Form 3160-5
(June 2015)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

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

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.

5. Lease Serial No.
NMNM16348

6. If Indian, Allottee or Tribe Name

NM OIL CONSERVATION
ARTESIA DISTRICT

MAR 11 2019

RECEIVED

SUBMIT IN TRIPLICATE - Other instructions on page 2

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

1. Type of Well ☒ Oil Well ☐ Gas Well ☐ Other	8. Well Name and No. LUSITANO 27-34 FED COM 624H
2. Name of Operator DEVON ENERGY PRODUCTION COMPANY Contact: LINDA GOOD E-Mail: linda.good@dvn.com	9. API Well No. 30-015-45632-00-X1
3a. Address 6488 SEVEN RIVERS HIGHWAY ARTESIA, NM 88210 3b. Phone No. (include area code) Ph: 405-552-6558	10. Field and Pool or Exploratory Area PURPLE SAGE-WOLFCAMP (GAS)
4. Location of Well (*Footage, Sec., T., R., M., or Survey Description*) Sec 27 T25S R31E NWNE 235FNL 1934FEL 32.107910 N Lat, 103.763596 W Lon	11. County or Parish, State EDDY 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 Drilling Operations
	☐ 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.

Devon Energy Production Co., LP respectfully request permission to make the following changes to the Drilling Plan:

These changes are being made to include our most appropriate casing design. The primary casing design has been updated.

The following changes have been made:

Carlsbad Field Office
OCD Artesia

Intermediate Casing:

The Primary Casing Program has been revised to include 10-5/8" hole size.
A variance is requested to have the option to drill 9-7/8" hole size.

14. I hereby certify that the foregoing is true and correct.
Electronic Submission #454078 verified by the BLM Well Information System
For DEVON ENERGY PRODUCTION COMPAN, sent to the Carlsbad
Committed to AFMSS for processing by PRISCILLA PEREZ on 02/11/2019 (19PP1033SE)

Name *(Printed/Typed)* LINDA GOOD	Title REGULATORY SPECIALIST
Signature (Electronic Submission)	Date 02/11/2019

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By LONG VO	Title PETROLEUM ENGINEER	Date 02/23/2019
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)

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

RWP 3-22-19

Additional data for EC transaction #454078 that would not fit on the form

32. Additional remarks, continued

The Primary Casing Design has been revised to include 8-5/8" 32# P110 Tec-Lock Wedge

Intermediate Casing Shoe Depth has been moved to the 3rd Bone Spring Lime at 10,500' TVD

Production Casing:

The Primary casing string will consist of 5-1/2" 20# P110EC VAM-TOP HT and 5-1/2" 20# P-110EC DWC/C-IS PLUS

Intermediate & Production Cement
The cement volumes have been updated according to the changes detailed above.

Attachments

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	DEVON ENERGY PRODUCTION COMPANY LP
LEASE NO.:	NMNM125635
WELL NAME & NO.:	LUSITANO 27-34 FED COM 624H
SURFACE HOLE FOOTAGE:	235'/N & 1934'/E
BOTTOM HOLE FOOTAGE	20'/S & 2310'/E
LOCATION:	SECTION 27, T25S, R31E, NMPM
COUNTY:	EDDY

COA

H2S	○ Yes	● No	
Potash	● None	○ Secretary	○ R-111-P
Cave/Karst Potential	○ Low	● Medium	○ High
Variance	○ None	● Flex Hose	○ Other
Wellhead	○ Conventional	○ Multibowl	● Both
Other	☐ 4 String Area	☐ Capitan Reef	☐ WIPP
Other	☑ Fluid Filled	☑ Cement Squeeze	☐ Pilot Hole
Special Requirements	☐ Water Disposal	☑ COM	☐ Unit

All Previous COAs Still Apply.

A. CASING

Primary Casing Design:

1. The **13-3/8** inch surface casing shall be set at approximately **931 feet** (a minimum of 25 feet into the Rustler Anhydrite and 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 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.

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

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

Option 1 (Single Stage):

- 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.

Option 2:

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

a. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.

b. Second stage above DV tool:

- Cement to surface. If cement does not circulate, contact the appropriate BLM office.
  Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.

❖ In Medium Cave/Karst Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

Operator has proposed to pump down 13-3/8" X 8-5/8" annulus. Operator must run a CBL from TD of the 8-5/8" casing to surface. Submit results to BLM.

Operator is Approved for option to drill change intermediate 1 hole size to 9.875" with connection change to TLW.

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.
  Cement excess is less than 25%, more cement might be required.

Alternate Casing Design:

4. The **13-3/8** inch surface casing shall be set at approximately **931 feet** (a minimum of 25 feet into the Rustler Anhydrite and above the salt) and cemented to the surface.

    e. 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.
    f. 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)
    g. 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.
    h. If cement falls back, remedial cementing will be done prior to drilling out that string.

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

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

Option 1 (Single Stage):

- 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.**

Option 2:

Operator has proposed a DV tool, the depth may be adjusted as long as the cement is changed proportionally. The DV tool may be cancelled if cement circulates to surface on the first stage.

c. First stage to DV tool: Cement to circulate. If cement does not circulate off the DV tool, contact the appropriate BLM office before proceeding with second stage cement job.

d. Second stage above DV tool:

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

Wait on cement (WOC) time for a primary cement job is to include the lead cement slurry due to cave/karst or potash.

- In Medium Cave/Karst Areas if cement does not circulate to surface on the first two casing strings, the cement on the 3rd casing string must come to surface.

Operator has proposed to pump down 13-3/8" X 8-5/8" annulus. Operator must run a CBL from TD of the 8-5/8" casing to surface. Submit results to BLM.

6. 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. **Cement excess is less than 25%, more cement might be required.**

B. 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.

Option 1:

a. 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.

b. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the intermediate casing shoe shall be **10,000 (10M)** psi. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 5000 (5M) psi.**

Option 2:

1. 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. **Variance is approved to use a 5000 (5M) Annular which shall be tested to 5000 (5M) 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 OOGO2.III.A.2.i must be followed.

C. 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.

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)

☒ Chaves and Roosevelt Counties
Call the Roswell Field Office, 2909 West Second St., Roswell NM 88201.
During office hours call (575) 627-0272.
After office hours call (575)

☒ Eddy County
Call the Carlsbad Field Office, 620 East Greene St., Carlsbad, NM 88220, (575) 361-2822

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

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
      - Notify the BLM when moving in and removing the Spudder Rig.
      - 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.
      - BOP/BOPE test to be conducted per Onshore Oil and Gas Order No. 2 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. 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.

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, 2) until cement has been in place at least 24 hours. WOC time will be recorded in the driller's log.

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.

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-P 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 Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. If a variance is approved for a flexible hose to be installed from the BOP to the choke manifold, the following requirements apply: 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:

    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. Whenever any seal subject to test pressure is broken, all the tests in OOGO2.III.A.2.i must be followed.
    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.

5. 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. 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 plug. However, **no tests** shall commence until the cement has had a minimum of 24 hours setup time.

c. The tests shall be done by an independent service company utilizing a test plug not a cup or J-packer. The operator also has the option of utilizing an independent tester to test without a plug (i.e. against the casing) pursuant to Onshore Order 2 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 water basin (8 hours) or potash (24 hours) or 500 pounds compressive strength, whichever is greater, prior to initiating the test (see casing segment as lead cement may be critical item).

d. 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.

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

f. 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.

g. 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.

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

Lusitano 27-34 Fed Com 624H

1. Geologic Formations

TVD of target	11768	Pilot hole depth	N/A
MD at TD:	21904	Deepest expected fresh water:	

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/ Target Zone?	Hazards*
Rustler	903		
Salado	1168		
Base of Salt	4268		
Delaware	4288		
L Brushy Canyon	8013		
Bone Spring	8238		
Leonard 'A'	8353		
Leonard 'B'	8753		
Leonard 'C'	9003		
1st BSPG Sand	9283		
2nd BSPG Lime	9683		
2nd BSPG Sand	9988		
L 2nd BSPG Sand	10308		
3rd BSPG Lime	10373		
3rd BSPG Sand	11173		
Wolfcamp	11638		
Wolfcamp 'Y'	11768		

*H2S, water flows, loss of circulation, abnormal pressures, etc.

2. Casing Program (Primary Design)

Hole Size	Casing Interval		Csg. Size	Wt. (PPF)	Grade	Conn	Min SF Collapse	Min SF Burst	Min SF Tension
	From	To							
17.5"	0	931	13.375"	48	H-40	STC	1.125	1.25	1.6
10.625"	0	10500	8.625"	32	P110EC	Tec-Lock Wedge	1.125	1.25	1.6
7.875"	0	TD	5.5"	20 ~~17~~	P110	VAMTOP HT x DWC/CIS Plus	1.125	1.25	1.6
				BLM Minimum Safety Factor			1.125	1.00	1.6 Dry 1.8 Wet

TD = 10500

D = 11768
D = 21904.7

VAMTOP - Surface to KOP
DWC/C - KOP to TD
KOP = 11206

- All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h Must have table for contingency casing
- Rustler top will be validated via drilling parameters (i.e. reduction in ROP) and surface casing setting depth revised accordingly if needed.
- Int 1 casing shoe will be selected based on drilling data / gamma, setting depth with be revised accordingly if needed.

- ~~Option to drill change intermediate I hole size to 9.875, (8.625" connection will change from STC to TLW)~~
- ~~Option to run 8.625" TLW connection for intermediate I~~
- A variance is requested to wave the centralizer requirement for the Intermediate casing and production casing.
- Variance is requested for collapse rating on intermediate casing. Operator will keep pipe full while running casing. No losses are expected in subsequent hole section.

Casing Program (Alternate Design)

Hole Size	Casing Interval From	Casing Interval To	Csg. Size	Wt. (PPF)	Grade	Conn	Min SF Collapse	Min SF Burst	Min SF Tension
17.5"	0	931	13.375"	48	H-40	STC	1.125	1.25	1.6
10.625"	0	5000	8.625"	32	P110EC	BTC	1.125	1.25	1.6
9.875"	5000	12106				VAM FJL			
7.875"	0	TD	5.5"	20	P110	BTC	1.125	1.25	1.6
				BLM Minimum Safety Factor			1.125	1.00	1.6 Dry 1.8 Wet

- All casing strings will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.h Must have table for contingency casing
- Rustler top will be validated via drilling parameters (i.e. reduction in ROP) and surface casing setting depth revised accordingly if needed.
- Int 1 casing shoe will be selected based on drilling data / gamma, setting depth with be revised accordingly if needed.
- A variance is requested to wave the centralizer requirement for the Intermediate casing and production casing.
- Variance is requested for collapse rating on intermediate casing. Operator will keep pipe full while running casing. No losses are expected in subsequent hole section.

	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Does casing meet API specifications? If no, attach casing specification sheet.	Y
Is premium or uncommon casing planned? If yes attach casing specification sheet.	N
Does the above casing design meet or exceed BLM's minimum standards? If not provide justification (loading assumptions, casing design criteria).	Y
Will the intermediate pipe be kept at a minimum 1/3 fluid filled to avoid approaching the collapse pressure rating of the casing?	Y
Is well located within Capitan Reef?	N
If yes, does production casing cement tie back a minimum of 50' above the Reef?	
Is well within the designated 4 string boundary.	
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3rd string cement tied back 500' into previous casing?	
Is well located in R-111-P and SOPA?	N

If yes, are the first three strings cemented to surface?	
Is 2nd string set 100' to 600' below the base of salt?	
Is well located in high Cave/Karst?	N
If yes, are there two strings cemented to surface?	
(For 2 string wells) If yes, is there a contingency casing if lost circulation occurs?	
Is well located in critical Cave/Karst?	N
If yes, are there three strings cemented to surface?	

3. Cementing Program (Primary Design)

Casing	# Sks	TOC	Wt. (lb/gal)	Yld (ft3/sack)	Slurry Description
Surface	752	Surf	13.2	1.33	Lead: Class C Cement + additives
Int 1	1152	Surf	9	1.85	Lead: Class C Cement + additives
	831	4000' above shoe	13.2	1.33	Tail: Class H / C + additives
Int 1 Two Stage w DV @ ~4500	590	Surf	9	1.85	1st stage Lead: Class C Cement + additives
	55	500' above shoe	13.2	1.33	1st stage Tail: Class H / C + additives
	600	Surf	9	1.85	2st stage Lead: Class C Cement + additives
	55	500' above DV	13.2	1.33	2st stage Tail: Class H / C + additives
Int 1 Intermediate Squeeze	As Needed	Surf	13.2	1.33	Squeeze Lead: Class C Cement + additives
	1152	Surf	9	1.85	Lead: Class C Cement + additives
	831	4000' above shoe	13.2	1.33	Tail: Class H / C + additives
Production	860	500' tieback	13.2	1.33	Lead: Class H / C + additives

If a DV tool is ran the depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. Slurry weights will be adjusted based on estimated fracture gradient of the formation. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. If cement is not returned to surface during the primary cement job on the surface casing string, a planned top job will be conducted immediately after completion of the primary job.

Casing String	% Excess
Surface	50%
Intermediate 1	30%
Intermediate 1 (Two Stage)	25%
Prod	10%

Cementing Program (Alternate Design)

Casing	# Sks	TOC	Wt. (lb/gal)	Yld (ft3/sack)	Slurry Description
Surface	770	Surf	13.2	1.33	Lead: Class C Cement + additives
Int 1	1291	Surf	9	3.31	Lead: Class C Cement + additives
	834	4000' above shoe	13.2	1.33	Tail: Class H / C + additives
Int 1 Two Stage w DV @ ~4500	650	Surf	9	3.31	1st stage Lead: Class C Cement + additives
	55	500' above shoe	13.2	1.33	1st stage Tail: Class H / C + additives
	625	Surf	9	3.31	2st stage Lead: Class C Cement + additives
	55	500' above DV	13.2	1.33	2st stage Tail: Class H / C + additives
Int 1 Intermediate Squeeze	As Needed	Surf	13.2	1.33	Squeeze Lead: Class C Cement + additives
	1291	Surf	9	3.31	Lead: Class C Cement + additives
	834	4000' above shoe	13.2	1.33	Tail: Class H / C + additives
Production	1219	500' tieback	13.2	1.33	Lead: Class H / C + additives

If a DV tool is ran the depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. Slurry weights will be adjusted based on estimated fracture gradient of the formation. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. If cement is not returned to surface during the primary cement job on the surface casing string, a planned top job will be conducted immediately after completion of the primary job.

Casing String	% Excess
Surface	50%
Intermediate 1	30%
Intermediate 1 (Two Stage)	25%
Prod	10%

4. Pressure Control Equipment (Three String Design)

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type	✓	Tested to:
Int 1	13-5/8"	5M	Annular	X	50% of rated working pressure
			Blind Ram	X	5M
			Pipe Ram		
			Double Ram	X	
			Other*		
Production	13-5/8"	10M	Annular (5M)	X	100% of rated working pressure
			Blind Ram	X	10M
			Pipe Ram		
			Double Ram	X	
			Other *		
			Annular		
			Blind Ram		
			Pipe Ram		
			Double Ram		
			Other *		

N	A variance is requested for the use of a diverter on the surface casing. See attached for schematic.
Y	**A variance is requested to run a 5M annular on a 10M system.**

5. Mud Program (3 String Design)

Depth		Type	Weight (ppg)	Vis	Water Loss
From	To				
0	931'	FW Gel	8.5 - 9	28-34	N/C
908'	12,106	DBE / Cut Brine	9 - 10	28-34	N/C
12106	TD	OBM	10-10.5	28-34	N/C

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at all times.

What will be used to monitor the loss or gain of fluid?	PVT/Pason/Visual Monitoring

6. Logging and Testing Procedures

Logging, Coring and Testing.	
X	Will run GR/CNL fromTD to surface (horizontal well – vertical portion of hole). Stated logs run will be in the Completion Report and submitted to the BLM.
	No Logs are planned based on well control or offset log information.
	Drill stem test? If yes, explain
	Coring? If yes, explain

Additional logs planned		Interval
	Resistivity	Int. shoe to KOP
	Density	Int. shoe to KOP
X	CBL	Production casing
X	Mud log	Intermediate shoe to TD
	PEX	

7. Drilling Conditions

Condition	Specify what type and where?
BH Pressure at deepest TVD	6425 psi
Abnormal Temperature	No

Mitigation measure for abnormal conditions. Describe. Lost circulation material/sweeps/mud scavengers.

Hydrogen Sulfide (H2S) monitors will be installed prior to drilling out the surface shoe. If H2S is detected in concentrations greater than 100 ppm, the operator will comply with the provisions of Onshore Oil and Gas Order #6. If Hydrogen Sulfide is encountered, measured values and formations will be provided to the BLM.	
N	H2S is present
Y	H2S Plan attached

8. Other facets of operation

Is this a walking operation? Potentially

1. If operator elects, drilling rig will batch drill the surface holes and run/cement surface casing; walking the rig to next wells on the pad.
2. The drilling rig will then batch drill the intermediate sections and run/cement intermediate casing; the wellbore will be isolated with a blind flange and pressure gauge installed for monitoring the well before walking to the next well.
3. The drilling rig will then batch drill the production hole sections on the wells with OBM, run/cement production casing, and install TA caps or tubing heads for completions.

NOTE: During batch operations the drilling rig will be moved from well to well however, it will not be removed from the pad until all wells have production casing run/cemented.

Will be pre-setting casing? Potentially

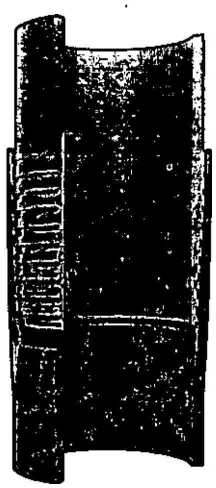
1. Spudder rig will move in and drill surface hole.
    a. Rig will utilize fresh water based mud to drill surface hole to TD. Solids control will be handled entirely on a closed loop basis.
2. After drilling the surface hole section, the spudder rig will run casing and cement following all of the applicable rules and regulations (OnShore Order 2, all COAs and NMOCD regulations).
3. The wellhead will be installed and tested once the surface casing is cut off and the WOC time has been reached.
4. A blind flange with the same pressure rating as the wellhead will be installed to seal the wellbore. Pressure will be monitored with a pressure gauge installed on the wellhead.
5. Spudder rig operations is expected to take 4-5 days per well on a multi well pad.

6. The NMOCD will be contacted and notified 24 hours prior to commencing spudder rig operations.
7. Drilling operations will be performed with the drilling rig. At that time an approved BOP stack will be nippled up and tested on the wellhead before drilling operations commences on each well.
    a. The NMOCD will be contacted / notified 24 hours before the drilling rig moves back on to the pad with the pre-set surface casing.

Attachments
_x_ Directional Plan
___ Other, describe

TEC-LOCK WEDGE

8.625" 32.00 LB/FT (.352" Wall)
BORUSAN MANNESMANNP110 HSCY



Pipe Body Data

Nominal OD:	8.625	in
Nominal Wall:	.352	in
Nominal Weight:	32.00	lb/ft
Plain End Weight:	31.13	lb/ft
Material Grade:	P110 HSCY	
Mill/Specification:	BORUSAN MANNESMANN	
Yield Strength:	125,000	psi
Tensile Strength:	125,000	psi
Nominal ID:	7.921	in
API Drift Diameter:	7.796	in
Special Drift Diameter:	7.875	in
RBW:	87.5 %	
Body Yield:	1,144,000	lbf
Burst:	8,930	psi
Collapse:	4,230	psi

Connection Data

Standard OD:	9.000	in
Pin Bored ID:	7.921	in
Critical Section Area:	8.61433	in^2
Tensile Efficiency:	94.2 %	
Compressive Efficiency:	100.0 %	
Longitudinal Yield Strength:	1,077,000	lbf
Compressive Limit:	1,144,000	lbf
Internal Pressure Rating:	8,930	psi
External Pressure Rating:	4,230	psi
Maximum Bend:	62.6	°/100

Operational Data

Minimum Makeup Torque:	29,900	ft*lbf
Optimum Makeup Torque:	37,375	ft*lbf
Maximum Makeup Torque:	80,900	ft*lbf
Minimum Yield:	89,900	ft*lbf
Makeup Loss:	5.97	in

Notes

Operational Torque is equivalent to the Maximum Make-Up Torque.

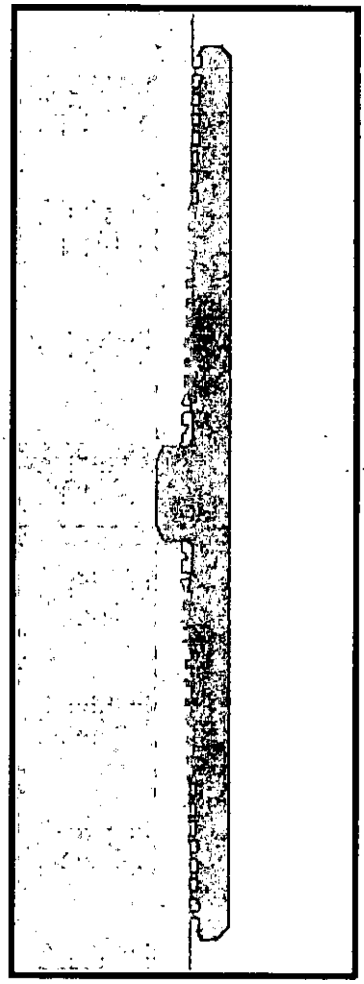
HUNTING

Technical Specifications

Connection Type:	Size(O.D.):	Weight (Wall):	Grade:
DWC/C-IS PLUS Casing standard	5-1/2 in	20.00 lb/ft (0.361 in)	VST P110 EC

VAM USA
4424 W. Sam Houston Pkwy. Suite 150
Houston, TX 77041
Phone: 713-479-3200
Fax: 713-479-3234
E-mail: VAMUSAsales@vam-usa.com

	Material
VST P110 EC	Grade
125,000	Minimum Yield Strength (psi)
135,000	Minimum Ultimate Strength (psi)
	Pipe Dimensions
5.500	Nominal Pipe Body O.D. (in)
4.778	Nominal Pipe Body I.D.(in)
0.361	Nominal Wall Thickness (in)
20.00	Nominal Weight (lbs/ft)
19.83	Plain End Weight (lbs/ft)
5.828	Nominal Pipe Body Area (sq in)
	Pipe Body Performance Properties
729,000	Minimum Pipe Body Yield Strength (lbs)
12,090	Minimum Collapse Pressure (psi)
14,360	Minimum Internal Yield Pressure (psi)
13,100	Hydrostatic Test Pressure (psi)
	Connection Dimensions
6.300	Connection O.D. (in)
4.778	Connection I.D. (in)
4.653	Connection Drift Diameter (in)
4.13	Make-up Loss (in)
5.828	Critical Area (sq in)
100.0	Joint Efficiency (%)
	Connection Performance Properties
729,000	Joint Strength (lbs)
26,040	Reference String Length (ft) 1.4 Design Factor
728,000	API Joint Strength (lbs)
729,000	Compression Rating (lbs)
12,090	API Collapse Pressure Rating (psi)
14,360	API Internal Pressure Resistance (psi)
104.2	Maximum Uniaxial Bend Rating [degrees/100 ft]
	Appoximated Field End Torque Values
16,600	Minimum Final Torque (ft-lbs)
19,100	Maximum Final Torque (ft-lbs)
21,600	Connection Yield Torque (ft-lbs)

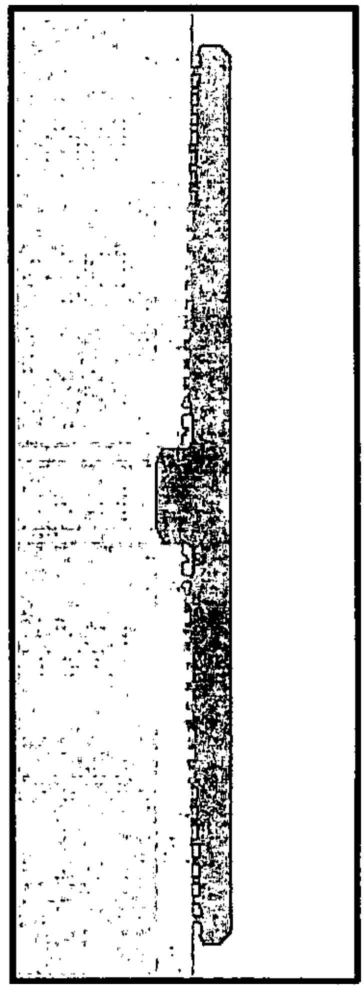


For detailed information on performance properties, refer to DWC Connection Data Notes on following page(s).

2/6/2015

DWC Connection Data Notes:

1. DWC connections are available with a seal ring (SR) option.
2. All standard DWC/C connections are interchangeable for a give pipe OD. DWC connections are interchangeable with DWC/C-SR connections of the same OD and wall.
3. Connection performance properties are based on nominal pipe body and connection dimensions.
4. DWC connection internal and external pressure resistance is calculated using the API rating for buttress connections. API Internal pressure resistance is calculated from formulas 31, 32, and 35 in the API Bulletin 5C3.
5. DWC joint strength is the minimum pipe body yield strength multiplied by the connection critical area.
6. API joint strength is for reference only. It is calculated from formulas 42 and 43 in the API Bulletin 5C3.
7. Bending efficiency is equal to the compression efficiency.
8. The torque values listed are recommended. The actual torque required may be affected by field conditions such as temperature, thread compound, speed of make-up, weather conditions, etc.
9. Connection yield torque is not to be exceeded.
10. Reference string length is calculated by dividing the joint strength by both the nominal weight in air and a design factor (DF) of 1.4. These values are offered for reference only and do not include load factors such as bending, buoyancy, temperature, load dynamics, etc.
11. DWC connections will accommodate API standard drift diameters.



Connection specifications within the control of VAM USA were correct as of the date printed. Specifications are subject to change without notice. Certain connection specifications are dependent on the mechanical properties of the pipe. Mechanical properties of mill proprietary pipe grades were obtained from mill publications and are subject to change. Properties of mill proprietary grades should be confirmed with the mill. Users are advised to obtain current connection specifications and verify pipe mechanical properties for each application.

2/6/2015

Issued on: 31 Mar. 2014

VAM® TOP HT
Connection Data Sheet

OD	Weight	Wall Th.	Grade	API Drift	Connection
5 1/2 in.	20.00 lb/ft	0.361 in.	P110 EC	4.653 in.	VAM® TOP HT

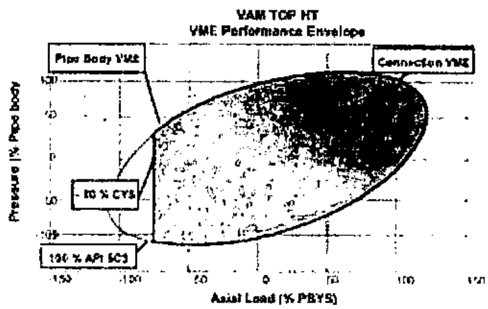
PIPE PROPERTIES	
Nominal OD	5.500 in.
Nominal ID	4.778 in.
Nominal Cross Section Area	5.828 sqin.
Grade Type	High Yield
Min. Yield Strength	125 ksi
Max. Yield Strength	140 ksi
Min. Ultimate Tensile Strength	135 ksi

CONNECTION PROPERTIES	
Connection Type	Premium T&C
Connection OD (nom)	6.071 in.
Connection ID (nom)	4.715 in.
Make-up Loss	4.382 in.
Coupling Length	10.748 in.
Critical Cross Section	5.828 sqin.
Tension Efficiency	100 % of pipe
Compression Efficiency	80 % of pipe
Internal Pressure Efficiency	100 % of pipe
External Pressure Efficiency	100 % of pipe

CONNECTION PERFORMANCES	
Tensile Yield Strength	729 klb
Compression Resistance	583 klb
Internal Yield Pressure	14360 psi
External pressure resistance	12090 psi
Max. bending with sealability	30 °/100 ft
Max. Load on Coupling Face	388 klb

TORQUE VALUES	
Min. Make-up torque	10850 ft.lb
Opti. Make-up torque	11950 ft.lb
Max. Make-up torque	13050 ft.lb
Field Liner Max	15900 ft.lb
Mill and Licensees Torque - Min	15900 ft.lb
Mill and Licensees Torque - Max	17500 ft.lb

VAM® TOP HT (High Torque) is a T&C connection based on the main features of the VAM® TOP connection.
This connection provides reinforced torque capability for liners and where High Torque is anticipated due to string rotation during running operations (torque rotating liner while running, rotating casing when cementing).It has been tested as per ISO13679 CAL IV requirements.
VAM® TOP HT is interchangeable with VAM® TOP product line with the exception of 4 1/2" size.



Connection Yield Strength = 100% Pipe Body Yield Strength for standard design

Do you need help on this product? - Remember no one knows VAM® like VAM

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Over 140 VAM® Specialists available worldwide 24/7 for Rig Site Assistance

VAM USA