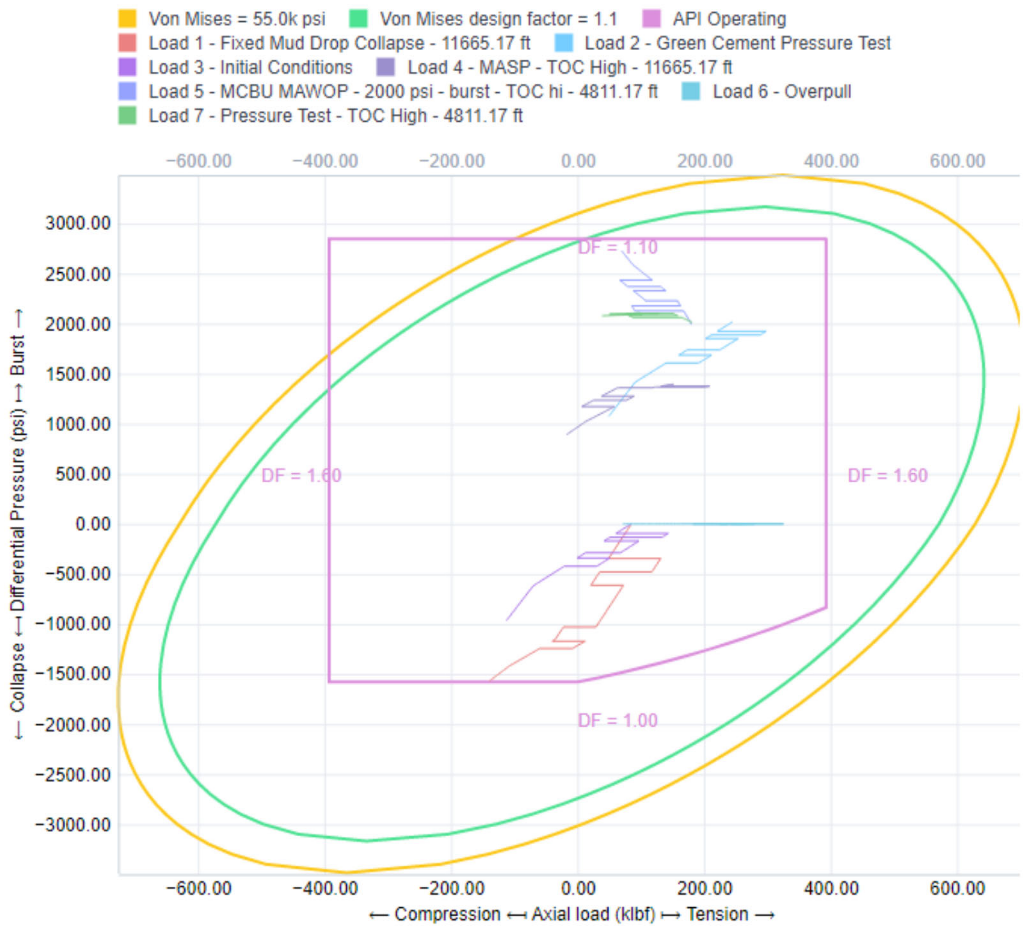
Section (Type)	String	Load Case	Burst	Collapse	Tension	Compression	Von Mises	Buckling (deg/100ft)	Connection Envelope (VME)
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	Fixed Mud Drop Collapse - 4811.17 ft		2.053	131.772	4.426	4.296	3.000	N/A
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	MASP - TOC High - 4811.17 ft	3.730		4.795		3.251	3.000	N/A
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	Pressure Test - TOC High - 1002.34 ft	1.715		3.490		1.693	3.000	N/A

17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	Green Cement Pressure Test	1.806		2.803		2.036	3.000	N/A
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	Overpull			3.349		3.295	3.000	N/A
17.5'' (Surface Casing)	13-3/8", 54.5 lb/ft, J55, BTC, MCBU	Initial Conditions		4.123	111.484	4.854	5.549	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	Fixed Mud Drop Collapse - 11665.17 ft		1.016	4.783	C 4.541	2.227	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	MASP - TOC High - 11665.17 ft	2.242		2.935	C 38.308	2.415	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	MCBU MAWOP - 2000 psi - burst - TOC hi - 4811.17 ft	1.150		2.516		1.230	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	Pressure Test - TOC High - 4811.17 ft	1.486		2.547		1.587	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	Green Cement Pressure Test	1.555		2.073		1.716	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	Overpull			1.931		1.909	3.000	N/A
12.25'' (Casing)	10.75", 40.5#, J55, BTC, MCBU	Initial Conditions		1.657	4.388	C 5.631	3.654	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	MASP - TOC High - 23418.67 ft	2.815		C 2.574	C 9.907	2.985	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	MCBU MAWOP - 2000 psi - collapse - 11665.17 ft		1.507	C 4.545	C 3.727	2.351	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Pressure Test - TOC High - 11665.17 ft	2.681		C 2.427	C 9.517	2.712	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Pressure Test - TOC High - 23418.67 ft	1.106		C 1.748		1.167	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Green Cement Pressure Test	2.747		C 2.068		2.577	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Overpull			C 1.862		2.469	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Initial Conditions		3.566	C 3.372	C 5.676	4.365	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Evacuated Collapse - 23418.67 ft		1.039	C 3.460	C 3.150	1.618	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Frac job - TOC High - 23418.67 ft	1.103		C 1.623		1.184	3.000	N/A

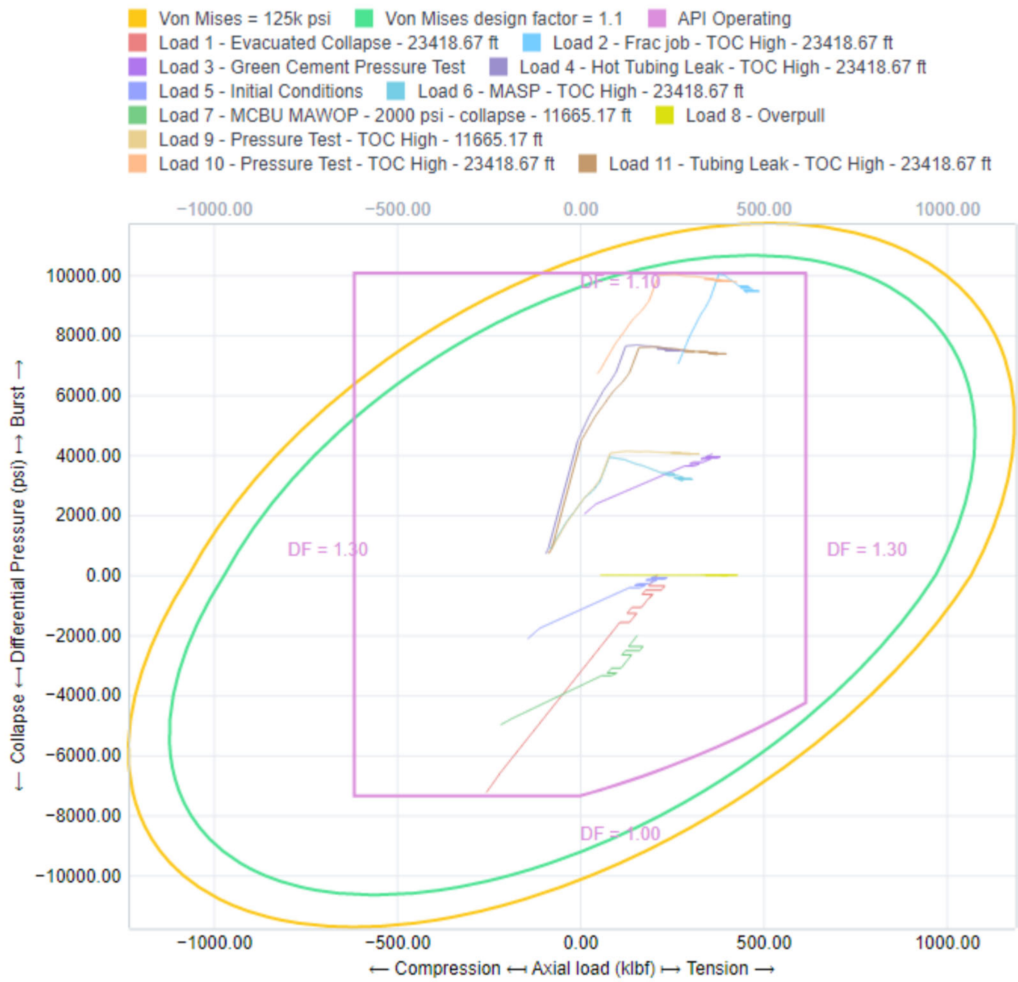
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Hot Tubing Leak - TOC High - 23418.67 ft	1.442		C 2.502	C 8.691	1.511	3.000	N/A
9.875'' (Production Casing)	7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU	Tubing Leak - TOC High - 23418.67 ft	1.455		C 1.981	C 9.479	1.538	3.000	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Evacuated Collapse: Int = FW @ 9000' TVD w/ Atm Pressure to Surface / Ext = Max MW		1.007		C 3.043	1.564	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Pressure Test - TOC High - 23418.67 ft	1.254		C 6.028		1.346	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Overpull			C 3.110		3.214	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Initial Conditions		4.373		C 4.218	6.351	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Frac job - TOC High - 23418.67 ft	1.219		C 2.381		1.344	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Hot Tubing Leak - TOC High - 23418.67 ft	1.710		C 12.237	C 4.814	1.828	8.100	N/A
6.75'' (Production Liner)	5-inch, 13 lb/ft, P110-ICY, W421, MCBU	Tubing Leak - TOC High - 23418.67 ft	1.713		C 10.760	C 4.814	1.838	8.100	N/A



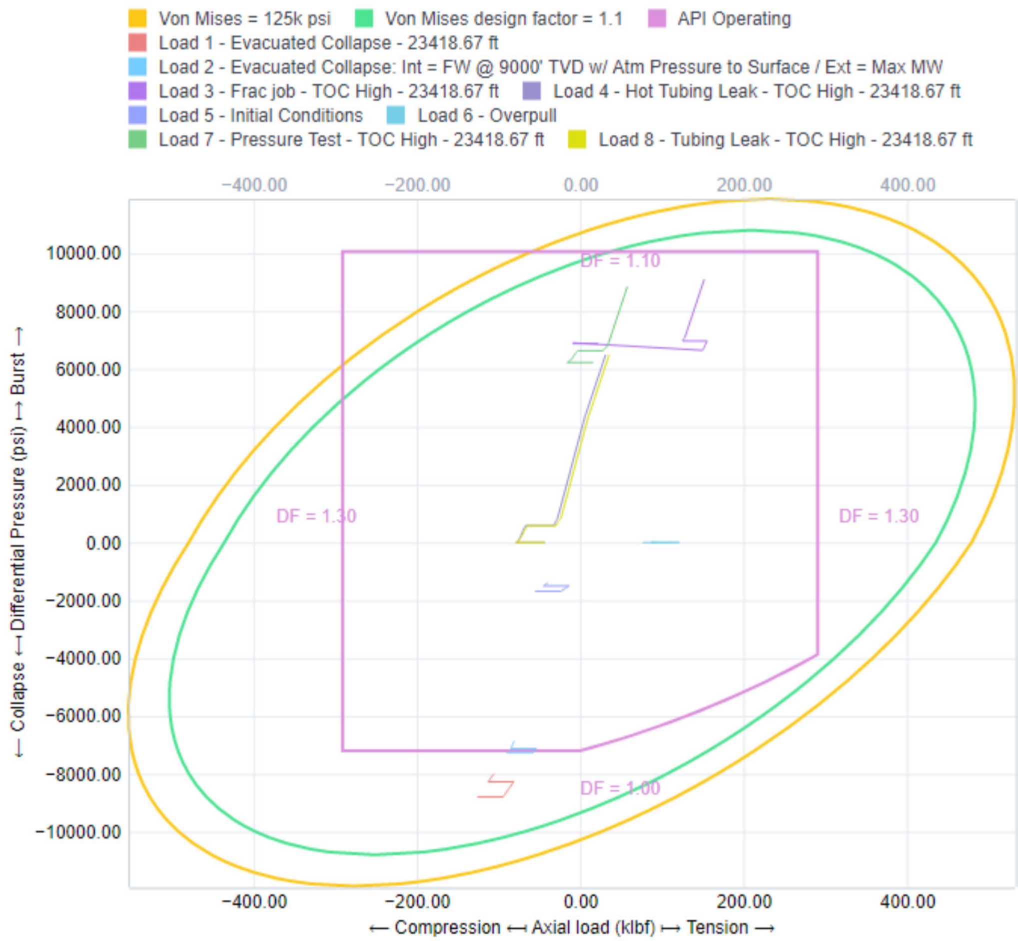
CASING TRIAXIAL: 13-3/8", 54.5 lb/ft, J55, BTC, MCBU (28.5 – 1002.34 ft)



CASING TRIAXIAL: 10.75", 40.5#, J55, BTC, MCBU (28.5 – 4811.17 ft)



CASING TRIAXIAL: 7-5/8-inch, 29.7 lb/ft, P110-ICY, W441, MCBU (28.5 – 11665.17 ft)



CASING TRIAXIAL: 5-inch, 13 lb/ft, P110-ICY, W421, MCBU (11465.17 – 23418.67 ft)

DrillPlan

4 PPFG/Temp

Pore pressure (MD)

MD (ft)	TVD (ft)	PRESSURE (psi)	EMW (lbm/gal)
28.50	28.50	0.00	0.00
793.47	793.14	291.28	7.07
1128.42	1125.70	404.54	6.92
3193.43	3179.26	1329.35	8.05
4702.49	4688.32	2005.41	8.23
4734.88	4720.71	2019.21	8.23
5610.76	5596.59	2421.48	8.33
6957.60	6943.43	3002.20	8.32
8608.26	8594.09	3803.40	8.52
8723.24	8709.07	4670.35	10.32
9123.00	9108.83	5168.77	10.92
9705.71	9691.54	5700.51	11.32
9958.03	9943.86	6003.89	11.62
10245.34	10231.17	6390.03	12.02
10793.62	10779.45	7068.40	12.62
11530.56	11516.39	8209.96	13.72
11991.07	11975.04	8723.30	14.02
12173.84	12144.50	8972.92	14.22
23418.67	12517.94	9247.33	14.22

Fracture pressure (MD)

MD (ft)	TVD (ft)	PRESSURE (psi)	EMW (lbm/gal)
28.50	28.50	0.00	0.00
793.47	793.14	844.30	20.49
1128.42	1125.70	1070.84	18.31
3193.43	3179.26	2991.05	18.11
4702.49	4688.32	3546.15	14.56
4734.88	4720.71	2905.69	11.85
5610.76	5596.59	3209.19	11.04
6957.60	6943.43	4051.16	11.23
8608.26	8594.09	5682.73	12.73
8723.24	8709.07	6030.65	13.33
9123.00	9108.83	6449.11	13.63
9705.71	9691.54	6759.89	13.43
9958.03	9943.86	7349.59	14.23

DrillPlan

10245.34	10231.17	7135.53	13.43
10793.62	10779.45	8358.67	14.93
11530.56	11516.39	9048.93	15.13
11991.07	11975.04	9657.94	15.53
12173.84	12144.50	10742.23	17.03
23418.67	12517.94	11074.00	17.03

Temperature

TVD (ft)	TEMPERATURE (degF)	GRADIENT (degF/(100 ft))
28.50	90.00	
29.50	90.00	
12600.00	195.00	0.84

Chevron
CO 34 27 FEDERAL COM 637H
Lea County, NM

Pad Summary: CO Pad 633

The table below lists all the wells for the given pad and their respective name and TVD's (ft) for their production target intervals:

Well Name(s)	Target TVD	Formation Desc.
CO 34 27 FEDERAL COM 633H	12,485	Wolfcamp A
CO 3 10 FEDERAL 634H	12,385	Wolfcamp A
CO 34 27 FEDERAL COM 635H	12,485	Wolfcamp A
CO 3 10 FEDERAL 636H	12,485	Wolfcamp A
CO 34 27 FEDERAL COM 637H	12,485	Wolfcamp A
CO 3 10 FEDERAL 638H	12,485	Wolfcamp A

1. **GEOLOGICAL TOPS**
Elevation: As seen in C-102

The estimated tops of important geologic markers are as follows:

FORMATION	LITHOLOGIES	TVD	MD	Producing Formation?
Rustler (RSLR)	Sandstone	887	888	No
Saldo (SLDO)	Anhydrite/Salt	1,213	1,219	No
Castile (CSTL)	Anhydrite/Salt	3,272	3,330	No
Lamar (LMAR)	Limestone/Shale	4,816	4,913	No
Bell Canyon (BEL)	Sandstone/Limestone	4,860	4,958	No
Cherry Canyon (CHR)	Sandstone/Siltstone	5,709	5,828	No
Brushy Canyon (BCN)	Sandstone/Limestone	7,093	7,233	No
Bone Spring (BSL)	Shale/Siltstone	8,736	8,876	No
Upper Avalon (AVU)	Shale	8,852	8,992	No
Lower Avalon (AVL)	Shale	9,218	9,358	No
First Bone Spring Upper (FBU)	Sandstone/Shale	9,742	9,882	No
First Bone Spring Lower (FBL)	Sandstone/Shale	10,068	10,208	No
Second Bone Spring Upper (SBU)	Sandstone/Shale	10,400	10,540	No
Second Bone Spring Lower (SBL)	Sandstone/Shale	10,911	11,051	No
Third Bone Spring (TBS)	Sandstone/Shale	11,647	11,787	No
Wolfcamp A (WCA)	Sandstone/Shale	12,070	12,224	Yes: Oil & Natural Gas

WELLBORE LOCATIONS	MD	TVD
SHL	-	-
KOP	11,814	11,798
FTP	12,685	12,475
LTP	23,370	12,518
BHL	23,420	12,518

2. **BOP EQUIPMENT AND TESTING**

Rating Depth 12,518 TVD

Equipment
Chevron will have a minimum of a 5,000 psi rig stack for drill out below surface casing and a 10,000 psi rig stack for drilling the production hole section. See attached proposed schematics and 10,000 PSI Annular BOP Variance Request.

Request Variance: Yes
Variance Request(s)
Chevron respectfully request to vary from the 43 CFR 3172 where it states: "(A full BOP Test) shall be performed: when initially installed and whenever any seal subject to test pressure is broken." We propose to break test if able to finish the next hole section within 21 days of the previous full BOP test. No BOP components nor any break will ever surpass 21 days between testing. A break test will consist of a 250 psi low / ≥ 5,000 psi high for 10 min each test against the connection that was broken when skidding the rig. Upon the first nipple up of the pad a full BOP test will be performed. A full BOP test will be completed prior to drilling the production lateral sections unless the BOP connection was not broken prior to drilling that hole section (example: drilling straight from production into production liner hole section). A break test will only be performed on operations where BLM documentation states a 5M or less BOP can be utilized.

Chevron respectfully requests a variance to use a FMC Technologies UH-S Multibowl wellhead, which will be run through the rig floor on surface casing. BOPE will be nippled up and tested after cementing surface casing. Subsequent tests will be performed as needed, not to exceed 30 days. The field report from FMC Technologies and BOP test information will be provided in a subsequent report at the end of the well. Please see the attached wellhead schematic. An installation manual has been placed on file with the BLM office and remains unchanged from previous submittal. All tests performed by third party.

Chevron respectfully requests a variance from the 0.422" annular clearance requirement per 43 CFR3172 for the intermediate 1 (salt) section under the following condition:
1. Annular clearance to meet or exceed 0.422" between intermediate casing ID and production casing connection OD for the first 500' of overlap between both strings.

Testing Procedure
The stack will be tested as specified in the attached testing requirements. Batch drilling of the surface, production, and production liner will take place. A full BOP test will be performed per hole section, unless approval from BLM is received otherwise (see variance request). Flex choke hose will be used for all wells on the pad (see attached specs and variance). BOP test pressures and other documented tests may be recorded and documented via utilization of the Digital BOP Test Method in lieu of the standard test chart. In the event the digital system is unavailable, the standard test chart will be used.

3. **CASING PROGRAM**

a. The proposed PRIMARY casing program will be as follows:

Purpose	Top (MD)	Top (TVD)	Bot (MD)	Bot (TVD)	Hole Size	Csg Size	Weight	Grade	Thread
Surface	0'	0'	1,072'	1,072'	17.5"	13.375"	54.5 #	J-55	BTC
Intermediate 1	0'	0'	4,893'	4,796'	12.25"	10.75"	40.5 #	J-55	BTC
Intermediate 2	0'	0'	11,814'	11,462'	9.875"	7.625"	29.7 #	P-110ICY	W441
Production Liner (Primary)	11,614'	11,262'	23,420'	12,518'	6.75"	5"	13.0 #	P-110ICY	W421
Production Liner (Alternative)	11,614'	11,262'	23,420'	12,518'	6.75"	5-1/2"	17.0 #	P-110ICY	W451

Surface casing set below magenta dolomite and above top of salt (25 ft below los medanos)

b. **All casing strings will be new pipe.**
c. **Casing design depths subject to revision based on directional drilling and geologic conditions encountered.**
d. **Chevon will keep intermediate casing fluid filled at all times and while RIH. Chevron will check casing at a minimum of every 20 jts (~840'), and never to surpass ⅓ of casing, while running intermediate casing in order to maintain collapse SF.**
e. **Chevon will keep 5" 13# Production liner fluid filled at all times and while RIH. Chevron will check casing at a minimum of every 20 jts (~840'), and never to surpass ⅓ of casing, while running prodution liner casing in order to maintain collapse SF.**
f. **The 5.5" 17# W451 Production liner is an alternative liner that will be "floated" in the event of challenges running the 5" 13# fluid-filled liner**

Casing String	Min SF Collapse	Min SF Burst	Min SF Axial (Joint)	Min SF Axial (Body)
Surface	2.03	1.51	15.56	14.60
Intermediate 1	Refer to attached casing design load analysis			
Intermediate 2	1.03	1.94	2.35	3.14
Production Liner (Primary)	Refer to attached casing design load analysis			
Production Liner (Alternative)	1.45	2.52	3.15	3.43

g. All minumum safety factors are calculated in **bouyant** conditions.

4. **CEMENTING PROGRAM**

Slurry	Type	Top	Bottom	*Quantity*	Yield	Density	%Excess	Volume	Additives
Surface Casing 13-3/8"				(sks)	(cuft/sk)	(ppg)		(cuft)	
Lead	Class C	0'	530'	91	2.29	12.8	25	208	Extender, Antifoam, Retarder, Viscosifier
Tail	Class C	530'	1,072'	690	1.35	14.8	25	931	Extender, Antifoam, Retarder, Viscosifier
Intermediate 1 Casing 10-3/4"									
Planned single stage cement job									
Lead	Class C	0'	3,893'	360	2.29	11.5	25	825	Extender, Antifoam, Retarder, Viscosifier
Tail	Class C	3,893'	4,893'	175	1.63	12.6	25	285	Extender, Antifoam, Retarder, Viscosifier
Contingency: Top Job									
1st Tail	Class C	0'	3,893'	857	1.35	14.8	25	1157	Extender, Antifoam, Retarder, Viscosifier
Intermediate 2 Casing 7-5/8"									
Planned single stage cement job									
Lead	Class C	0'	10,814'	777	3.52	10.5	25	2734	Extender, Antifoam, Retarder, Viscosifier
Tail	Class C	10,814'	11,814'	192	1.52	12.6	25	292	Extender, Antifoam, Retarder, Viscosifier
Contingency: Top Job									
1st Tail	Class C	0'	8,814'	1908	1.35	14.8	25	2576	Extender, Antifoam, Retarder, Viscosifier
Production Liner 5									
Lead	Class H	11,614'	23,420'	1089	1.52	12.6	25	1655	Extender, Antifoam, Retarder, Viscosifier

Surface casing shall have at least one centralizer installed on each of the bottom three joints starting with the shoe joint.

5. **MUD PROGRAM**

Top	Bottom	Type	Min MW	Max MW at TD	Additional Charactistics
0'	1,072'	Spud Mud	8.3	10	
1,072'	4,893'	Brine	8.3	11.5	Saturated brine would be used through salt sections.
4,893'	11,814'	WBM/Brine	8.3	12.0	
11,814'	23,420'	OBM	9.0	13.0	Due to wellbore instability in the lateral, may exceed the MW window needed to maintain overburden stresses

A weighting agent and lost circulating material (LCM) will be onsite to mitigate pressure or lost circulation as hole conditions dictate.

If an open reserve pit is not approved by OCD, a closed system will be used consisting of above ground steel tanks and all wastes accumulated during drilling operations will be contained in a portable trash cage and removed from location and deposited in an approved sanitary landfill. If an open reserve pit is in place, pit construction, operation, and closure will follow all applicable rules and regulation. Sanitary wastes will be contained in a chemical porta-toilet and then hauled to an approved sanitary landfill.

All fluids and cuttings will be disposed of in accordance with New Mexico Oil Conservation Division rules and regulations. And transportating of E&P waste will follow EPA regulations and accompanying manifests.

A mud test shall be performed every 24 hours after mudding up to determine, as applicable: density, viscosity, gel strength, filtration, and pH.

Visual mud monitoring equipment shall be in place to detect volume changes indicating loss or gain of circulating fluid volume. When abnormal pressures are anticipated -- a pit volume totalizer (PVT), stroke counter, and flow sensor will be used to detect volume changes indicating loss or gain of circulating fluid volume.

6. **TESTING, LOGGING, AND CORING**

a. **Production tests are not planned.**
b. Logs run include: **Gamma Ray Log, Directional Survey**
Neutron log exception granted by BLM Geologist C. Armistead on 6/11/2024
c. **Coring Operations are not planned.**

7. **ABNORMAL PRESSURES AND HYDROGEN SULFIDE**

Anticipated BHP	**8,462**	psi
Anticipated BHT	**218**	°F
Anticipated abnormal pressures?	**Yes**	
Describe abnormal pressures	Pressure ramp begins in the bottom of the Third Bone Spring formation	
Contingency plan(s) description:	- Casing design accounts for pressure ramp - Mud weighting agents available on location to increase drilling fluid density - BOP, choke, and well control drills - BOP functioned and pressure tested	

Hydrogen sulfide gas is not anticipated: However the H2S Contingency plan is attached with this APD in the event that H2S is encountered

8. **OTHER ITEMS**

a. **Batch drilling** will be employed whereby the drilling rig may drill a specific hole section on all wells prior to moving to the next hole section.
b. **Shallow rig** may be utilized to drill surface or intermediate sections. The production section will not be drilled by the shallow rig.
c. **Wait on cement** duration for surface and intermediate string(s) will be based on time for tail slurry to develop 500 psi compressive strength and will follow rules as laid out in 43 CFR 3172
d. **Offline cementing** will be employed on the hole sections that run a long string casing to surface. Offline cementing schematic below.

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

CONDITIONS

Action 542265

CONDITIONS

Operator:	
CHEVRON U S A INC 6301 Deauville Blvd Midland, TX 79706	OGRID: 4323
	Action Number: 542265
	Action Type: [C-103] NOI Change of Plans (C-103A)

CONDITIONS

Created By	Condition	Condition Date
matthew.gomez	All previous COA’s still apply.	3/26/2026