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NM OIL CONSERVATION
ARTESIA DISTRICT
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Form 3160-3
(March 2012)

FORM APPROVED
OMB No. 1004-0137
Expires October 31, 2014

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5. Lease Serial No. NMNM114992

6. If Indian, Allotee or Tribe Name

1a. Type of work: ☑ DRILL ☐ REENTER

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

(315691)

1b. Type of Well: ☑ Oil Well ☐ Gas Well ☐ Other ☑ Single Zone ☐ Multiple Zone

8. Lease Name and Well No. FIGHTING OKRA 18-19 FED ~~31H~~ 31H

2. Name of Operator Devon Energy Production Company, L.P. (6137)

9. API Well No. 30-025-43267

3a. Address 333 W. Sheridan Ave. Oklahoma City, OK 73102

3b. Phone No. (include area code) 405-552-7848

10. Field and Pool, or Exploratory WC-025 G-06 S263407P;UPR BS (97892) KZ

4. Location of Well (Report location clearly and in accordance with any State requirements.*)
At surface 2310 FNL & 330 FWL, Lot 2 PP: 2360 FSL & 430 FWL
At proposed prod. zone 330 FSL & 330 FWL, Lot 4, 19-26S-34E

11. Sec., T. R. M. or Blk. and Survey or Area 18-26S-34E

14. Distance in miles and direction from nearest town or post office* Approximately 20 miles SW of Jal, NM

12. County or Parish Lea County

13. State NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) See attached map

16. No. of acres in lease 1,283.96 acres

17. Spacing Unit dedicated to this well 243.17 acres

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. See attached map

19. Proposed Depth TVD: 10,374 MD: 18,076'

20. BLM/BIA Bond No. on file CO-1104 & NMB-000801

21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3,357.5' GL

22. Approximate date work will start* 02/29/2016

23. Estimated duration 45 days

24. Attachments To Be Pad Drilled w/ Fighting Okra 18-19 Fed 21H

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, must be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification
6. Such other site specific information and/or plans as may be required by the BLM.

25. Signature | Name (Printed/Typed) David H. Cook | Date 11/11/2015

Title Regulatory Specialist

Approved by (Signature) /s/George MacDonell | Name (Printed/Typed) | Date MAY 13 2016

Title FIELD MANAGER | Office CARLSBAD FIELD OFFICE

Application approval 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.
Conditions of approval, if any, are attached.

APPROVAL FOR TWO YEARS

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.

PM

(Continued on page 2)

*(Instructions on page 2)

Carlsbad Controlled Water Basin

KZ 05/23/16

See attached NMOCD Conditions of Approval

Approval Subject to General Requirements & Special Stipulations Attached

SEE ATTACHED FOR CONDITIONS OF APPROVAL

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Devon Energy, Fighting Okra 18-19 Fed ~~31~~H

1. Geologic Formations

TVD of target	10,374'	Pilot hole depth	N/A
MD at TD:	18,076'	Deepest expected fresh water:	

Basin

Formation	Depth (TVD) from KB	Water/Mineral Bearing/ Target Zone?	Hazards*
Rustler	897	Barren	
Salado	1244	Barren	
Bell Canyon	5295	Barren	
Cherry Canyon	6346	Oil	
Brushy Canyon	8361	Oil	
Bone Spring	9514	Oil	
Leonard Shale (UPR)	9539	Oil	
1st BSPG Sand	10454	Oil	

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

Devon Energy, Fighting Okra 18-19 Fed ~~31~~ 41H

2. Casing Program

See COA

Hole Size	Casing Interval		Csg. Size	Weight (lbs)	Grade	Conn.	SF Collapse	SF Burst	SF Tension
	From	To							
17.5"	0	930'	13.375"	48	H-40	STC	1.73	3.38	2.32
12.25"	0	4,000'	9.625"	40	J-55	BTC	1.21	1.37	2.23
12.25"	4,000'	~~5,395'~~ 5250'	9.625"	40	HCK-55	BTC	1.33	2.54	4.28
8.75"	0	18,076'	5.5"	17	P-110	BTC	1.49	1.25	2.17
				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

	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

Casing	# Sks	Wt. lb/ gal	H_2O gal/sk	Yld ft3/ sack	500# Comp. Strength (hours)	Slurry Description
Surf.	1010	14.8	6.32	1.33	7	Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake
Inter.	1220	12.9	9.81	1.85	17	Lead: (65:35) Class C Cement: Poz (Fly Ash): 6% BWOC Bentonite + 5% BWOW Sodium Chloride + 0.125 lbs/sack Poly-E-Flake
	430	14.8	6.32	1.33	6	Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake
5.5" Prod. Two Stage	710	12.5	10.86	1.96	30	1st Stage Lead: (65:35) Class H Cement: Poz (Fly Ash) + 6% BWOC Bentonite + 0.25% BWOC HR-601 + 0.125 lbs/sack Poly-E-Flake
	2170	14.5	5.31	1.2	25	1st Stage Tail: (50:50) Class H Cement: Poz (Fly Ash) + 0.5% bwoc HALAD-344 + 0.4% bwoc CFR-3 + 0.2% BWOC HR-601 + 2% bwoc Bentonite
	DV Tool = 5445'					
See COA	20	11	14.81	2.55	22	2nd Stage Lead: Tuned Light® Cement + 0.125 lb/sk Pol-E-Flake
	50	14.8	6.32	1.33	6	2nd Stage Tail: Class C Cement + 0.125 lbs/sack Poly-E-Flake

DV tool depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. Lab reports with the 500 psi compressive strength time for the cement will be onsite for review.

Casing String	TOC	% Excess
Surface	0'	100%
Intermediate	0'	75%
5.5" Production Two Stage	1st Stage = 5445' / 2nd Stage = ~~5195'~~ 5050'	25%

See COA

4. Pressure Control Equipment

N	A variance is requested for the use of a diverter on the surface casing. See attached for schematic.

BOP installed and tested before drilling which hole?	Size?	Min. Required WP	Type	✓	Tested to:
12-1/4"	13-5/8"	3M	Annular	x	50% of working pressure
			Blind Ram		3M
			Pipe Ram		
			Double Ram	x	
			Other*		
8-3/4"	13-5/8"	3M	Annular	x	50% testing pressure
			Blind Ram		3M
			Pipe Ram		
			Double Ram	x	
			Other *		

*Specify if additional ram is utilized.

BOP/BOPE will be tested by an independent service company to 250 psi low and the high pressure indicated above per Onshore Order 2 requirements. The System may be upgraded to a higher pressure but still tested to the working pressure listed in the table above. If the system is upgraded all the components installed will be functional and tested.

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold. See attached schematics.

Y	Formation integrity test will be performed per Onshore Order #2. On Exploratory wells or 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. Will be tested in accordance with Onshore Oil and Gas Order #2 III.B.1.i.
Y	A variance is requested for the use of a flexible choke line from the BOP to Choke Manifold. See attached for specs and hydrostatic test chart.

See COA

<table>
<tr><td></td><td>Y</td><td>Are anchors required by manufacturer?</td></tr>
<tr><td>Y</td><td colspan="2">
A multibowl wellhead is being used. The BOP will be tested per Onshore Order #2 after installation on the surface casing which will cover testing requirements for a maximum of 30 days. If any seal subject to test pressure is broken the system must be tested.
Devon proposes using 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 3000 (3M) psi.

Wellhead will be installed by vendor representatives.
If the welding is performed by a third party, the vendor representative will monitor the temperature to verify that it does not exceed the maximum temperature of the seal.
Vendor representative will install the test plug for the initial BOP test.
Vendor will install a solid steel body pack-off to completely isolate the lower head after cementing intermediate casing. After installation of the pack-off, the pack-off and the lower flange will be tested to 3M, as shown on the attached schematic. Everything above the pack-off will not have been altered whatsoever from the initial nipple up. Therefore the BOP components will not be retested at that time.
If the cement does not circulate and one inch operations would have been possible with a standard wellhead, the well head will be cut and top out operations will be conducted.
Devon will pressure test all seals above and below the mandrel (but still above the casing) to full working pressure rating.
Devon will test the casing to 0.22 psi/ft or 1500 psi, whichever is greater, as per Onshore Order #2.

After running the 13-3/8" surface casing, a 13-5/8" BOP/BOPE system with a minimum rating of 3M will be installed on the wellhead system and will undergo a 250 psi low pressure test followed by a 3,000 psi high pressure test. The 3,000 psi high and 250 psi low test will cover testing requirements a maximum of 30 days, as per Onshore Order #2. If the well is not complete within 30 days of this BOP test, another full BOP test will be conducted, as per Onshore Order #2.
After running the 9-5/8' intermediate casing with a mandrel hanger, the 13-5/8" BOP/BOPE system with a minimum rating of 3M will already be installed on the wellhead.
The pipe rams will be operated and checked each 24 hour period and each time the drill pipe is out of the hole. These tests will be logged in the daily driller's log. A 2" kill line and 3" choke line will be incorporated into the drilling spool below the ram BOP. In addition to the rams and annular preventer, additional BOP accessories include a kelly cock, floor safety valve, choke lines, and choke manifold rated at 3,000 psi WP.
Devon requests a variance to use a flexible line with flanged ends between the BOP and the choke manifold (choke line). The line will be kept as straight as possible with minimal turns.
</td></tr>
</table>

See COA

	See attached schematic.

5. Mud Program

See COA

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From	To				
0	930'	FW Gel	8.6-8.8	28-34	N/C
930'	~~5,395'~~ 5250'	Saturated Brine	10.0-10.2	28-34	N/C
~~5,395'~~	18,076'	Cut Brine	8.5-9.3	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	5,016 psi
Abnormal Temperature	No

Mitigation measure for abnormal conditions: 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? No.
Will be pre-setting casing? No.

Attachments
_x_ Directional Plan
___ Other, describe