HOBBS OCD

SEP 09 2013

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ATS-13-807

Form 3160-3
(March 2012)

OCD Hobbs

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

1a. Type of work: ☑ DRILL ☐ REENTER	5. Lease Serial No. USA LC 058698A
1b. Type of Well: ☐ Oil Well ☐ Gas Well ☑ Other Inj. ☑ Single Zone ☐ Multiple Zone	6. If Indian, Allotee or Tribe Name N/A
2. Name of Operator ConocoPhillips Company <217817>	7. If Unit or CA Agreement, Name and No. ~~101615~~ NM 70987X
3a. Address P.O. Box 51810 Midland, Texas 79710-1810	3b. Phone No. (include area code) 432-688-6913
	8. Lease Name and Well No. MCA Unit 456 <31422>
	9. API Well No. 30-025- 41392
	10. Field and Pool, or Exploratory Maljamar; Grayburg/San Andres <43329>
4. Location of Well (Report location clearly and in accordance with any State requirements.*) At surface UL E, Sec. 26, T17S, R32E; 1780' FNL and 280' FWL. At proposed prod. zone same	11. Sec., T. R. M. or Blk. and Survey or Area Sec. 26, T17S, R32E
14. Distance in miles and direction from nearest town or post office* Approximately 5 miles SE of Maljamar, New Mexico	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) 280'	16. No. of acres in lease 280	17. Spacing Unit dedicated to this well 40
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. approximately 300'	19. Proposed Depth 4400'	20. BLM/BIA Bond No. on file ES 0085
21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3963' GL	22. Approximate date work will start* 11/01/2013	23. Estimated duration 10 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.
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 Susan B. Maunder	Name (Printed/Typed) Susan B. Maunder	Date 5-14-13
Title Senior Regulatory Specialist		
Approved by (Signature) /s/George MacDonell	Name (Printed/Typed)	Date SEP - 4 2013
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.

(Continued on page 2) *(Instructions on page 2)

Roswell Controlled Water Basin

KZ 09/10/13

Approval Subject to General Requirements & Special Stipulations Attached

OIL CONSERVATION DIVISION

CONDITION OF APPROVAL - Approval for drilling / workover **ONLY - CANNOT INJECT OR DISPOSAL** until the injection/disposal order has been approved by the OCD Santa Fe office.

SEE ATTACHED FOR CONDITIONS OF APPROVAL

PM

SEP 11 2013

Drilling Plan
ConocoPhillips Company
Maljamar; Grayburg-San Andres

MCA Unit #456

Lea County, New Mexico

1. Estimated tops of geological markers and estimated depths to water, oil, or gas formations:

The ranges of depths for the formation tops, thicknesses, and planned Total Depths for all the wells to be drilled under this Master Drilling Plan are presented in the table below.

The datum for these depths is RKB (which is 13' above Ground Level).

Formations	Top Depth FT TVD	Contents
Quaternary	Surface	Fresh Water
Rustler	852	Anhydrite
Salado (top of salt)	1030	Salt
Tansill	2130	Gas, Oil and Water
Yates	2268	Gas, Oil and Water
Seven Rivers	2623	Gas, Oil and Water
Queen	3258	Gas, Oil and Water
Grayburg	3562	Gas, Oil and Water
Grayburg-6	3797	Gas, Oil and Water
San Andres-7	3966	Gas, Oil and Water
San Andres-9	4197	Gas, Oil and Water
Total Depth	4400	200' below deepest estimated perforation

All of the water bearing formations identified above will be protected by setting of the 8-5/8" surface casing 25' – 70' into the Rustler formation and circulating of cement from casing shoe to surface in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

The targeted oil and gas bearing formations identified above will be protected by setting of the 5-1/2" production casing 10' off bottom of TD and circulating of cement from casing shoe to surface in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

See COA

2. Proposed casing program:

Type	Hole Size	Interval MD RKB (ft)		OD	Wt	Gr	Conn	MIY	Col	Jt Str	Safety Factors Calculated per ConocoPhillips Corporate Criteria		
	(in)	From	To	(inches)	(lb/ft)			(psi)	(psi)	(klbs)	Burst DF	Collapse DF	Jt Str DF (Tension) Dry/Buoyant
Cond	20	0	40' – 85' (30' – 75' BGL)	16	0.5" wall	B	Line Pipe	N/A	N/A	N/A	NA	NA	NA
Alt. Cond	20	0	40' – 85' (30' – 75' BGL)	13-3/8	48#	H-40	PE	1730	740	N/A	NA	NA	NA
Surf	12-1/4	0	~~877' – 922'~~ 1000	8-5/8	24#	J-55	STC	2950	1370	244	1.55	3.34	3.52
Prod	7-7/8	0	4345' – 4390'	5-1/2	17#	J-55	LTC	5320	4910	247	2.33	3.73	2.18

The casing will be suitable for H_2S Service. All casing will be new.

The surface and production casing will be set approximately 10' off bottom and we will drill the hole with a 45' range uncertainty for casing set depth to fit the casing string so that the cementing head is positioned at the floor for the cement job.

The production casing will be set 155' to 200' below the deepest estimated perforation to provide rathole for the pumping completion and for the logs to get deep enough to log the interval of interest.

Casing Safety Factors - BLM Criteria:

Type	Depth	Wt	MIY	Col	Jt Str	Drill Fluid	Burst	Collapse	Tensile-Dry	Tens-Bouy
Surface Casing	~~922~~	24	2950	1370	244000	8.5	7.24	3.36	11.0	12.7
Production Casing	4390	17	5320	4910	247000	10	2.33	2.15	3.31	3.91

Casing Safety Factors – Additional ConocoPhillips Criteria:

ConocoPhillips casing design policy establishes Corporate Minimum Design Factors (see table below) and requires that service life load cases be considered and provided for in the casing design.

ConocoPhillips Corporate Criteria for Minimum Design Factors

	Burst	Collapse	Axial
Casing Design Factors	1.15	1.05	1.4

Type	Depth	Wt	MIY	Col	Jt Str	Pipe Yield	MW	Burst	Col	Ten
Conductor	85	65	35000	-	-	432966	-			
Surface Casing (8-5/8" 24# J-55 STC)	922	24	2950	1370	244000	381000	8.5	1.55	3.34	3.52
Production Casing (5-1/2" 17# J-55 LTC)	4390	17	5320	4910	247000	273000	10	2.33	3.73	2.18

Burst – ConocoPhillips Required Load Cases

The maximum internal (burst) load on the Surface Casing occurs when the surface casing is tested to 1500 psi (as per BLM Onshore Order 2 - III. Requirements).
The maximum internal (burst) load on the Production Casing occurs during the fracture stimulation where the maximum allowable working pressure (MAWP) is the pressure that would fit ConocoPhillips Corporate Criteria for Minimum Factors.

Surface Casing Test Pressure = 1500 psi
Surface Rated Working Pressure (BOPE) = 3000 psi
Field SW = 10 ppg
Predicted Pore Pressure at TD (PPTD) = 8.55 ppg
Predicted Frac Gradient at Shoe (CSFG) = 19.23 ppg

Surface Casing Burst Safety Factor = API Burst Rating / Maximum Predicted Surface Pressure (MPSP) 'OR' Maximum Allowable Surface Pressure (MASP)
Production Casing MAWP for the Fracture Stimulation = API Burst Rating / Corporate Minimum Burst Design Factor

Surface Casing Burst Safety Factor:

Case #1: MPSP (MWhyd next section) = 922 x 0.052 x 10 = 479
Case #2: MPSP (Field SW @ Bullhead$_{CSFG}$ + 200 psi) = 922 x 0.052 x 19.23 - 479 + 200 = 643
Case #3: MPSP (Kick Vol @ next section TD) = 4390 x 0.052 x 8.55 - 346.8 - 408 = 1197
Case #4: MPSP (PPTD - GG) = 4390 x 0.052 x 8.55 - 439 = 1513
Case #3 & #4 Limited to MPSP (CSFG + 0.2 ppg) = 922 x 0.052 x (19.23 + 0.2) = 932
MASP (MWhyd + Test Pressure) = 922 x 0.052 x 8.5 + 1500 = 1908
Burst Safety Factor (Max. MPSP or MASP) = 2950 / 1908 = 1.55

Production Casing Burst Safety Factor:

Case #1: MPSP (MWhyd TD) = 4390 x 0.052 x 10 = 2282.8
Case #4: MPSP (PPTD - GG) = 4390 x 0.052 x 8.55 - 439 = 1513
Burst Safety Factor (Max. MPSP) = 5320 / 2283 = 2.33
MAWP for the Fracture Stimulation (Corporate Criteria) = 5320 / 1.15 = 4626

Collapse – ConocoPhillips Required Load Cases

The maximum collapse load on the Surface Casing occurs when cementing to surface, 1/3 evacuation to the next casing setting depth, or deepest depth of exposure (full evacuation).
The maximum collapse load on the Production Casing occurs when cementing to surface, or 1/3 evacuation to the deepest depth of exposure; and therefore, the external pressure profile for the evacuation cases should be equal to the pore pressure of the horizons on the outside of the casing which we assumed to be PPTD.

Surface Casing Collapse Safety Factor = API Collapse Rating / Full Evacuation 'OR' Cement Displacement during Cementing to Surface
Production Casing Collapse Safety Factor = API Collapse Rating / Maximum Predicted Surface Pressure 'OR' Cement Displacement during Cementing to Surface

Cement Displacement Fluid (FW) = 8.34 ppg
Surface Cement Lead = 13.6 ppg
Surface Cement Tail = 14.8 ppg
Top of Surface Tail Cement = 300 ft
Top of Cement = Cement to Surface
Prod Cement Lead = 11.8 ppg
Prod Cement Tail = 14.5 ppg
Top of Prod Tail Cement = 3200 ft

Surface Casing Collapse Safety Factor:

Full Evacuation Diff Pressure = 922 x 0.052 x 8.55 = 410
Cementing Diff Lift Pressure = [(622 x 0.052 x 13.6) + (300 x 0.052 x 14.8) - 400] = 271
Collapse Safety Factor = 1370 / 410 = 3.34

Production Casing Collapse Safety Factor:

1/3 Evacuation Diff Pressure = [(4390 x 0.052 x 8.55) - (4390 / 3 x 0.052 x 8.34)] = 1317
Cementing Diff Lift Pressure = [(1190 x 0.052 x 11.8) + (3200 x 0.052 x 14.5) - 1904] = 1239
Collapse Safety Factor = 4910 / 1317 = 3.73

Tensial Strength – ConocoPhillips Required Load Cases

The maximum axial (tension) load occurs if casing were to get stuck and pulled on to try to get it unstuck.

Maximum Allowable Axial Load for Pipe Yield = API Pipe Yield Strength Rating / Corporate Minimum Axial Design Factor
Maximum Allowable Axial Load for Joint = API Joint Strength Rating / Corporate Minimum Axial Design Factor
Maximum Allowable Hook Load (Limited to 75% of Rig Max Load) = Maximum Allowable Axial Load
Maximum Allowable Overpull Margin = Maximum Allowable Hook Load - Bouyant Wt of the String
Tensial Safety Factor = API Pipe Yield 'OR' API Joint Strength 'OR' Rig Max Load Rating / (Bouyant Wt of String + Minimum Overpull Required)

Rig Max Load (300,000 lbs) x 75% = 225000 lbs
Minimum Overpull Required = 50000 lbs

Surface Casing Tensial Strength Safety Factor:

Air Wt = 22128
Bouyant Wt = 22128 x 0.870 = 19256
Max. Allowable Axial Load (Pipe Yield) = 381000 / 1.40 = 272143
Max. Allowable Axial Load (Joint) = 244000 / 1.40 = 174286
Max. Allowable Hook Load (Limited to 75% of Rig Max Load) = 174286
Max. Allowable Overpull Margin = 174286 - (22128 x 0.870) = 155029
Tensial Safety Factor = 244000 / (19256 + 50000) = 3.52

Production Casing Tensial Strength Safety Factor:

Air Wt = 74630
Bouyant Wt = 74630 x 0.847 = 63236
Max. Allowable Axial Load (Pipe Yield) = 273000 / 1.40 = 195000
Max. Allowable Axial Load (Joint) = 247000 / 1.40 = 176429
Max. Allowable Hook Load (Limited to 75% of Rig Max Load) = 176429
Max. Allowable Overpull Margin = 176429 - (74630 x 0.847) = 113192
Tensial Safety Factor = 247000 / (63236 + 50000) = 2.18

Compression Strength – ConocoPhillips Required Load Cases

The maximum axial (compression) load for the well is where the surface casing is landed on the conductor with a support of a plate or landing ring. The surface casing is also calculated to bear 60% of the load but not limited. Any other axial loads such as a snubbing unit or other, would need to be added to the load.

Compression Safety Factor = API Axial Joint Strength Rating 'OR' API Axial Pipe Yield Rating / Maximum Predicted Load

Wellhead Load = 3000 lbs

Conductor & Surface Compression Safety Factor

Surf Casing Wt (Bouyant) = (22128 x 0.870) = 19256
Prod Casing Wt (Bouyant) = (74630 x 0.847) = 63236
Tubing Wt (Air Wt) = 4390 x 6.5 = 28535
Tubing Fluid Wt = 4390 x 0.052 x 6.55 x 0.7854 x 2.441 ^2 = 6997
Load on Conductor = 3000 + 19256 + 63236 + 28535 + 6997 = 121025
Conductor Compression Safety Factor = 432966 / 121025 = 3.58
Load on Surface Casing = 121025 x 60% = 72615
Surface Casing Compression Safety Factor = 244000 / 72615 = 3.36

3. **Proposed cementing program:**

16" or 13-3/8" Conductor:

Cement to surface with rathole mix, ready mix or Class C Neat cement.
(Note: The gravel used in the cement is not to exceed 3/8" diameter)
TOC at surface.

8-5/8" Surface Casing Cementing Program:

The intention for the cementing program for the Surface Casing is to:

- Place the Tail Slurry from the casing shoe to 300' above the casing shoe,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	Class C	Surface	577' – 622'	13.6	300	510	+ 2% Extender + 2% $CaCl_2$ + 0.125 lb/sx Lost Circulation Control Agent + 0.2% Defoamer Excess =200% based on gauge hole volume	1.70
Tail	Class C	577' – 622'	877' – 922'	14.8	200	268	1% CaCl2 Excess = 100% based on gauge hole volume	1.34

Displacement: Fresh Water.

Note: In accordance with the Pecos District Conditions of Approval, we will Wait on Cement (WOC) for a period of not less than 18 hrs after placement or until at least 500 psi compressive strength has been reached in both the Lead Slurry and Tail Slurry cements on the Surface Casing, whichever is greater.

5-1/2" Production Casing Cementing Program – Single Stage Cementing Option:

The intention for the cementing program for the Production Casing – Single Stage Cementing Option is to:

- Place the Tail Slurry from the casing shoe to above the top of the Paddock,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	50:50 Poz/C	Surface	3200'	11.8	450	1031	+ 10 % Extender + 5 % NaCl + 0.2 % Defoamer + 5 lb/sx LCM/Extender + 0.125 lb/sx Lost Circulation Control Agent + 0.5 % Fluid Loss Excess = 20% or more if needed based on gauge hole volume	2.29
Tail	Poz/C CO2 Resistant Cement	3200'	4345' – 4390'	14.5	300	378	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 60% or more if needed based on gauge hole volume	1.26

Displacement: Fresh Water with approximately 250 ppm gluteraldehyde biocide.

5-1/2" Production Casing Cementing Program – Two-Stage Cementing Option: See COA

ConocoPhillips Company respectfully requests the options to our cementing program. The intention for the cementing program for the Production Casing – Two-Stage Cementing Option is to:

- Provide a contingency plan for using a Stage Tool and Annulus Casing Packer(s) to isolate losses or waterflow if either of these events occurs while drilling the well.
- Place the Stage 1 Cement from the casing shoe to the stage tool,
- Bring Stage 2 Cement from the stage tool to surface.

Spacer: 20 bbls Fresh Water

Stage 1 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	Poz/C CO2 Resistant Cement	3200'	4345' – 4390'	14.5	300	378	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 60% or more if needed based on gauge hole volume	1.26

Stage 2 - Slurry		Intervals Ft MD		Weight ppg	Sx	Vol Cuft	Additives	Yield ft^3/sx
Lead	50:50 Poz/C	Surface	1400'	11.8	250	573	+ 10 % Extender + 5 % NaCl + 0.2 % Defoamer + 5 lb/sx LCM/Extender + 0.125 lb/sx Lost Circulation Control Agent + 0.5 % Fluid Loss Excess = 120% or more if needed based on gauge hole volume	2.29
Tail	Poz/C CO2 Resistant Cement	1400'	Stage Tool ~ 3200'	14.5	400	504	+ 1 % Extender + 0.5 % Fluid Loss + 0.4 % Dispersant + 0.2 % Defoamer Excess = 10% or more if needed based on gauge hole volume	1.26

Displacement: Fresh Water

Proposal for Option to Adjust Production Casing Cement Volumes:

The production casing cement volumes for the proposed single stage and two-stage option presented above are estimates based on gauge hole. We will adjust these volumes based on the caliper log data for each well and our trends for amount of cement returns to surface. Also, if no caliper log is available for any particular well, we would propose an option to possibly increase the production casing cement volume to account for any uncertainty in regard to the hole volume.

4. **Pressure Control Equipment:**

A __11" 3M__ system will be installed, used, maintained, and tested accordingly as described in Onshore Oil and Gas Order No. 2.

Our BOP equipment will be:
- o Rotating Head
- o Annular BOP, 11" 3M
- o Blind Ram, 11" 3M
- o Pipe Ram, 11" 3M

After nippling up, and every 30 days thereafter or whenever any seal subject to test pressure is broken followed by related repairs, blowout preventors will be pressure tested. BOP will be inspected and operated at least daily to insure good working order. All pressure and operating tests will be done by an independent service company and recorded on the daily drilling reports. BOP will be tested using a test plug to isolate BOP stack from casing. BOP test will include a low pressure test from 250 to 300 psi for a minimum of 10 minutes or until requirements of test are met, whichever is longer. Ram type preventers and associated equipment will be tested to the approved stack working pressure of 3000 psi isolated by test plug. Annular type preventers will be tested to 50 percent of rated working pressure, and therefore will be tested to 1500 psi. Pressure will be held for at least 10 minutes or until provisions of test are met, whichever is longer. Valve on casing head below test plug will be open during testing of BOP stack. BOP will comply with all provisions of Onshore Oil and Gas Order No. 2 as specified. **See Attached BOPE Schematic.** A variance is respectfully requested to allow for the use of flexible hose. The variance request is included as a separate enclosure with attachments.

5. **Proposed Mud System:**

The mud systems that are proposed for use are as follows:

DEPTH	TYPE	Density ppg	FV sec/qt	API Fluid Loss cc/30 min	pH	Vol bbl
0 – Surface Casing Point	Fresh Water or Fresh Water Native Mud in Steel Pits	8.5 – 9.0	28 – 40	N.C.	N.C.	300 – 500
Surface Casing Point to TD	Brine (Saturated $NaCl_2$) in Steel Pits	10	29	N.C.	10 – 11	500 – 1000
Conversion to Mud at TD	Brine Based Mud ($NaCl_2$) in Steel Pits	10	33 – 40	5 – 10	10 – 11	0 – 500

Gas detection equipment and pit level flow monitoring equipment will be on location. A flow paddle will be installed in the flow line to monitor relative amount of mud flowing in the non-pressurized return line. Mud probes will be installed in the individual tanks to monitor pit volumes of the drilling fluid with a pit volume totalizer. Gas detecting equipment and H2S monitor alarm will be installed in the mud return system and will be monitored. A mud gas separator will be installed and operable before drilling out from the Surface Casing. The gases shall be piped into the flare system. Drilling mud containing H2S shall be degassed in accordance with API RP-49, item 5.14.

In the event that the well is flowing from a waterflow, then we would discharge excess drilling fluids from the steel mud pits through a fas-line into steel frac tanks at an offset location for containment. Depending on the rate of waterflow, excess fluids will be hauled to an approved disposal facility, or if in suitable condition, may be reused on the next well.

No reserve pit will be built.

Proposal for Option to Not Mud Up at TD:
FW, Brine, and Mud volume presented above are estimates based on gauge 12-1/4" or 7-7/8" holes. We will adjust these volume based on hole conditions. We do not plan to keep any weighting material at the wellsite. Also, we propose an option to not mud up leaving only brine in the hole if we have good hole stability.

6. **Logging, Coring, and Testing Program:**
   a. No drill stem tests will be done
   b. Remote gas monitoring planned for the production hole section (optional).
   c. No whole cores are planned
   d. The open hole electrical logging program is planned to be as follows:
      - Total Depth to 1700': Spectral GR, Gamma Ray, Resistivity, Density, and BHC Sonic
      - Total Depth to surface Casing Shoe: Caliper
      - Total Depth to surface, Gamma Ray and Neutron
      - Total Depth to 3200'; Dielectric Scanner
      - Formation pressure data (XPT) on electric line
      - Rotary Sidewall Cores on electric line if needed (optional)
      - FMI (Formation MicroImager) if needed (optional)
      - UBI (Ultrasonic Borehole Imager) if needed (optional)

7. **Abnormal Pressures and Temperatures:**

- No abnormal pressures are expected to be encountered.

- Loss of circulation is a possibility in the horizons below the Top of Grayburg. We expect that normal Loss of Circulation Material will be successful in healing any such loss of circulation events.

  - The bottom hole pressure is expected to be 8.55 ppg gradient.
  - The expected Bottom Hole Temperature is 115 degrees F.

- The estimated H_2S concentrations and ROE calculations for the gas in the zones to be penetrated are presented in the table below for the various producing horizons in this area:

FORMATION / ZONE	H2S (PPM)	Gas Rate (MCFD)	ROE 100 PPM	ROE 500 PPM
Grayburg / San Andres (from MCA)	14000	38	59	27

ConocoPhillips will comply with the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations. Also, ConocoPhillips will provide an H2S Contingency Plan (please see copy attached) and will keep this plan updated and posted at the wellsite during the drilling operation.

8. **Anticipated starting date and duration of operations:**

Well pad and road constructions will begin as soon as all agency approvals are obtained. Anticipated date to drill this well is late 2013 after receiving approval of the APD.

Attachments:

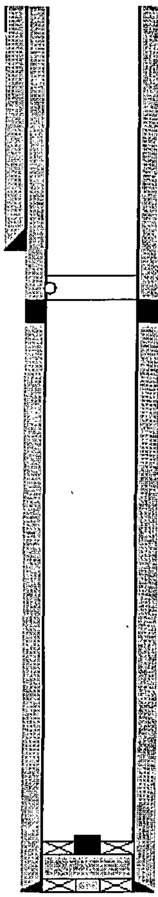
- Attachment # 1 ....Two-stage Cementing Schematic
- Attachment # 2........BOP and Choke Manifold Schematic – 3M System
- Attachment # 3........Diagram of Choke Manifold Equipment

Contact Information:

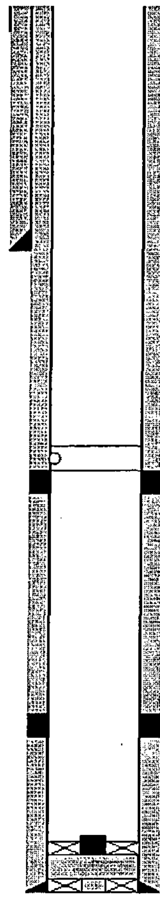
Proposed 22 April 2013 by:
James Chen
Drilling Engineer, ConocoPhillips Company
Phone (832) 486-2184
Cell (832) 768-1647

Attachment # 1

Two-Stage Cementing (Alternative for Shallow Gas)
Provide contingency plan for using two-stage cementing for the production casing cement job if gas flow occurs during the drilling operations. See APD Drill Plan Section 3. Proposed cementing program.

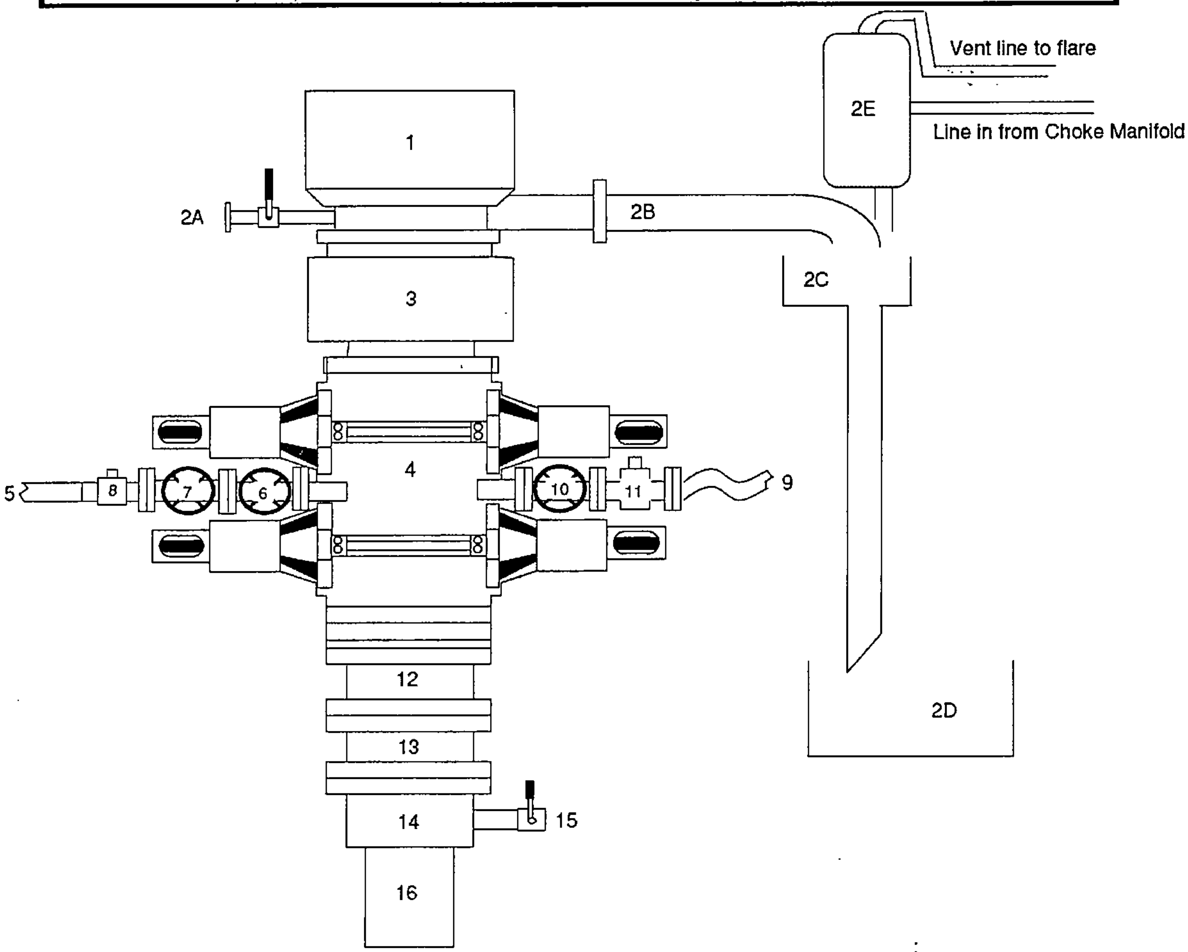


Two-Stage Cementing (Alternative for Oil / Water / Gas & Water Flow)
Provide contingency plan for using two-stage cementing for the production casing cement job if oil or water flow occurs during the drilling operations. See APD Drill Plan Section 3. Proposed cementing program.



Attachment # 2

BLOWOUT PREVENTER ARRANGEMENT
3M System per Onshore Oil and Gas Order No. 2 utilizing 3M and 5M Rated Equipment



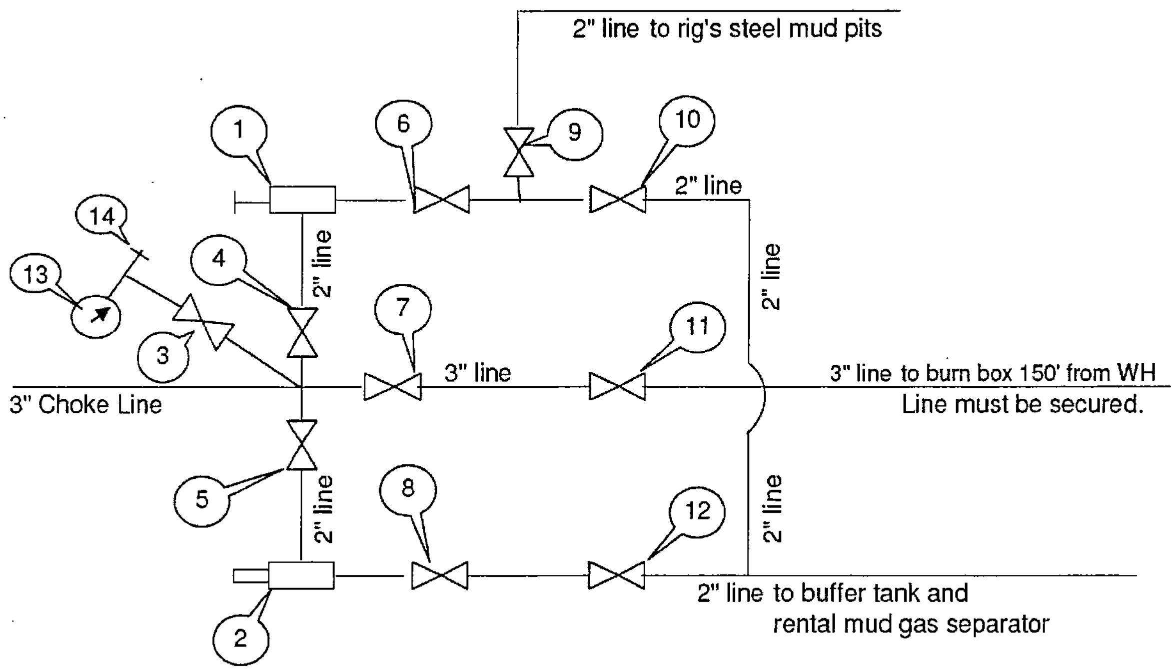
Item	Description
1	Rotating Head, 11"
2A	Fill up Line and Valve
2B	Flow Line (10")
2C	Shale Shakers and Solids Settling Tank
2D	Cuttings Bins for Zero Discharge
2E	Rental Mud Gas Separator with vent line to flare and return line to mud system
3	Annular BOP (11", 3M)
4	Double Ram (11", 3M, equipped with Blind Rams and Pipe Rams)
5	Kill Line (2" flexible hose, 3000 psi WP)
6	Kill Line Valve, Inner (3-1/8", 3000 psi WP)
7	Kill Line Valve, Outer (3-1/8", 3000 psi WP)
8	Kill Line Check Valve (2-1/16", 3000 psi WP
9	Choke Line (5M Stainless Steel Coflex Line, 3-1/8" 3M API Type 6B, 3000 psi WP)
10	Choke Line Valve, Inner (3-1/8", 3000 psi WP)
11	Choke Line Valve, Outer, (Hydraulically operated, 3-1/8", 3000 psi WP)
12	Adapter Flange (11" 5M to 11" 3M)
13	Spacer Spool (11", 5M)
14	Casing Head (11" 5M)
15	Ball Valve and Threaded Nipple on Casing Head Outlet, 2" 5M
16	Surface Casing

Submitted by: James Chen, Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company, 25-Sep-2012

Attachment # 3

CHOKE MANIFOLD ARRANGEMENT

3M System per Onshore Oil and Gas Order No. 2 utilizing 3M and 5M Equipment



All Tees must be targeted

Item	Description
1	Manual Adjustable Choke, 2-1/16", 3M
2	Remote Controlled Hydraulically Operated Adjustable Choke, 2-1/16", 3M
3	Gate Valve, 2-1/16" 5M
4	Gate Valve, 2-1/16" 5M
5	Gate Valve, 2-1/16" 5M
6	Gate Valve, 2-1/16" 5M
7	Gate Valve, 3-1/8" 3M
8	Gate Valve, 2-1/16" 5M
9	Gate Valve, 2-1/16" 5M
10	Gate Valve, 2-1/16" 5M
11	Gate Valve, 3-1/8" 3M
12	Gate Valve, 2-1/16" 5M
13	Pressure Gauge
14	2" hammer union tie-in point for BOP Tester

We will test each valve to 3000 psi from the upstream side.

Submitted by:
James Chen
Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company
Date: 21-March-2013

Request for Variance

ConocoPhillips Company
Lease Number: USA LC 058698A
Well: MCA Unit #456
Location: Sec. 26, T17S, R32E
Date: 04-21-13

Request:

ConocoPhillips Company respectfully requests a variance to install a flexible choke line instead of a straight choke line prescribed in the Onshore Order No. 2, III.A.2.b Minimum standards and enforcement provisions for choke manifold equipment. This request is made under the provision of Onshore Order No. 2, IV Variances from Minimum Standard. The rig to be used to drill this well is equipped with a flexible choke line if the requested variance is approved and determined that the proposed alternative meets the objectives of the applicable minimum standards.

Justifications:

The applicability of the flexible choke line will reduce the number of target tees required to make up from the choke valve to the choke manifold. This configuration will facilitate ease of rig up and BOPE Testing.

Attachments:

- Attachment # 1 Specification from Manufacturer
- Attachment # 2 Mill & Test Certification from Manufacturer

Contact Information:

Program prepared by:
James Chen
Drilling Engineer, ConocoPhillips Company
Phone (832) 486-2184
Cell (832) 768-1647
Date: 26 September 2012

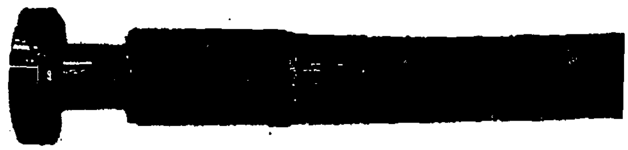
Attachment # 1

RELIANCE Industrial Products USA, Ltd.

[redacted]

[redacted]

RELIANCE



Reliance Eliminator Choke & Kill

This hose can be used as a choke hose which connects the BOP stack to the bleed-off manifold or a kill hose which connects the mud stand pipe to the BOP kill valve.

The Reliance Eliminator Choke & Kill hose contains a specially bonded compounded cover that replaces rubber covered Asbestos, Fibreglass and other fire retardant materials which are prone to damage. This high cut and gouge resistant cover overcomes costly repairs and downtime associated with older designs.

The Reliance Eliminator Choke & Kill hose has been verified by an independent engineer to meet and exceed EUB Directive 36 (700°C for 5 minutes).

Nom. ID		Nom OD		Weight		Min Bend Radius		Max WP	
in.	mm.	in.	mm	lb/ft	kg/m	in.	mm.	psi	Mpa
3	76.2	5.11	129.79	14.5	21.46	48	1219.2	5000	34.47
3-1/2	88.9	5.79	147.06	20.14	29.80	54	1371.6	5000	34.47

[redacted]

Fittings	Flanges	Hammer Unions	Other
RC4X5055	R35 - 3-1/8 5000# API Type 6B	All Union Configurations	LP Threaded Connectio
RC3X5055	R31 - 3-1/8 3000# API Type 6B		Graylock
RC4X5575			Custom Ends

Attachment # 2

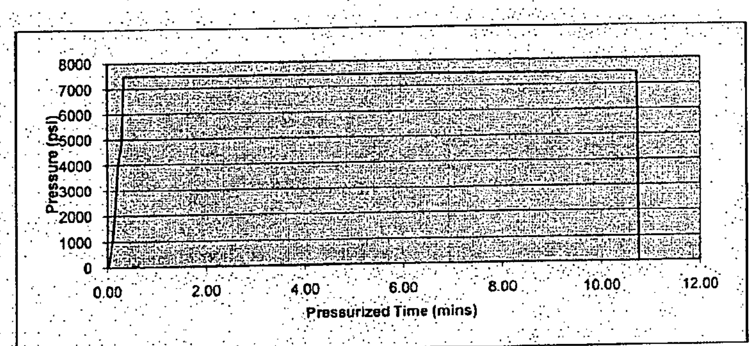
RELIANCE
Industrial Products USA, Ltd.

2030 E. 8th Street, Suite B • Greeley, CO 80631
Ph: (970) 346-3751 • Fax: (970) 353-3168 • *Toll Free:* (866) 771-9739

TEST CERTIFICATE

Customer:	PRECISION DRILLING
P.O. #:	RIG 822
Invoice #:	27792
Material:	3 1/2" FIREGUARD
Description:	3 1/2" X 10'
Coupling 1:	3 1/2" FLANGE R31
" Serial:	
" Quality:	
Coupling 2:	3 1/2" FLOATING R31
" Serial:	
" Quality:	
Working Pressure:	3000
Test Pressure:	7500
Duration (mins):	10

Cert No.: 27792
Date: 9/21/2012



Conducted By: FLORES M.
Test Technician

☑ Acceptable
☐ Not Acceptable