Form 3160-5
(June 2015)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

OCD Hobbs

FORM APPROVED
OMB NO. 1004-0137
Expires: January 31, 2018

SUNDRY NOTICES AND REPORTS ON WELLS

HOBBS OCD

Do not use this form for proposals to drill or to re-enter an abandoned well. Use form 3160-3 (APD) for such proposals.

AUG 29 2017

SUBMIT IN TRIPLICATE - Other instructions on page 2

RECEIVED

5. Lease Serial No.
NMNM27506

6. If Indian, Allottee or Tribe Name

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

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

8. Well Name and No.
SD EA 29 FED COM P8 12H

2. Name of Operator
CHEVRON USA INC

Contact: DENISE PINKERTON
E-Mail: leakejd@chevron.com

9. API Well No.
30-025-43271-00-X1

3a. Address
1616 W. BENDER BLVD
HOBBS, NM 88240

3b. Phone No. (include area code)
Ph: 432-687-7375

10. Field and Pool or Exploratory Area
WC025G06S263319P-BONE SPRING

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
Sec 29 T26S R33E NWNE 136FNL 1607FEL

11. County or Parish, State
LEA COUNTY, 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
☐ Subsequent Report	☐ Alter Casing	☐ Hydraulic Fracturing	☐ Reclamation	☐ Well Integrity
☐ Final Abandonment Notice	☐ Casing Repair	☐ New Construction	☐ Recomplete	☒ Other Change to Original APD
	☐ Change Plans	☐ Plug and Abandon	☐ Temporarily Abandon	
	☐ Convert to Injection	☐ Plug Back	☐ Water Disposal	

13. Describe Proposed or Completed Operation: Clearly state all pertinent details, including estimated starting date of any proposed work and approximate duration thereof. If the proposal is to deepen directionally or recomplete horizontally, give subsurface locations and measured and true vertical depths of all pertinent markers and zones. Attach the Bond under which the work will be performed or provide the Bond No. on file with BLM/BIA. Required subsequent reports 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 determined that the site is ready for final inspection.

CHEVRON respectfully requests the ability to change the BOPE rating for the subject well, from a 5M system to a 10M system while drilling the production sections that penetrate the Wolfcamp formation.

Please find attached:
New 9 PT PLAN
10M BOP CHOKE
UH-2 10K
Choke Hose Spec
7.625 Casing Liner
9.625 43.5lb LTC
Inspection & Test Certificate

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

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

Electronic Submission #385031 verified by the BLM Well Information System
For CHEVRON USA INC, sent to the Hobbs
Committed to AFMSS for processing by ZOTA STEVENS on 08/23/2017 (17ZS0012SE)

Name *(Printed/Typed)* DENISE PINKERTON — Title PERMITTING SPECIALIST

Signature (Electronic Submission) — Date 08/17/2017

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By ZOTA STEVENS — Title PETROLEUM ENGINEER — Date 08/24/2017

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 Hobbs

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)

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

Additional data for EC transaction #385031 that would not fit on the form

32. Additional remarks, continued

Tenaris XP BTC
5" 18# P110 ICY (3 schematics)

This sundry is at the request of Seven, BLM.

Any questions/concerns should be directefd to Bryson Abney, Chevron Drilling Engr, at 713-372-6447.

1. FORMATION TOPS

The estimated tops of important geologic markers are as follows:

FORMATION	SUB-SEA TVD	KBTVD	MD
Rustler		800	
Castile		3480	
Lamar		4900	
Bell Canyon		4930	
Cherry Canyon		5970	
Brushy Canyon		7620	
Bone Spring Limestone		9090	
Upr. Avalon		9120	
Top Bone Spring 1		10040	
Top Bone Spring 2		10700	
Top Bone Spring 3		11740	
Wolfcamp		12140	
Wolfcamp A1		12193	
Wolfcamp A2		12,523	
Lateral TD (Wolfcamp A2)		12,523	20000

2. ESTIMATED DEPTH OF WATER, OIL, GAS & OTHER MINERAL BEARING FORMATIONS

The estimated depths at which the top and bottom of the anticipated water, oil, gas, or other mineral bearing formations are expected to be encountered are as follows:

Substance	Formation	Depth
Deepest Expected Base of Fresh Water		700
Water	Rustler	800
Water	Bell Canyon	4930
Water	Cherry Canyon	5970
Oil/Gas	Brushy Canyon	7620
Oil/Gas	Bone Spring Limestone	9090
Oil/Gas	Upr. Avalon	9120
Oil/Gas	Top Bone Spring 1	10040
Oil/Gas	Top Bone Spring 2	10700
Oil/Gas	Top Bone Spring 3	11740
Oil/Gas	Wolfcamp	12140
Oil/Gas	Wolfcamp A1	12193
Oil/Gas	Wolfcamp A2	12,523

All shows of fresh water and minerals will be reported and protected.

3. BOP EQUIPMENT

Will have a minimum of a 10000 psi rig stack (see proposed schematic) for drill out below surface (Wolfcamp is not exposed until drillout of the intermediate casing). Could possibly utilize the 5000 psi rig stack (see proposed schematic) for drill out below surface casing due to the availabity of 10 M annular. (Wolfcamp is not exposed until drillout of the intermediate casing) Stack will be tested as specified in the attached testing requirements. Batch drilling of the surface, intermediate, and production will take place. A full BOP test will be performed unless approval from BLM is received otherwise. Flex choke hose will be used for all wells on the pad (see attached specs) BOP test will be conducted by a third party.

Chevron requests a variance to use a FMC UH2 Multibowl wellhead, which will be run through the rig foor 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 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.

4. **CASING PROGRAM**

a. The proposed casing program will be as follows:

Purpose	From	To	Hole Size	Csg Size	Weight	Grade	Thread	Condition
Surface	0'	800'	17-1/2"	13-3/8"	54.5 #	J55	STC	New
Intermediate	0'	11,500'	12-1/4"	9-5/8"	43.5#	HCK-L80	LTC	New
Liner	10,850'	12,300'	8-1/2"	7-5/8"	29.7 #	HCP-110	H513	New
Production (Taper String)	0'	12,500'	6-3/4"	5.5"	20#	P-110-ICY	TXP BTC	New
	12,500'	20,000'	6-3/4"	5"	18#	P-110 IC	TSH521	New

b. Casing design subject to revision based on geologic conditions encountered.

c. *****A "Worst Case" casing design for wells in a particular area is used below to calculate the Casing Safety Factors. If for any reason the casing design for a particular well requires setting casing deeper than the following "worst case" design, then the Casing Safety Factors will be recalcuated & sent to the BLM prior to drilling.**

d. **Chevron will fill casing at a minimum of every 20 jts (840') while running for intermediate and production casing in order to maintain collapse SF.**

SF Calculations based on the following "Worst Case" casing design:

Surface Casing: 850'
Intermediate Casing: 11,200' TVD
Production Casing: 23,000' MD/12,750' TVD (10,300' VS @ 90 deg inc)

Casing String	Min SF Burst	Min SF Collapse	Min SF Tension	Min SF Tri-Axial
Surface	1.36	3.12	3.17	1.70
Intermediate	1.12	1.44	1.93	1.37
Liner	1.69	5.36	2.50	2.09
Production	1.11	1.23	1.97	1.37

Min SF is the smallest of a group of safety factors that include the following considerations:

Burst Design	Surf	Int	Liner	Prod
Pressure Test- Surface, Int, Prod Csg P external: Water P internal: Test psi + next section heaviest mud in csg	X	X	X	X
Displace to Gas- Surf Csg P external: Water P internal: Dry Gas from Next Csg Point	X			
Frac at Shoe, Gas to Surf- Int Csg P external: Water P internal: Dry Gas, 16 ppg Frac Gradient		X	X	
Stimulation (Frac) Pressures- Prod Csg P external: Water P internal: Max inj pressure w/ heaviest injected fluid				X
Tubing leak- Prod Csg (packer at KOP) P external: Water P internal: Leak just below surf, 8.7 ppg packer fluid				X
Collapse Design				
Full Evacuation P external: Water gradient in cement, mud above TOC P internal: none	X	X	X	X
Cementing- Surf, Int, Prod Csg P external: Wet cement P internal: water	X	X	X	X
Tension Design				
100k lb overpull	X	X	X	X

5. **CEMENTING PROGRAM**

Slurry	Type	Top	Bottom	Weight	Yield	%Excess	Sacks	Water
Surface				(ppg)	(sx/cu ft)	Open Hole		gal/sk
Tail	Class C	0'	800'	14.8	1.33	50	650	6.57
Intermediate								
Stage 2 Lead	Class C	0'	4570	11.9	2.39	100	1070	13.46
Stage 2 Tail	Class C	4570	4870	14.8	1.33	25	89	6.35
Stage 1 Lead	50:50 Poz Class C	4,870'	10,650'	11.9	2.21	25	1024	12.18
Stage 1 Tail	Class H	10,650'	11,150'	15.6	1.22	25	184	5.37
Liner								
Tail	Class H	10,850'	12,300'	15.6	1.22	17	123	5.34
Production								
Tail	Acid Soluble	10,350'	23,000'	15.6	1.2	10	1000	5.05
Pilot Hole								
Tail	Class H	12,500'	13,000'	17.2	0.97	10	128	3.61

1. Final cement volumes will be determined by caliper.
2. Surface casing shall have at least one centralizer installed on each of the bottom three joints starting with the shoe joint.
3. Production casing will have one horizontal type centralizer on every joint for the first 1000' from TD, then every other joint to EOB, and then every third joint to KOP. Bowspring type centralizers will be run from KOP to intermediate casing.

6. MUD PROGRAM

From	To	Type	Weight	F. Vis	Filtrate
0'	800'	Spud Mud	8.3 - 8.7	32 - 34	NC - NC
800'	11,150'	Oil Based Mud	8.7-9.2	28 - 30	25-30
11,150'	12,300'	Oil Based Mud	9.5-13.5	70 - 75	25 - 30
12,300'	20,000'	Oil Based Mud	12.0-15.0	70 - 75	25 - 30

A closed system will by utilized consisting of above ground steel tanks. 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. 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.

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.

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

7. TESTING, LOGGING, AND CORING

The anticipated type and amount of testing, logging, and coring are as follows:

a. Drill stem tests are not planned.
b. The logging program will be as follows:

TYPE	Logs	Interval	Timing	Vendor
Mudlogs	2 man mudlog	Int Csg to TD	Drillout of Int Csg	TBD
LWD	MWD Gamma	Int. and Prod. Hole	While Drilling	TBD
Wireline Logs	Quad Combo w/ Di-Pole Sonic, FMI	Production	After production liner	TBD

c. Conventional whole core samples are not planned.
d. A Directional Survey will be run.

8. ABNORMAL PRESSURES AND HYDROGEN SULFIDE

a. No abnormal pressures or temperatures are expected. Estimated BHP at intermediate TD is: 5750 psi
No abnormal pressures or temperatures are expected. Estimated BHP at production TD is: 9830 psi
b. Hydrogen sulfide gas is not anticipated. An H2S Contingency plan is attached with this APD in the event that H2S is encountered

BLOWOUT PREVENTOR SCHEMATIC

Minimum Requirements

OPERATION : Wolfcamp A/A2 Wells

Minimum System Pressure Rating : 10,000 psi

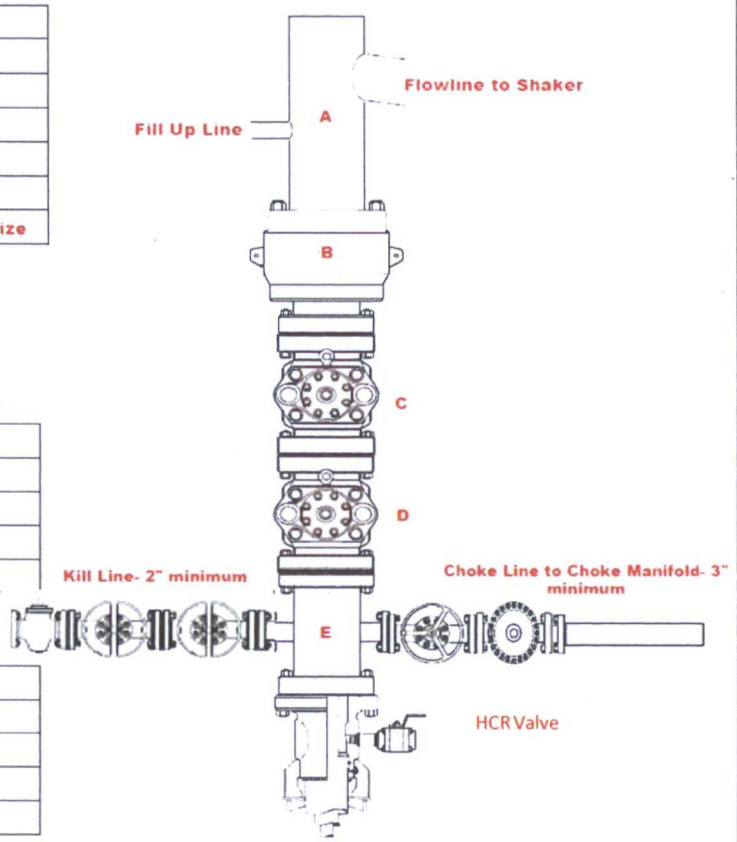
	SIZE	PRESSURE	DESCRIPTION
A		N/A	Bell Nipple
B	13 5/8"	10,000 psi	Annular
C	13 5/8"	10,000 psi	Pipe Ram
D	13 5/8"	10,000 psi	Blind Ram
E	13 5/8"	10,000 psi	Mud Cross
F	13 5/8"	10,000 psi	Pipe Ram
DSA		As required for each hole size	

Kill Line

SIZE	PRESSURE	DESCRIPTION
2"	10,000 psi	Gate Valve
2"	10,000 psi	Gate Valve
2"	10,000 psi	Check Valve

Choke Line

SIZE	PRESSURE	DESCRIPTION
3"	10,000 psi	Gate Valve
3"	10,000 psi	HCR Valve



Installation Checklist

The following item must be verified and checked off prior to pressure testing of BOP equipment.

- ☐ The installed BOP equipment meets at least the minimum requirements (rating, type, size, configuration) as shown on this schematic. Components may be substituted for equivalent equipment rated to higher pressures. Additional components may be put into place as long as they meet or exceed the minimum pressure rating of the system.
- ☐ All valves on the kill line and choke line will be full opening and will allow straight though flow.
- ☐ The kill line and choke line will be straight unless turns use tee blocks or are targeted with running tess, and will be anchored to prevent whip and reduce vibration.
- ☐ Manual (hand wheels) or automatic locking devices will be installed on all ram preventers. Hand wheels will also be installed on all manual valves on the choke line and kill line.
- ☐ A valve will be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve will remain open unless accumulator is inoperative.
- ☐ Upper kelly cock valve with handle will be available on rig floor along with safety valve and subs to fit all drill string connections in use.

After Installation Checklist is complete, fill out the information below and email to Superintendent and Drilling Engineer

Wellname: _____

Representative: _____

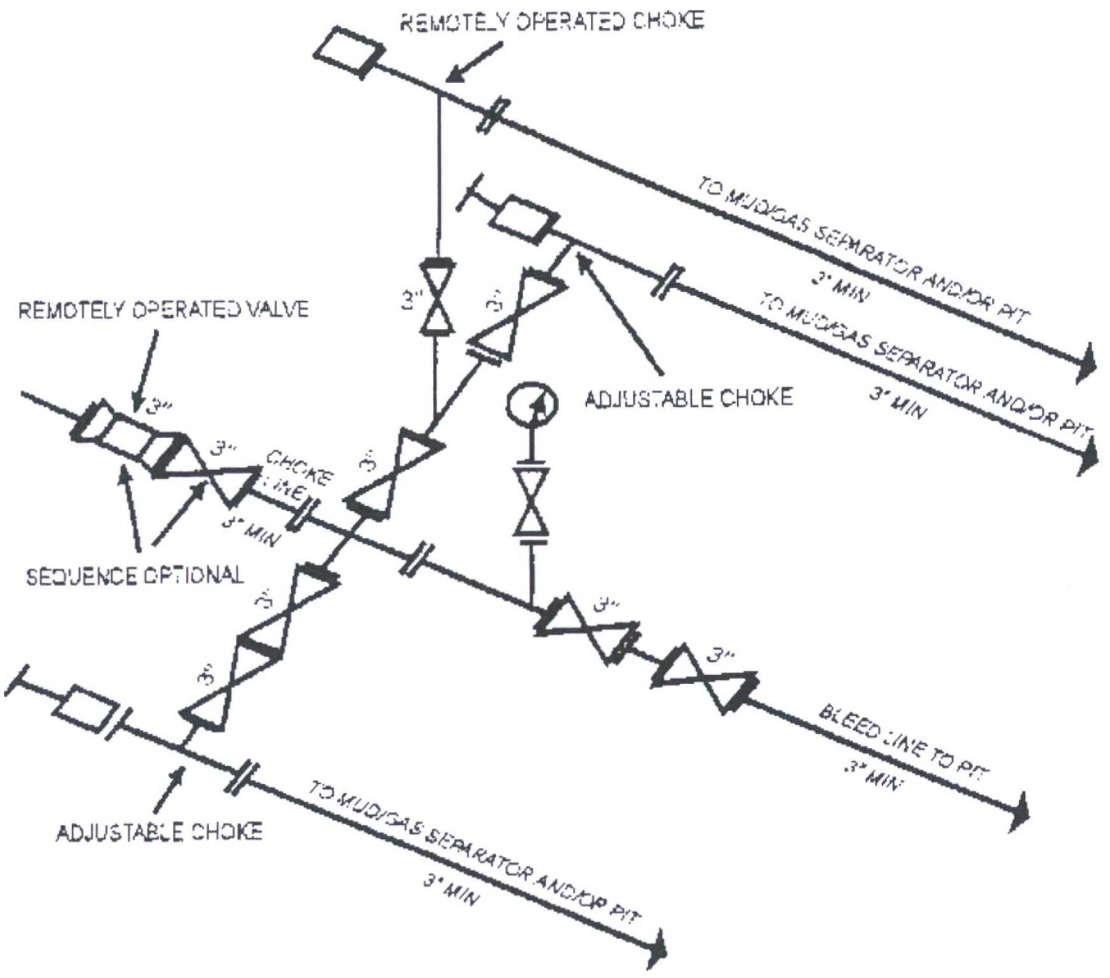
Date: _____

10M Choke Manifold SCHEMATIC

Minimum Requirements

OPERATION: Production and Open Hole Sections

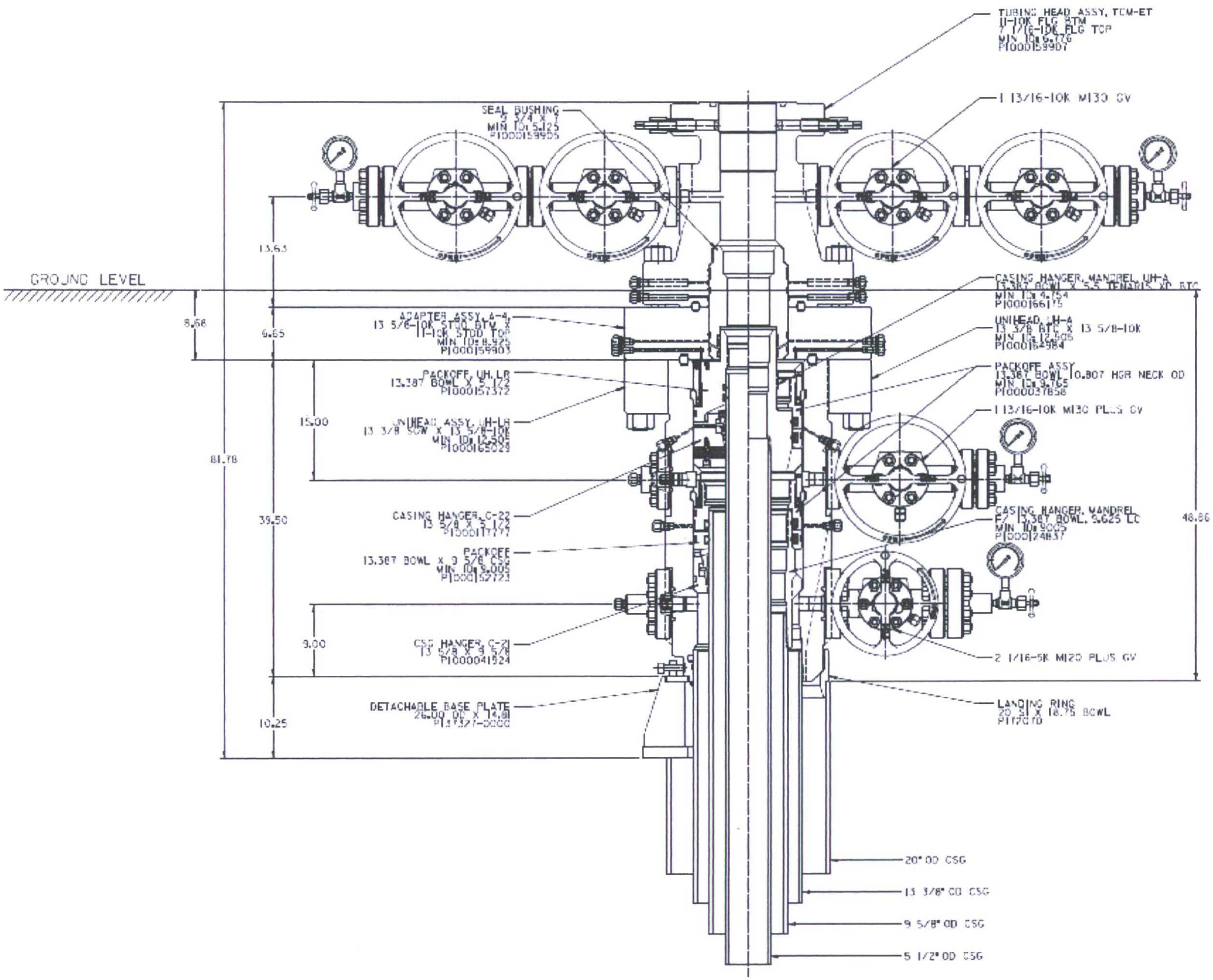
Minimum System Pressure Rating: 10,000 PSI



10M AND 15M CHOKE MANIFOLD EQUIPMENT - CONFIGURATION OF CHOKES MAY VARY

[53 FR 49661, Dec. 9, 1988 and 54 FR 39528, Sept. 27, 1989]

Diagram B



TUBING HEAD ASSY, TCM-ET
11-10K FLG BTM
7 1/16-10K FLG TOP
MIN ID: 6.776
P1000159907
1 13/16-10K M130 GV
SEAL BUSHING
9 3/4 X 7
MIN ID: 5.125
P1000159905
GROUND LEVEL
13.63
8.68
6.65
81.78
15.00
39.50
9.00
10.25
48.86
ADAPTER ASSY, A-4,
13 5/8-10K STUD BTM X
11-10K STUD TOP
MIN ID: 8.925
P1000159903
PACKOFF, UH, LR
13.387 BOWL X 5 1/2
P1000157372
UNIHEAD ASSY, UH-LR
13 3/8 SOW X 13 5/8-10K
MIN ID: 12.505
P1000165029
CASING HANGER, C-22
13 5/8 X 5 1/2
P1000117777
PACKOFF
13.387 BOWL X 9 5/8 CSG
MIN ID: 9.005
P1000152723
CSG HANGER, C-21
13 5/8 X 9 5/8
P1000041524
DETACHABLE BASE PLATE
26.00 OD X 14.81
P137327-0000
CASING HANGER, MANDREL, UH-A
13.387 BOWL X 5.5 TENARIS XP BTC
MIN ID: 4.754
P1000166175
UNIHEAD, UH-A
13 3/8 BTC X 13 5/8-10K
MIN ID: 12.505
P1000164984
PACKOFF ASSY
13.387 BOWL 10.807 HGR NECK OD
MIN ID: 9.765
P1000037858
1 13/16-10K M130 PLUS GV
CASING HANGER, MANDREL
F/ 13.387 BOWL, 9.625 LC
MIN ID: 9.005
P1000124837
2 1/16-5K M120 PLUS GV
LANDING RING
20 3/4 X 18.75 BOWL
P117070
20" OD CSG
13 3/8" OD CSG
9 5/8" OD CSG
5 1/2" OD CSG

Continental

ContiTech

Hose Data Sheet

CRI Order No.	538332
Customer	ContiTech Oil & Marine Corp.
Customer Order No	4500412631 CBC544771, CBC544769, CBC544767, CBC544763, CBC544768, CBC544745, CBC544744, CBC544746
Item No.	1
Hose Type	Flexible Hose
Standard	**API SPEC 16 C**
Inside dia in inches	3
Length	45 ft
Type of coupling one end	FLANGE 4.1/16" 10KPSI API SPEC 17D SV SWIVEL FLANGE SOURC/W BX155 ST/ST INLAID R.GR.
Type of coupling other end	FLANGE 4.1/16" 10KPSI API SPEC 17D SV SWIVEL FLANGE SOUR C/W BX155 ST/ST INLAID R.GR.
H2S service NACE MR0175	Yes
Working Pressure	10 000 psi
Design Pressure	10 000 psi
Test Pressure	15 000 psi
Safety Factor	2,25
Marking	USUAL PHOENIX
Cover	NOT FIRE RESISTANT
Outside protection	St.steel outer wrap
Internal stripwound tube	No
Lining	OIL + GAS RESISTANT SOUR
Safety clamp	Yes
Lifting collar	Yes
Element C	Yes
Safety chain	Yes
Safety wire rope	No
Max.design temperature [°C]	100
Min.design temperature [°C]	-20
Min. Bend Radius operating [m]	0,90
Min. Bend Radius storage [m]	0,90
Electrical continuity	The Hose is electrically continuous
Type of packing	WOODEN CRATE ISPM-15

Wed Jun 17 2015

Tenaris

Casing and Tubing Performance Dat

PIPE BODY DATA

GEOMETRY

Outside Diameter	9.625 in	Wall Thickness	0.435 in	API Drift Diameter	8.599 in
Nominal Weight	43.50 lbs/ft	Nominal ID	8.755 in	Alternative Drift Diameter	8.625 in
Plain End Weight	42.73 lbs/ft	Nominal cross section	12.559 in		

PERFORMANCE

Steel Grade	L80	Minimum Yield	80,000 psi	Minimum Ultimate	95,000 psi
Tension Yield	1,005,000 in	Internal Pressure Yield	6,330 psi	Collapse Pressure	3,810 psi
Available Seamless	Yes	Available Welded	No		

CONNECTION DATA

TYPE: LTC

GEOMETRY

Coupling Reg OD	10.625 in	Threads per in	8	Thread turns make up	3.5

PERFORMANCE

Steel Grade	L80	Coupling Min Yield	80,000 psi	Coupling Min Ultimate	95,000 psi
Joint Strength	813,000 lbs			Internal Pressure Resistance	6,330 psi

For the latest performance data, always visit our website: www.tenaris.com

June 17 2015

TenarisHydril

Size: 7.625 in.
Wall: 0.375 in.
Weight: 29.70 lbs/ft
Grade: P110-IC
Min. Wall Thickness: 87.5 %

Connection: Wedge 513™
Casing/Tubing: CAS

PIPE BODY DATA

GEOMETRY

Nominal OD	**7.625** in.	Nominal Weight	**29.70** lbs/ft	Standard Drift Diameter	**6.750** in.
Nominal ID	**6.875** in.	Wall Thickness	**0.375** in.	Special Drift Diameter	**N/A**
Plain End Weight	**29.06** lbs/ft				

PERFORMANCE

Body Yield Strength	**940** x 1000 lbs	Internal Yield	**9470** psi	SMYS	**110000** psi
Collapse	**7150** psi				

WEDGE 513™ CONNECTION DATA

GEOMETRY

Connection OD	**7.625** in.	Connection ID	**6.800** in.	Make-Up Loss	**4.420** in.
Critical Section Area	**5.125** sq. in.	Threads per in.	**3.29**		

PERFORMANCE

Tension Efficiency	**60.0** %	Joint Yield Strength	**564** x 1000 lbs	Internal Pressure Capacity	**9470** psi
Compression Strength	**707** x 1000 lbs	Compression Efficiency	**75.2** %	Bending	**40** °/100 ft
External Pressure Capacity	**7150** psi				

MAKE-UP TORQUES

Minimum	**9000** ft-lbs	Optimum	**10800** ft-lbs	Maximum (*)	**15800** ft-lbs

OPERATIONAL LIMIT TORQUES

Operating Torque	**47000** ft-lbs	Yield Torque	**70000** ft-lbs		

BLANKING DIMENSIONS

For the latest performance data, always visit our website: www.tenaris.com

January 18 2016

Tenaris

Size: 5.500 in.
Wall: 0.361 in.
Weight: 20.00 lbs/ft
Grade: P110-ICY
Min. Wall Thickness: 87.5 %

Connection: TenarisXP® BTC
Casing/Tubing: CAS
Coupling Option: REGULAR

PIPE BODY DATA

GEOMETRY

Nominal OD	**5.500** in.	Nominal Weight	**20.00** lbs/ft	Standard Drift Diameter	**4.653** in.
Nominal ID	**4.778** in.	Wall Thickness	**0.361** in.	Special Drift Diameter	**N/A**
Plain End Weight	**19.83** lbs/ft				

PERFORMANCE

Body Yield Strength	**729** x 1000 lbs	Internal Yield	**14360** psi	SMYS	**125000** psi
Collapse	**12100** psi				

TENARISXP® BTC CONNECTION DATA

GEOMETRY

Connection OD	**6.100** in.	Coupling Length	**9.450** in.	Connection ID	**4.766** in.
Critical Section Area	**5.828** sq. in.	Threads per in.	**5.00**	Make-Up Loss	**4.204** in.

PERFORMANCE

Tension Efficiency	**100** %	Joint Yield Strength	**729** x 1000 lbs	Internal Pressure Capacity(1)	**14360** psi
Structural Compression Efficiency	**100** %	Structural Compression Strength	**729** x 1000 lbs	Structural Bending(2)	**104** °/100 ft
External Pressure Capacity	**12100** psi				

ESTIMATED MAKE-UP TORQUES(3)

Minimum	**11540** ft-lbs	Optimum	**12820** ft-lbs	Maximum	**14100** ft-lbs

OPERATIONAL LIMIT TORQUES

Operating Torque	**22700** ft-lbs	Yield Torque	**25250** ft-lbs		

BLANKING DIMENSIONS

Blanking Dimensions

Tenaris

Data Sheet

TH DS-16.0370 11 ago 16
Rev 00

5" 18.00 ppf P110-ICY - TenarisXP® BTC (min wt 90%)
(USC Units)

PIPE BODY DATA					
GEOMETRY					
Nominal OD	5.000 in.	Nominal Weight	18.00 lbs/ft	Standard Drift Diameter	4.151 in.
Nominal ID	4.276 in.	Wall Thickness	0.362 in.	Special Drift Diameter	-
Plain End Weight	17.95 lbs/ft				
PERFORMANCE					
Body Yield Strength	659 x 1000 lbs	Internal Yield [4]	16290 psi	Collapse	14840 psi

CONNECTION DATA					
Regular OD	5.720 in.	Coupling Length	9.325 in.	Connection ID	4.264 in.
Critical Section Area	5.275 sq. in.	Threads per in.	5	Make-Up Loss	4.141 in.
PERFORMANCE					
Tension Efficiency	100.0 %	Joint Yield Strength	659 x 1000 lbs	Internal Pressure Capacity [1] [4]	16290 psi
Structural Compression Efficiency	100.0 %	Structural Compression Rating	659 x 1000 lbs	External Pressure Capacity	14840 psi
Structural Bending [2]	115°/100 ft				
MAKE-UP TORQUES [3]					
Minimum	11480 ft-lbs	Target	12750 ft-lbs	Maximum	14030 ft-lbs
Operating Torque	15800 ft-lbs	Yield Torque	17700 ft-lbs		

(1) Internal Yield pressure related to structural resistance only. Internal pressure leak resistance as per section 10.3 API 5C3 / ISO 10400 - 2007.

(2) Structural rating, pure bending to yield (i.e no other loads applied)

(3) Torque values calculated for API Modified thread compounds with Friction Factor=1. For other thread compounds please contact us at licensees@oilfield.tenaris.com.

(4) Minimum wall thickness 90% of nominal

TenarisHydril

Data Sheet

TH DS-16.0372 23 August 2016
Rev 00

5.000" 18.00 lb/ft P110-ICY TenarisHydril Wedge 521®

PIPE BODY DATA					
GEOMETRY					
Nominal OD	5.000 in.	**Nominal Weight**	18.00 lbs/ft	**Standard Drift Diameter**	4.151 in.
Nominal ID	4.276 in.	**Wall Thickness**	0.362 in.	**Special Drift Diameter**	N/A
Plain End Weight	17.95 lbs/ft				
PERFORMANCE					
Body Yield Strength	659 x 1000 lbs	**Internal Yield[1]**	16290 psi	**Collapse**	14840 psi

CONNECTION DATA					
GEOMETRY					
Box OD (Turned)	5.359 in.	**Pin ID (Bored)**	4.226 in.	**Make-Up Loss**	3.62 in.
Critical Section Area	3.891 sq. in.	**Threads per in.**	3.36		
PERFORMANCE					
Tension Efficiency	73.8 %	**Joint Yield Strength**	486 x 1000 lbs	**Internal Yield[1]**	16290 psi
Compression Efficiency	88.7 %	**Compression Rating**	585 x 1000 lbs	**Collapse**	14840 psi
Bending	85°/100 ft				
MAKE-UP TORQUES					
Minimum	6100 ft-lbs	**Optimum**	7300 ft-lbs	**Maximum***	10700 ft-lbs
OPERATIONAL LIMIT TORQUES					
Operational	20000 ft-lbs			**Yield Torque**	30000 ft-lbs

*If you need to use torque values that are higher than the maximum indicated, please contact a local Tenaris technical sales representative

1. Internal Yield Rating is based on 90% RBW.

PECOS DISTRICT
CONDITIONS OF APPROVAL

OPERATOR'S NAME:	Chevron USA Inc
LEASE NO.:	NM27506
WELL NAME & NO.:	12H-SD EA 29 Fed Com P8
SURFACE HOLE FOOTAGE:	136'/N & 1607'/E
BOTTOM HOLE FOOTAGE	180'/S & 330'/E
LOCATION:	Section 29, T. 26 S., R.33 E., NMPM
COUNTY:	Lea County, New Mexico

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Standard Conditions of Approval (COA) apply to this APD. If any deviations to these standards exist or special COAs are required, the section with the deviation or requirement will be checked below.

I. SPECIAL REQUIREMENT(S)

Communitization Agreement

- The operator will submit a Communitization Agreement to the Carlsbad Field Office, 620 E Greene St. Carlsbad, New Mexico 88220, 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.
- 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. When the Communitization Agreement number is known, it shall also be on the sign.

Waste Minimization Plan (WMP)

In the interest of resource development, submission of additional well gas capture development plan information is deferred but may be required by the BLM Authorized Officer at a later date.

DRILLING

A. DRILLING OPERATIONS REQUIREMENTS

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

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

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

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

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

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

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

B. CASING

Changes to the approved APD casing program need prior approval if the items substituted are of lesser grade or different casing size. 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.).

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

Wait on cement (WOC) for Water Basin:

After cementing but before commencing any tests, the casing string shall stand cemented under pressure until both of the following conditions have been met: 1) cement reaches a minimum compressive strength of 500 psi at the shoe, 2) until cement has been in place at least 8 hours. WOC time will be recorded in the driller's log. See individual casing strings for details regarding lead cement slurry requirements.

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

Medium Cave/Karst
Possible water flows in the Salado and Castile.
Possible lost circulation in the Red Beds, Rustler, and Delaware.
Abnormal pressures may be encountered within the 3rd Bone Spring Sandstone and Wolfcamp.

1. The **13-3/8** inch surface casing shall be set at approximately **850** feet (**in a competent bed below the Magenta Dolomite, which is a Member of the Rustler, and if salt is encountered, set casing at least 25 feet above the salt**) and cemented to the surface.
    a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement. Temperature survey will be run a minimum of six hours after pumping cement and ideally between 8-10 hours after completing the cement job.

    b. Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry.

    c. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.

    d. If cement falls back, remedial cementing will be done prior to drilling out that string.

2. The minimum required fill of cement behind the **9-5/8** inch intermediate casing is:

Operator has proposed DV tool at depth of ', but will adjust cement proportionately if moved. DV tool shall be set a minimum of 50' below previous shoe and a minimum of 200' above current shoe. Operator shall submit sundry if DV tool depth cannot be set in this range.

a. First stage to DV tool:

☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office before proceeding with second stage cement job. Operator should have plans as to how they will achieve circulation on the next stage. **Excess calculates to 19% - Additional cement may be required.**

b. Second stage above DV tool:

☒ Cement to surface. If cement does not circulate, contact the appropriate BLM office.

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

Medium Cave/Karst: If cement does not circulate to surface on the intermediate casing, the cement on the production casing must come to surface.

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

☒ Cement should tie-back at least 200 feet into previous casing string. Operator shall provide method of verification.

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

C. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. **Operator has proposed a multi-bowl wellhead assembly. This assembly will only be tested when installed on the surface casing. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the surface casing shoe shall be 10,000 (10M) 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. **Operator shall perform the intermediate casing integrity test to 70% of the casing burst. This will test the multi-bowl seals.**
    e. **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.**

10M system requires an HCR valve, remote kill line and annular to match. The remote kill line is to be installed prior to testing the system and tested to stack pressure.

3. The appropriate BLM office shall be notified a minimum of 4 hours in advance for a representative to witness the tests.

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

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

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

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

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

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

D. DRILL STEM TEST

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

E. 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.

ZS 082417

13 3/8	surface csg in a	17 1/2	inch hole.		Design Factors		SURFACE	
Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	Weight
"A"	54.50	J 55	ST&C	11.10	2.94	0.5	850	46,325
"B"							0	0
w/8.4#/g mud, 30min Sfc Csg Test psig:	1,500	Tail Cmt	does	circ to sfc.	Totals:		850	46,325

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	650	865	645	34	8.70	2966	3M	1.56

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

9 5/8	casing inside the	13 3/8	A Buoyant		Design Factors		INTERMEDIATE	
Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	Weight
"A"	40.00	HCK 55	LT&C	2.03	0.69	0.74	11,500	460,000
"B"							0	0
w/8.4#/g mud, 30min Sfc Csg Test psig:						Totals:	11,500	460,000
The cement volume(s) are intended to achieve a top of			0	ft from surface or a			850	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	0.3132	look ↘	0	3662		9.20	5886	10M	0.81
D V Tool(s):			4870				sum of sx	Σ CuFt	Σ%excess
t by stage % :		19	71				2367	5163	41

Class 'H' tail cmt yld > 1.20 MASP is within 10% of 5000psig, need

Burst Frac Gradient(s) for Segment(s): A, B, C, D = 0.55, b, c, d
<0.70 a Problem!!

Tail cmt

7 5/8	Liner w/top @	#####			Design Factors		LINER	
Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	Weight
"A"	29.70	HCP 110	LT&C	2.39	0.78	0.93	1,380	40,986
"B"	29.70	HCP 110	LT&C	1.75	0.83	0.93	70	2,079
w/8.4#/g mud, 30min Sfc Csg Test psig:	1,292					Totals:	1,450	43,065
A would be:				13.10	0.83	if it were a vertical wellbore.		

No Pilot Hole Planned	MTD	Max VTD	Csg VD	Curve KOP	Dogleg°	Severity°	MEOC
	12300	12230	12230	12201	90	14	12865

The cement volume(s) are intended to achieve a top of 3950 ft from surface or a 7550 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
8 1/2	0.0770	123	150	893	-83	13.50	7270	10M	0.44

Class 'H' tail cmt yld > 1.20 MASP is within 10% of 5000psig, need exrta equip?

Burst Frac Gradient(s) for Segment(s): A, B, C, D = CURVE SAFETY FACTOR IS TOO CONSERVATIVE

Tail cmt

5 1/2	casing inside the	7 5/8			Design Factors		PRODUCTION	
Segment	#/ft	Grade	Coupling	Joint	Collapse	Burst	Length	Weight
"A"	20.00	P 110	BUTT	1.82	1.27	1.42	12,201	244,016
"B"	20.00	P 110	BUTT	1.95	1.16	1.42	7,799	155,984
"C"	18.00	P 110	BUTT	360.00	1.51	1.61	7,500	135,000
"D"							0	0
w/8.4#/g mud, 30min Sfc Csg Test psig:	2,684					Totals:	27,500	535,000
B egment Design Factors would be:				4.63	1.24	if it were a vertical wellbore.		

500799.209999999999	MTD	Max VTD	Csg VD	Curve KOP	Dogleg°	Severity°	MEOC
	20000	13000	12575	12201	90	12	12951.85

The cement volume(s) are intended to achieve a top of 0 ft from surface or a 12300 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	1000	1200	552	118	15.00			0.33

Capitan Reef est top XXXX. MASP is within 10% of 5000psig, need exrta equip?

5.5" CASING DEPTH CLEARANCE IS EXPECTABLE