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.

Carlsbad Field Office
OCD Hobbs

HOBBS OCD
MAR 19 2018
RECEIVED

5. Lease Serial No.
NMNM117126

6. If Indian, Allottee or Tribe Name

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.
USHANKA FEDERAL COM 23H

2. Name of Operator
COG OPERATING LLC
Contact: MAYTE REYES
E-Mail: mreyes1@concho.com

9. API Well No.
30-025-44505

3a. Address
ONE CONCHO CENTER 600 W ILLINOIS AVENUE
MIDLAND, TX 79701-4287

3b. Phone No. (include area code)
Ph: 575.748.6945

10. Field and Pool or Exploratory Area
WILDCAT;WOLFCAMP

4. Location of Well *(Footage, Sec., T., R., M., or Survey Description)*
Sec 1 T26S R35E NWNE 210FNL 1650FEL
32.078995 N Lat, 103.318047 W Lon

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 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.

COG Operating LLC respectfully requests approval for the following drilling changes to the above referenced APD.

Surface
Drill 14 ?? hole to 930?
Casing will remain unchanged from approved APD
Cement in 1 stage
Lead: 500 sx of 13.5 ppg Class C + 4% gel
Tail: 250 sx of 14.8 ppg Class C + 1% CaCl2

SEE ATTACHED FOR CONDITIONS OF APPROVAL

Intermediate
Drill 9 7/8? hole to 11,600?

14. I hereby certify that the foregoing is true and correct.
Electronic Submission #407656 verified by the BLM Well Information System
For COG OPERATING LLC, sent to the Hobbs
Committed to AFMSS for processing by MUSTAFA HAQUE on 03/15/2018 (18MH0045SE)

Name *(Printed/Typed)* MAYTE REYES — Title REGULATORY ANALYST

Signature (Electronic Submission) — Date 03/14/2018

THIS SPACE FOR FEDERAL OR STATE OFFICE USE

Approved By MUSTAFA HAQUE — Title PETROLEUM ENGINEER — Date 03/15/2018

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 #407656 that would not fit on the form

32. Additional remarks, continued

Set 7 5/8? 29.7# L80HCN BTC casing @ 11,600? (Spec Sheet Attached)
Casing will be kept at least 1/3 full while running casing to mitigate collapse.
Cemented in two stages with ECP/DVT @ 4,970?
Stage 1
Lead: 725 sx of 11.0 ppg Halliburton Neocem Blend (2.81 cuft/sx, 17.4 gal/sx)
Tail: 300 sx of 16.4 ppg Class H (1.10 cuft/sx, 6.0 gal/sx)
Stage 2
Lead: 700 sx of 11.0 ppg Halliburton Neocem Blend (2.81 cuft/sx, 17.4 gal/sx)
Tail: 150 sx of 14.8 ppg Class C (1.35 cuft/sx, 6.6 gal/sx)

Attached:
Casing Performance Data Sheet.
6.75 - 5M Variance Well Control Plan.

1. Component and Preventer Compatibility Table

The table below covers drilling and casing of the 10M MASP portion of the well and outlines the tubulars and the compatible preventers in use. Combined with the mud program, the below documents that two barriers to flow can be maintained at all times, independent of the rating of the annular preventer.

Component	OD	Preventer	RWP
Drill pipe	4.5"	Upper 4.5-7" VBR Lower 4.5-7" VBR	10M
HWDP	4.5"		
Jars	4.875" - 5"		
Drill collars and MWD tools	4.75" - 5"		
Mud Motor	4.75"-5.875"		
Production casing	5.5" & 5"		
ALL	0- 13.625"	Annular	5M
Open-hole	-	Blind Rams	10M

VBR = Variable Bore Ram with compatible range listed in chart.

2. Well Control and Shut-In Procedures

Well control procedures are specific to the rig equipment and the operation at the time the kick occurs. Below are minimum tasks prescribed to assure a proper shut-in while drilling, tripping, running casing, pipe out of the hole (open hole), and moving the BHA through the BOPs. The maximum pressure at which well control is transferred from the annular to another compatible ram is 2500 psi.

Drilling:

1. Sound the alarm (alert rig crew)
2. Space out the drill string
3. Shut down pumps and stop the rotary
4. Shut-in the well with the annular with HCR and choke in closed position
5. Confirm the well is shut-in
6. Notify contractor and company representatives
7. Read and record the following data
    - Time of shut-in
    - SIDPP and SICP
    - Pit gain
8. If pressure has increased to or is anticipated to increase to 2500 psi, confirm spacing and close the upper pipe rams.
9. Prepare for well kill operation.

Tripping:

1. Sound alarm (alert rig crew)
2. Stab full opening safety valve and close the valve
3. Space out the drill string
4. Shut-in the well with the annular with HCR and choke in closed position
5. Confirm shut-in
6. Notify contractor and company representatives
7. Read and record the following data:

- Time of shut-in
- SIDPP and SICP
- Pit gain

8. If pressure has increased to or is anticipated to increase to 2500 psi, confirm spacing and close the upper pipe rams.
9. Prepare for well kill operation.

Running Casing

1. Sound alarm (alert rig crew)
2. Stab crossover and valve and close the valve
3. Shut-in the well with annular with HCR and choke in closed position
4. Confirm shut-in
5. Notify contractor and company representatives
6. Read and record the following data
    - Time of shut-in
    - SIDPP and SICP
    - Pit gain
7. If pressure has increased to or is anticipated to increase to 2500 psi, confirm spacing and close the upper pipe rams.
8. Prepare for well kill operation

No Pipe in Hole (Open Hole)

1. At any point when pipe or BHA are not in BOP stack, well will be shut in with blind rams, HCR will be open and choke will be closed. If pressure increase is observed:
2. Sound alarm (alert crew)
3. Confirm shut-in
4. Notify contractor and company representatives
5. Read and record the following data
    - Time of shut-in
    - Time of pressure increase
    - SICP
6. Prepare for well kill operation

Pulling BHA through BOP Stack

1. Prior to pulling last joint/stand of drillpipe through the stack, perform a flow check. If well is flowing:
    a. Sound alarm (alert crew)
    b. Stab full opening safety valve and close the valve
    c. Space out drill string with tooljoint just beneath the upper pipe ram.
    d. Shut-in the well with upper pipe ram with HCR and choke in closed position
    e. Confirm shut-in
    f. Notify contractor and company representatives
    g. Read and record the following data
        - Time of shut-in
        - SIDPP and SICP
        - Pit gain
    h. Prepare for well kill operation.

2. With BHA in the stack:
    a. If possible to pick up high enough, pull BHA clear of the stack
        i. Follow "Open Hole" procedure above
    b. If impossible to pick up high enough to pull BHA clear of the stack:
        i. Stab crossover, make up one joint/stand of drillpipe, and full opening safety valve and close
        ii. Space out drill string with tooljoint just beneath the upper pipe ram.
        iii. Shut-in the well with upper pipe ram with HCR and choke in closed position
        iv. Confirm shut-in
        v. Notify contractor and company representatives
        vi. Read and record the following:
            - Time of shut-in
            - SIDPP and SICP
            - Pit gain
        vii. Prepare for well kill operation.

3. Well Control Drills

Well control drills are specific to the rig equipment, personnel and operation at the time a kick occurs. Each crew will execute one drill weekly relevant to ongoing operations, but will make a reasonable attempt to vary the type of drills. The drills will be recorded in the daily drilling log. Below are minimum tasks for respective well control drills.

<u>Drilling/Pit:</u>

Action	Responsible Party
Initiate Drill • Lift Flow Sensor or Pit Float to indicate a kick • Immediately record start time	Company Representative / Rig Manager
Recognition • Driller and/or Crew recognizes indicator • Driller stop drilling, pick up off bottom and spaces out drill string, stop pumps and rotary • Conduct flow check	Driller
Initiate Action • Sound alarm, notify rig crew that the well is flowing	Company Representative / Rig Manager
Reaction • Driller moves BOP remote and stands by • Crew is at their assigned stations • Time is stopped • Record time and drill type in the Drilling Report	Driller / Crew

Tripping Pit Drills (either in the hole or out of the hole)

Action	Responsible Party
Initiate Drill • Lift Flow Sensor or Pit Float to indicate a kick • Immediately record start time	Company Representative / Rig Manager
Recognition • Driller recognizes indicator • Suspends tripping operations • Conduct Flow Check	Driller
Initiate Action • Sound alarm, notify rig crew that the well is flowing	Company Representative / Rig Manager
Reaction • Position tool joint above rotary and set slips • Stab FOSV and close valve • Driller moves to BOP remote and stands by • Crew is at their assigned stations • Time is stopped • Record time and drill type in the Drilling Report	Driller / Crew

Choke

Action	Responsible Party
• Have designated choke operator on station at the choke panel • Close annular preventer • Pressure annulus up 200-300 psi • Pump slowly to bump the float and obtain SIDPP • At choke operator instruction, slowly bring pumps online to slow pump rate while holding casing pressure constant at the SICP. • Allow time for the well to stabilize. Mark and record circulating drillpipe pressure. • Measure time lag on drillpipe gauge after choke adjustments. • Hold casing pressure constant as pumps are slowed down while choke is closed. • Record time and drill type in the Drilling Report	Company Man / Rig Manager & Rig Crew

BORUSAN MANNESMANN

API 5CT Casing Performance Data Sheet

Manufactured to specifications of API 5CT 9th edition and bears the API monogram.
Designed for enhanced performance through increased collapse resistance.

Grade	L80EHC
	Pipe Body Mechanical Properties
Minimum Yield Strength	80,000 psi
Maximum Yield Strength	95,000 psi
Minimum Tensile Strength	95,000 psi
Maximum Hardness	23.0 HRC
	Sizes
OD	7 5/8 in
Nominal Wall Thickness	0.375 in
Nominal Weight, T&C	29.70 lb/ft
Nominal Weight, PE	29.06 lb/ft
Nominal ID	6.875 in
Standard Drift	6.750 in
Alternate Drift	N/A
	Minimum Performance
Collapse Pressure	6,220 psi
Internal Pressure Yield	7,310 psi
Pipe body Tension Yield	726,000 lbs
Internal pressure leak resistance STC/LTC connections	7,310 psi
Internal pressure leak resistance BTC connections	7,310 psi
	Inspection and Testing
Visual	OD Longitidunal and independent 3rd party SEA
NDT	Independent 3rd party full body EMI after hydrotest Calibration notch sensitivity: 10% of specified wall thickness
	Color code
Pipe ends	One red, one brown and two blue band
Couplings	Red with one brown band

PECOS DISTRICT
DRILLING CONDITIONS OF APPROVAL

OPERATOR'S NAME:	COG Operating
LEASE NO.:	NM117126
WELL NAME & NO.:	23H – Ushanka Federal Com
SURFACE HOLE FOOTAGE:	210'/N & 1650'/E
BOTTOM HOLE FOOTAGE	2440'/S & 1650'/E, sec. 12
LOCATION:	Section 1, T. 26 S., R. 35 E.
COUNTY:	Lea County, New Mexico

Potash	(•) None	( ) Secretary	( ) R-111-P
Cave/Karst Potential	(•) Low	( ) Medium	( ) High
Variance	( ) None	(•) Flex Hose	( ) Other
Wellhead	(•) Conventional	( ) Multibowl	
Other	☐4 String Area	☐Capitan Reef	☐WIPP

All previous COAs still apply except for the following:

A. CASING

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

Operator has proposed DV tool at depth of 4970', 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. If an ECP is used, it is to be set a minimum of 50' below the shoe to provide cement across the shoe. If it cannot be set below the shoe, a CBL shall be run to verify cement coverage.

   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.

B. PRESSURE CONTROL

1. Minimum working pressure of the blowout preventer (BOP) and related equipment (BOPE) required for drilling below the **7 5/8** inch intermediate casing shoe shall be

10,000 (10M) psi. **Variance approved to use a 5M annular. The annular must be tested to full working pressure (5000 psi.)**

MHH 03152018

GENERAL REQUIREMENTS

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.