

OCD Hobbs HOBBS OCD

16-915

MAY 09 2016

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

RECEIVED

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

5a. Type of work: <input checked="" type="checkbox"/> DRILL <input type="checkbox"/> REENTER		5. Lease Serial No. NMLC-0061842	
5b. Type of Well: <input checked="" type="checkbox"/> Oil Well <input type="checkbox"/> Gas Well <input type="checkbox"/> Other <input checked="" type="checkbox"/> Single Zone <input type="checkbox"/> Multiple Zone		6. If Indian, Allottee or Tribe Name N/A	
2. Name of Operator COG Operating LLC (229137)		7. If Unit or CA Agreement, Name and No. N/A	
3a. Address One Concho Center, 600 W. Illinois Ave Midland, TX 79701		8. Lease Name and Well No. (40481) FLAT HEAD FEDERAL COM #17H	
3b. Phone No. (include area code) 432-685-4384		9. API Well No. 30-025- 43224	
4. Location of Well (Report location clearly and in accordance with any State requirements.) At surface SHL: 1190' FNL & 1160' FEL, Unit A, Sec 14 At proposed prod. zone BHL: 330' FNL & 990' FEL, Unit A, Sec 11		10. Field and Pool, or Exploratory Maljamar; Yeso, West 44500' KE	
14. Distance in miles and direction from nearest town or post office* 2 miles SE from Maljamar, NM		11. Sec., T. R. M. or Blk. and Survey or Area Sec 11 & 14 T17S R32E	
15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) 1160'		12. County or Parish LEA	
16. No. of acres in lease 320		13. State NM	
17. Spacing Unit dedicated to this well 200		UNORTHODOX LOCATION	
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 519.3'		19. Proposed Depth TVD: 5950' MD: 11907' EOC: 5950' TVD	
20. BLM/BIA Bond No. on file NMB000740; NMB000215		21. Elevations (Show whether DF, KDB, RT, GL, etc.) 4098' GL	
22. Approximate date work will start* 09/28/2016		23. Estimated duration 15 Days	

24. Attachments

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. | 4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above). |
| 2. A Drilling Plan. | 5. Operator certification |
| 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). | 6. Such other site specific information and/or plans as may be required by the BLM. |

25. Signature 	Name (Printed/Typed) Robyn M. Odorn	Date 03/04/2016
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Title Regulatory Analyst		
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Approved by (Signature) /s/George MacDonell	Name (Printed/Typed)	Date MAY - 4 2016
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Title FIELD MANAGER	Office CARLSBAD FIELD OFFICE
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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.

(Continued on page 2)

Roswell Controlled Water Basin

Ke
09/11/16
PM

See attached NMOCD
Conditions of Approval

SEE ATTACHED FOR
CONDITIONS OF APPROVAL

Approval Subject to General Requirements
& Special Stipulations Attached

MAY 12 2016

**COG Operating LLC
Flat Head Federal Com #17H**

1. Geologic Formations

TVD of target	5950'	Pilot hole depth	NA
MD at TD:	11592'	Deepest expected fresh water:	132'

Back Reef

Formation	Depth (TVD) from KB	Water/Mineral Bearing/Target Zone?	Hazards*
Quaternary Fill	Surface	Fresh Water	
Rustler	1060'	Brackish Water	
Top of Salt	1250'	Salt	
Tansill	2290'	Barren	
Yates	2380'	Oil/Gas	
Queen	3350'	Oil/Gas	
Grayburg	3810'	Oil/Gas	
San Andres	4110'	Oil/Gas	
Glorieta	5580'	Oil/Gas	
Paddock	5640'	Target	
Blinebry	6150'	Will not penetrate	

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

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	1100' 1140'	13.375"	54.5	J55	STC	2.16	5.07	9.01
12.25"	0	2320' 2420'	9.625"	40	J55	LTC	2.28	1.19	5.95
8.75"	0	5379'	7.0"	29	L80	LTC	3.24	1.33	2.07
8.75"	5379'	6688'	5.5"	17	L80	LTC	2.61	1.26	3.09
7.875"	6688'	11592'	5.5"	17	L80	LTC	2.61	1.33	6.17
BLM Minimum Safety Factor							1.125	1	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 BLM standard formulas where used on all SF calculations

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	Y or N
Is casing new? If used, attach certification as required in Onshore Order #1	Y
Is casing API approved? 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 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.	N
Is well located in SOPA but not in R-111-P?	N
If yes, are the first 2 strings cemented to surface and 3 rd 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 2 nd 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 *See COA*

Casing	# Sks	Wt. lb/gal	Yld ft ³ /sack	H ₂ O gal/sk	500# Comp. Strength h (hours)	Slurry Description
Surf.	250	13.5	1.75	9.2	13	Lead: Class C + 4.0% Bentonite + 2% Cacl2 + .25 pps Cello flake
	250	14.8	1.32	6.3	6	Tail: Class C + 2% Cacl2 + .25 pps Celloflake
Inter.	325	11.8	2.45	14.4	72	1 st stage Lead: 50:50:10 C: Poz:Gel w/ 5% Salt + 5 pps Lcm + 0.25 pps Cello flake
	200	14.8	1.32	6.3	6	1 st stage Tail: Class C w/ 2% Cacl2
	IF DV Tool +/- 1195'					
	150	11.8	2.45	14.4	72	1 st stage Lead: 50:50:10 C: Poz:Gel w/ 5% Salt + 5 pps Lcm + 0.25 pps Cello flake
	200	14.8	1.32	6.3	6	1 st stage Tail: Class C w/ 2% Cacl2
	225	11.8	2.45	14.4	72	2nd stage Lead: 50:50:10 C: Poz:Gel w/ 5% Salt + 5 pps Lcm + 0.25 pps Cello flake

Extremely low Cement See COA

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Prod.	600	12.5	2.01	11.4	22	1st stage Lead: 35:65:6 C:Poz Gel w/5% salt + 5 pps LCM + 0.2% SMS + 1% FL-25 + 1% Ba-58+0.3% FL-52A + 0.125 pps CF
	1200	14	1.37	6.4	10	1st stage Tail: 50:50:2 C:Pox Gel w/5% salt+3 pps LCM + 0.6% SMS + 1% FL-25 +1% BA-58+ 0.125 pps CF
	DV/ECP Tool +/- 4155'					
	425	12.5	2.01	11.4	22	2 nd Stage Lead: 35:65;6 C:Poz Gel w/5% salt+5 pps LCM+0.2% SMS + 1% FL-25+1% BA-58+0.3% FL-52A+ 0.125 pps CF
	150	16.8	.99	4.8	6	2 nd Stage Tail: Class"C" w/0.3% R-3 + 1.5% CD-32
	200	12.5	2.01	11.4	22	1 st stage Lead: 35:65:6 C: PozGel w/5% salt + 5 pp LCM + 0.2% SMS + 1% FL-25+ 1% BA-58 + 0.3% FL-52A + 0.125 pps CF
	1200	14	1.37	6.4	10	1 st stage Tail: 50:50:2 C: PozGel w/5% salt + 3 pps LCM + 0.6% SMS + 1% FL-25 + 1% BA-58 + 0.125 pps CF

Casing String	TOC	% Excess
Surface	0'	50%
Intermediate	0'	50%
Production	0'	35%

4. Pressure Control Equipment * See attachment for further details***** *See COA*

No	A variance is requested for the use of a diverter on the surface casing. See attached for schematic.
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BOP installed and tested before drilling which hole?	Size?	Min Required WP	Type	✓	Tested to:
12-1/4"	13-5/8"	2M	Annular	X	2000 psi
			Blind Ram		
			Pipe Ram		
			Double Ram		
			Other*		
8-3/4" & 7 7/8"	13-5/8"	2M	Annular	X	2000 psi
			Blind Ram		
			Pipe Ram		
			Double Ram		
			Other*		

*Specify if additional ram is utilized.

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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.

NA	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.
NA	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.
NA	Are anchors required by manufacturer?
NA	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. <ul style="list-style-type: none"> • Provide description here See attached schematic.

5. Mud Program

Depth		Type	Weight (ppg)	Viscosity	Water Loss
From	To				
0	Surf. shoe	FW Gel	8.6-8.8	28-34	N/C
Surf shoe	Int shoe	Saturated Brine	10.0-10.2	28-34	N/C
Int shoe	TD	FW-Cut Brine	8.5-9.2	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
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6. Logging and Testing Procedures *See COA*

Logging, Coring and Testing.	
X	Will run Cased hole GR/CNL from KOP to surface. Stated logs run will be in the Completion Report and submitted to the BLM.
No	Open hole logs are planned from KOP to Intermediate casing shoe.
No	Drill stem test? If yes, explain
No	Coring? If yes, explain

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

7. Drilling Conditions *See COA*

Condition	Specify what type and where?
BH Pressure at deepest TVD	2618 psi
Abnormal Temperature	No

Mitigation measure for abnormal conditions.

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.

Yes

<input checked="" type="checkbox"/>	H2S is present
<input type="checkbox"/>	H2S Plan attached

8. Other facets of operation

Is this a walking operation? No.
 Will be pre-setting casing? No
 All perforated intervals will be fracture stimulated

Attachments:
 Directional Plan
 Multi-stage Cement details

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Multi-stage Cement details:

Discussion of DV Tool cement options:

9 5/8" DV tool cement option is proposed for approval. This may become necessary if lost circulation occurs while drilling the 12 1/4" intermediate hole. DV tool depth will be based on hole conditions. 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.

7" DV tool cement option is proposed for approval. This may become necessary if water flows in the San Andres are encountered. These water flows normally occur in areas where produced water disposal is happening. This dense cement is used to combat water flows. This cement recipe also has a right angle set time and is mixed a little under saturated so the water flow will be absorbed by cement. DV tool depth will be based on hole conditions. 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.

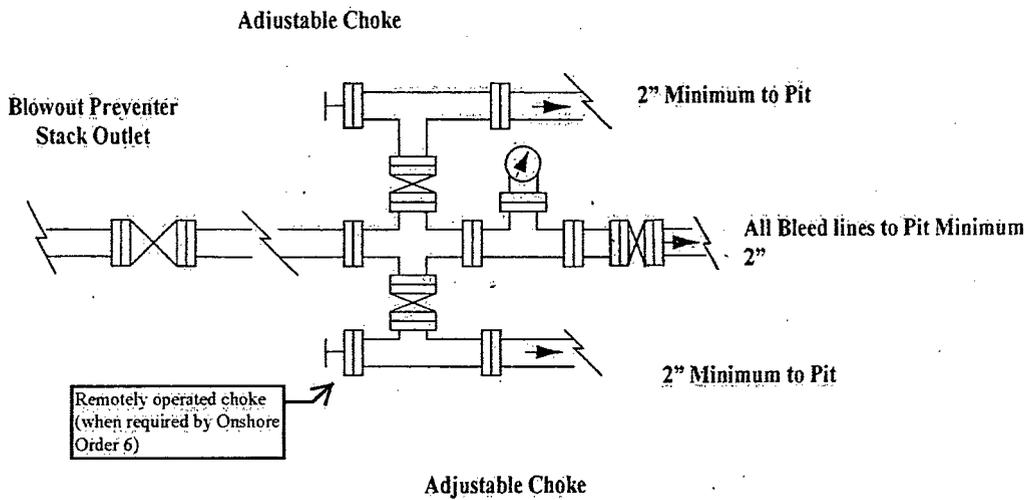
CUB 2/29/16

COG Operating LLC

Exhibit #9

Choke Schematic

Choke Manifold Requirement (2000 psi WP)



NOTES REGARDING THE BLOWOUT PREVENTERS

Master Drilling Plan Eddy County, New Mexico

1. Drilling nipple to be so constructed that it can be removed without use of a welder through rotary table opening, with minimum I.D. equal to preventer bore.
2. Wear ring to be properly installed in head.
3. Blow out preventer and all fittings must be in good condition, 2000 psi WP minimum.
4. All fittings to be flanged.
5. Safety valve must be available on rig floor at all times with proper connections, valve to be full 2000 psi WP minimum.
6. All choke and fill lines to be securely anchored especially ends of choke lines.
7. Equipment through which bit must pass shall be at least as large as the diameter of the casing being drilled through.
8. Kelly cock on Kelly.
9. Extension wrenches and hands wheels to be properly installed.
10. Blow out preventer control to be located as close to driller's position as feasible.
11. Blow out preventer closing equipment to include minimum 40-gallon accumulator, two independent sources of pump power on each closing unit installation all API specifications.

Closed Loop Operation & Maintenance Procedure

All drilling fluid circulated over shaker(s) with cuttings discharged into roll off container.

Fluid and fines below shaker(s) are circulated with transfer pump through centrifuge(s) or solids separator with cuttings and fines discharged into roll off container.

Fluid is continuously re-circulated through equipment with polymer added to aid separation of cutting fines.

Roll off containers are lined and de-watered with fluids re-circulated into system.

Additional tank is used to capture unused drilling fluid or cement returns from casing jobs.

This equipment will be maintained 24 hrs./day by solids control personnel and or rig crews that stay on location.

Cuttings will be hauled to either:

CRI (permit number R9166)

or

GMI (permit number 711-019-001)

dependent upon which rig is available to drill this well.

COG Operating LLC

Closed Loop Equipment Diagram

