11-917

Form 3160-3
(August 2007)

FORM APPROVED
OMB No. 1004-0137
Expires July 31, 2010

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

HOBBS OCD
OCD Hobbs
SEP 12 2011
RECEIVED

APPLICATION FOR PERMIT TO DRILL OR REENTER

Split Estate

1a. Type of work: [X] DRILL [ ] REENTER	5. Lease Serial No. NMLC031695B
1b. Type of Well: [X] Oil Well [ ] Gas Well [ ] Other [ ] Single Zone [ ] Multiple Zone	6. If Indian, Allotee or Tribe Name
2. Name of Operator ConocoPhillips Company <217817>	7. If Unit or CA Agreement, Name and No. Warren Unit <31493>
3a. Address 3300 N "A" St, Bldg 6 Midland, TX 79705	8. Lease Name and Well No. Warren Unit 398 ~~Warren~~ BL-TU WF 398 <31488>
3b. Phone No. (include area code) (432)688-6913	9. API Well No. 30-025-40295
4. Location of Well (Report location clearly and in accordance with any State requirements.*) At surface 1360 FNL 1370 FEL Unit G; At proposed prod. zone	10. Field and Pool, or Exploratory Warren;Blinebry-Tub/Drinkard <62109> / Warren <63080>
	11. Sec., T. R. M. or Blk. and Survey or Area Sec 29 T20S R38E
14. Distance in miles and direction from nearest town or post office* 7.63 miles north of Eunice, NM	12. County or Parish Lea; 13. State NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) 1360	16. No. of acres in lease 5120.00	17. Spacing Unit dedicated to this well 40.00
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 1008' from Warren Burger 7	19. Proposed Depth 7180	20. BLM/BIA Bond No. on file ES0085
21. Elevations (Show whether DF, KDB, RT, GL, etc.) 3535 GL	22. Approximate date work will start* 12/16/2011	23. Estimated duration 12/23/2011

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	Name (Printed/Typed) Brian D Maiorino	Date 08/08/2011
Title Regulatory Specialist		
Approved by (Signature) /s/ Don Peterson	Name (Printed/Typed)	Date SEP 08 2011
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)

KZ 09/14/11

Approval Subject to General Requirements & Special Stipulations Attached

SEE ATTACHED FOR CONDITIONS OF APPROVAL

Lea County Controlled Water Basin

SEP 15 2011

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SELF-CERTIFICATION STATEMENT FROM LESSEE/OPERATOR

SURFACE OWNER IDENTIFICATION

Federal or Indian Lease No. ____________________

Well(s) Number and Location ____________________

Warren Unit # 398, G, 29, 20S, 38E, 1360 FNL 1370 FEL

I hereby certify to the Authorized Officer of the Bureau of Land Management that I have reached one of the following agreements with the Surface Owner; or after failure of my good-faith effort to come to an agreement of any kind with the Surface Owner, I will provide a bond:

1) X I have a signed access agreement to enter the leased lands;

2) ______ I have a signed waiver from the surface owner;

3) ______ I have entered into an agreement regarding compensation to the surface owner for damages for loss of crops and tangible improvements.

4) ______ Because I have been unable to reach either 1), 2), or 3) with the surface owner, I will obtain a bond to cover loss of crops and damages to tangible improvements.

Surface owner information: (if available after diligent effort)

Surface Owner Name: Robert McCasland

Surface Owner Address: PO Box 206, Eunice, NM 88231

Surface Owner Phone Number: 575-394-3022

Signed this 8 day of August, 2011.

ConocoPhillips Company

(Name of lessee/operator)

Warren Unit 398

Formation Tops and Planned Total Depth

Formation Call Points	Top (ft MD)
Rustler	1420
Salado	1495
Tansill	2558
Yates	2710
Seven Rivers	2968
Queen	3529
Penrose	3688
Grayburg	3865
San Andres	4100
Glorieta	5401
Paddock	5540
Blinebry	5665
Tubb	6400
Drinkard	6713
Deepest Estimated Perforation	6980 — See COA
Abo	7000
Total Depth (minimum)	7135
Total Depth (maximum)	7180

Casing Depths

String	Minimum Depth	Maximum Depth
Surface Casing	~~1445~~	~~1485~~ — approximately 1450' see COA
Production Casing	7125	7170

Note: The Surface Casing will be set at least 25' into the Rustler formation and above the Salado (salt). A pup joint will be used if necessary to ensure that we get the cementing head down to the floor and that we stay within that range on the shoe set depth. The Production Casing program reflects an uncertainty of 45' in the setting depth for the shoe because that is the approximate length of a full joint of Range 3 casing. This range for the setting depth will allow us to drill the hole to fit the casing string based on how the tally comes out and will provide for the cementing head to be positioned at the rig floor for safety and efficiency in cementing operations. The Surface Casing and Production Casing will be set approximately 10 ft off bottom.

Tom
1 Apr 2011

Master Drilling Plan
ConocoPhillips Company
Warren Unit
June 28, 2011

Warren Field
Lea County, New Mexico

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

The names, estimated tops, and thicknesses of the formations expected to be encountered, and the zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals, will be provided for each well on a separate document.

The ranges of depths for the formation tops, thicknesses, and planned Total Depths for 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 14' above Ground Level).

Formation Call	Formation Top FT MD	Thickness ft	Contents
Quaternary	Surface		Fresh Water
Rustler	1413 - 1543	65 - 90	Anhydrite
Salado (top of salt)	1493 - 1633	1033 - 1070	Salt
Tansill (base of salt)	2544 - 2703	135 - 154	Gas, Oil and Water
Yates	2698 - 2838	258 - 282	Gas, Oil and Water
Seven Rivers	2961 - 3100	548 - 617	Gas, Oil and Water
Queen	3521 - 3717	130 - 166	Gas, Oil and Water
Penrose	3675 - 3847	154 - 179	Gas, Oil and Water
Grayburg	3846 - 4001	226 - 260	Gas, Oil and Water
San Andres	4088 - 4232	1274 - 1333	Gas, Oil and Water
Glorieta	5375 - 5565	48 - 160	Gas, Oil and Water
Paddock	5515 - 5613	85 - 218	Gas, Oil and Water
Blinebry	5622 - 5801	658 - 740	Gas, Oil and Water
Tubb	6312 - 6468	304 - 357	Gas, Oil and Water
Drinkard	6630 - 6825	138 - 296	Gas, Oil and Water
Deepest estimated perforation	6902 - 7000		~~Deepest estimated perforation is ~20' above Top of Abo~~
Abo	6922 - 7020		TD is in the Abo to provide rathole below objective horizons
Total Depth (minimum)	7057 - 7155		155' below deepest estimated perforation
Total Depth (maximum)	7102 - 7200		200' below deepest estimated perforation

Below Blinebry - Tubb See COA

Protection of fresh water will be accomplished by setting the surface casing at least 25' into the Rustler Anhydrite formation, but above the top of the Salado Salt, and **cementing** the surface casing from the casing shoe **to the surface of ground** in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

Protection of oil and gas resources will be accomplished by setting the production casing approximately 10' off bottom and cementing it in accordance with the provisions Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

TMM 1 Sep 2011

2. Proposed casing program:

Type	Hole Size (in)	Interval MD RKB (ft) From	To	OD (inches)	Wt (lb/ft)	Gr	Conn	Condition	Safety Factors Calculated per BLM Load Formulas Burst	Collapse	Tension Dry/Buoyant
Cond	20"	0	~ 73' (~ 57' BGL)	16"	0.5" wall	B	Line Pipe	New	NA	NA	NA
Alt. Cond	20"	0	~ 73' (~ 57' BGL)	13-3/8"	48#	H-40	PE	New	NA	NA	NA
Surf	12-1/4"	0	~~1438' – 1613'~~ approximately 1450' See COA	8-5/8"	24#	J-55	STC	New	4.22	1.92	6.30 / 7.24
Prod	7-7/8"	0	7057' – 7200'	5-1/2"	17#	L-80	LTC	New	2.41	1.68	2.76 / 3.25

The casing will be suitable for H_2S Service.

The surface casing will be set at least 25' into the Rustler Anhydrite formation, but above the top of the Salado Salt, and **cemented to the surface of ground** in accordance with the provisions of Onshore Oil and Gas Order No. 2 and New Mexico Oil Conservation Division Title 19.

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.

The perforations will be above the top of the Abo and the deepest estimated perforation is estimated to be approximately 20' above the top of the Abo.

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

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Casing Design (Safety) Factors – BLM Criteria:

Joint Strength Design (Safety) Factor: SFt
SFt = Fj / Wt;
Where

- Fj is the rated pipe Joint Strength in pounds (lbs)
- Wt is the weight of the casing string in pounds (lbs)

The Minimum Acceptable Joint Strength Design (Safety) Factor SFT = 1.6 dry or 1.8 buoyant

Collapse Design (Safety) Factor: SFc
SFc = Pc / (MW x .052 x Ls)
Where

- Pc is the rated pipe Collapse Pressure in pounds per square inch (psi)
- MW is mud weight in pounds per gallon (ppg)
- Ls is the length of the string in feet (ft)

The Minimum Acceptable Collapse Design (Safety) Factor SFc = 1.125

Burst Design (Safety) Factor: SFb
SFb = Pi / BHP
Where

- Pi is the rated pipe Burst (Minimum Internal Yield) Pressure in pounds per square inch (psi)
- BHP is bottom hole pressure in pounds per square inch (psi)

The Minimum Acceptable Burst Design (Safety) Factor SFb = 1.0

Joint Strength Design (Safety) Factors – BLM Criteria

Surface Casing:

- SFj Dry = 244,000 lbs / (1613 ft x 24 lb/ft) = 244,000 lbs / 38,712 lbs = 6.30 Dry
- SFj Bouyant = 244,000 lbs / (1613 ft x 24 lb/ft) [1-(8.5/65.5)] = 244,000 lbs / 33,688 lbs = 7.24 Buoyant

Production Casing:

- SFj Dry = 338,000 lbs / (7200 ft x 17 lb/ft) = 338,000 lbs / 122,400 lbs = 2.76 Dry
- SFj Bouyant = 338,000 lbs / (7200 ft x 17 lb/ft) [1-(10.0/65.5)] = 338,000 lbs / 103,713 lbs = 3.25 Buoyant

Collapse Design (Safety) Factors – BLM Criteria

Surface Casing:
SFc = 1370 psi / (8.5 ppg x 052 x 1613 ft) = 1370 psi / 713 psi = 1.92
Production Casing:
SFc = 6290 psi / (10 ppg x .052 x 7200 ft) = 6290 psi / 3744 psi = 1.68

Burst Design (Safety) Factors – BLM Criteria

Surface Casing:
SFb = 2950 psi / (8.33 ppg x .052 x 1613 ft) = 2950 psi / 698 psi = 4.22
Production Casing:
SFb = 7740 psi / (8.5 ppg x .052 x 7200 ft) = 7740 psi / 3201 psi = 2.41 based on est. reservoir pressure data

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1 Sep 2011

Casing Design (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

Surface Casing:

The maximum internal (burst) load on the Surface Casing occurs when the surface casing is tested to 1500 psi. We will pressure up to 1600 psi and let the pressure settle for 1 minute after shutting down the pump. Then we will begin the 30 minute test period. Therefore the maximum pressure that the surface casing will be exposed to will be 1600 psi.

Surface Casing Burst Design Factor
DF Burst = Burst Rating / Maximum Pressure During Casing Pressure Test = 2950 psi / 1600 psi = 1.84

The maximum collapse load on the Surface Casing occurs when we release the pressure after bumping the plug on the surface casing cement job.

Surface Casing Collapse Design Factor
DF Collapse = Collapse Rating / (Cement Column Hydrostatic Pressure – Displacement Fluid Hydrostatic Pressure)
DF Collapse = 1370 psi / {[(350 ft x .052 x 14.8 ppg) + (1263 ft x .052 x 13.6 ppg)] – (1613 ft x 052 x 8.33 ppg)}
DF Collapse = 1370 psi / 463 psi
DF Collapse = 2.95

The maximum axial load on the Surface Casing would occur if we were to get the surface casing stuck and pull on it to try to get it unstuck.

Surface Casing Axial (Tension) Maximum Allowable Hook Load Case:
Maximum Allowable Hookload = Joint Strength Rating / Axial Design Factor
Maximum Allowable Hookload = 244,000 / 1.4
Maxium Allowable Hookload = 174,286

Overpull Margin = Maximum Allowable Hook Load - Air Wt of the String
Overpull Margin = 174,286 lbs - (1613' x 24 lb/ft)
Overpull Margin = 174,286 lbs – 38,712 lbs
Overpull Margin = 135,574 lbs

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Production Casing:

The maximum internal (burst) load would occur in the fracture stimulation either during fracture initiation or screen out.

The Maximum Allowable Working Pressure (MAWP) that we would impose in the fracture stimulation load case is the pressure that would result in a 1.15 burst design factor at surface.

For this well
MAWP for the Fracture Stimulation = Minimum Internal Yeild / 1.15
MAWP for the Fracture Stimulation = 7740 psi / 1.15
MAWP for the Fracture Stimulation = 6730 psi

A pressure relief valve and pump truck kill settings will also be used to prevent overpressuring the production casing in the event of a screen out.

The maximum collapse load on the production casing occurs with the well pumped off on production.

DF Collapse = Collapse Rating / Bottom Hole Pressure
DF Collapse = 6290 psi / (8.5 ppg x .052 x 7200 ft) = 6290 psi / 3182 psi = 1.97

The maximum axial load on the Production Casing would occur if we were to get the Production Casing stuck and pull on it to try to get it unstuck.

Production Casing Axial (Tension) Maximum Hook Load Case:
Maximum Allowable Hookload = Joint Strength Rating / Axial Design Factor
Maximum Allowable Hookload = 338,000 lbs / 1.4
Maximum Allowable Hookload = 241,428 lbs

Overpull Margin = Maximum Allowable Hook Load - Air Wt of the String
Overpull Margin = 241,428 lbs - (7200' x 17 lb/ft)
Overpull Margin = 241,428 lbs – 122,400 lbs
Overpull Margin = 119,028 lbs

TMM
1 Sep 2011

3. **Proposed cementing program:**

16" or 13-3/8" Conductor:

Cement to surface with rat hole mix, ready mix or Class C Neat cement.

(Note: The gravel used in the cement is not to exceed 3/8" dia)

TOC at surface.

8-5/8" Surface Casing:

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

- Place the Tail Slurry from the casing shoe to 350' above the casing shoe,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Lead Slurry								
Volume (sx) & Recipe & Excess %	Top (ft MD)	Bottom (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 90 deg F by UCA Method	
500-550 sx Class C + 4% bentonite + 2% CaCl2 + 0.125% Polyflake + 0.2% Antifoam Excess = 68%	Surface	1088 (min) 1263 (max)	1088 (min) 1263 (max)	13.6	1.71	8.923	Time 2 hrs 15 min 7 hrs 52 min 24 hrs 48 hrs 72 hrs	Strength 50 psi 500 psi 1173 psi 1542 psi 1739 psi

Tail Slurry								
Volume (sx) & Recipe & Excess %	Top (ft MD)	Bottom (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 90 deg F by UCA Method	
250 sx Class C + 1% CaCl2 Excess = 100%	1088 (min) 1263 (max)	1438 (min) 1613 (max)	350	14.8	1.34	6.371	Time 2 hrs 36 min 5 hrs 17 min 24 hrs 48 hrs 72 hrs	Strength 50 psi 500 psi 2026 psi 2572 psi 2846 psi

Displacement: Fresh Water

The calculated average hole size for the surface hole for wells in the Warren Unit is 13.22" to 13.88" diameter based on volume of cement pumped and volume of cement returns to surface. Therefore this volume of cement should result in approximately 35 - 40 bbls of cement returns to surface.

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:

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

- Place the Tail Slurry from the casing shoe to a point approximately 200' above the top of the Paddock,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water.

Lead Slurry								
Volume (sx) & Recipe & Excess %	Top (ft MD)	Bottom (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
700 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125%LCM if needed	Surface	5315 (min) 5413 (max)	5315 (min) 5413 (max)	11.8	2.55	14.88	Time 12 hrs 24 hrs 48 hrs 72 hrs	Strength 100 psi 200 psi 245 psi 310 psi
Excess = 40% or more if needed based on caliper if available. Estimated average hole size = 9" Note: This compressive strength data is from an old pilot test (20-Feb-2007) for this slurry and will be updated.								

Tail Slurry								
Volume (sx) & Recipe & Excess %	Top (ft MD)	Bottom (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
350 sx 50% Class H 50% POZ + 2% Bentonite + 5% Salt + 0.4% Fluid Loss Additive + 0.2% Dispersant + Retarder if needed + Antifoam if needed	5315 (min) 5413 (max)	7057 (min) 7200 (max)	1742 (min) 1828 (max)	14.2	1 32	6.20	Time 12 hrs 24 hrs 48 hrs 72 hrs	Strength 800 psi 1100 psi 1410 psi 1720 psi
Excess = 40% or more if needed based on caliper if available. Estimated average hole size = 8.2" Note: This compressive strength data is from an old pilot test (20-Feb-2007) for this slurry and will be updated.								

Displacement: Fresh Water with approximately 250 ppm gluteraldehyde biocide.

Proposal for Option to Adjust Production Casing Cement Volumes:

The production casing cement volumes presented above are estimates based on data from previous wells. We will adjust these volumes based on the caliper log data for each well and our trends for amount of cement returns to surface and possibly reduce the excess % if we observe that we are getting excessive amounts of cement back to surface.

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1 Sep 2011

4. Pressure Control Equipment:

The blowout preventer equipment (BOP) will conform to the requirements for a 2M System as described in Onshore Oil and Gas Order No. 2. However we will substitute higher rated BOP equipment and use additional equipment not required for a 2M System.

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

The blowout preventer equipment will be installed after running and cementing the surface casing and installing the wellhead on the surface casing.

Testing of the BOP equipment will be as follows:

- The appropriate BLM office shall be notified a minimum 4 hours in advance for a representative to witness the tests.
- The tests shall be done by an independent service company.
- The results of the test shall be reported to the appropriate BLM office.
- 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.
- 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.
- Ram type preventers and associated equipment shall be tested to approved stack working pressure of 3000 psi. The Annular type preventer will be tested to 50 percent of rated working pressure, and therefore will be tested to 1500 psi. The above tests will be performed:
  - When initially installed
  - Whenever any seal subject to test pressure is broken
  - Following related repairs, and
  - At 30 day intervals
- Annular preventers, if used, will be functionally operated at least weekly.
- Pipe and Blind rams shall be activated each trip, but not more than once per day.
- All of the above described tests will be recorded in the drilling log.

A diagram of the proposed BOPs and choke manifold is attached.

The Working Pressure Requirement for the BOP equipment is calculated per Onshore Order 2 as follows:
- Reservoir Pressure = 3005 psi at deepest estimated perforation depth of 6758' MD (8.55 ppg gradient)
- Bottom Hole Pressure = 8.55 ppg x .052 x 6958' = 3093 psi
- Required Working Pressure for the BOP Eqpt = 3093 psi - (.22 psi/ft x 6958') = 1562 psi

Tom
1 Sep 2011

8/15

5. Proposed Wellhead Program:

The wellhead equipment will be suitable for H_2S service.

We propose to use a Woodgroup S95 11" 5M casing head and T-S95 7-1/16" 10M Tubing Head, Material Class DD-NL, Temperature Class P.

We also propose that we have the option to use the following standard / conventional wellhead as an option:

- Casing Head: 8-5/8" Slip on and Weld x 11" 5M Casing Head, API 6A, Material Class DD-NL, Temperature Class P, installed on 8-5/8" surface casing.
- Tubing Head: 11" 5M x 7-1/6" 10M Tubing Head, API 6A, Material Class DD-NL, Temperature Class P, installed after setting 5-1/2" production casing

6. 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
0 – Surface Casing Point	Fresh Water or Fresh Water Native Mud	8.5 – 9.0	28 – 40	N.C.	N.C.
Surface Casing Point to TD	Brine (Saturated $NaCl_2$)	10	29	N.C.	10 - 11
Conversion to Mud at TD	Brine Based Mud ($NaCl_2$)	10	34 – 45	5 – 10	10 - 11

12-1/4" hole from surface of ground to surface casing point: The circulating media will be either a native mud or fresh water with high viscosity sweeps. The mud components will be:

- Fresh Water
- Bentonite (if needed)
- Lime
- Soda Ash
- Starch (if needed)
- Drilling Paper
- Other loss of circulation material if needed (nut plug or fiberous material)
- Soap sticks (if needed)

7-7/8" hole from the surface casing shoe to TD: The circulating media will be 10 ppg saturated $NaCl_2$ brine and will be converted to a mud with starch, attapulgite, lime, and asphalt for additional fluid loss control if needed upon reaching Total Depth (TD). The mud components will be:

- Brine (approximately 10 lb/gal density, saturated $NaCl_2$)
- Attapulgite
- Lime
- Starch
- Asphalt (if needed for additional fluid loss control)
- Drilling Paper, Walnut Hulls, and Fiberous LCM material such as BaroSeal if needed
- Soap Sticks if needed
- Lease crude oil or diesel with Pipe-Lax or EZ-Spot as a spotting fluid if needed in the event of differential sticking

TMM 1 Sep 2011

Drilling mud containing H2S shall be degassed in accordance with API RP-49, item 5.14. The gases shall be piped into the flare system.

Sufficient quantities of mud additives shall be maintained on location to scavenge and/or neutralize H2S. We will inject into our flow stream while circulating from the corrosion trailer we have from Baroid ~10 gpd BaraScav L, SI-430, Baracor 100, and DA3-20 to scavenge H2S and to protect the tubulars from corrosion. No barite or other weighting material will be on location.

7. **Logging, Coring, and Testing Program:**
   a. No drill stem tests will be done
   b. No mud logging is planned, but might possibly be done if it is determined that this data is needed;
   c. No whole cores are planned
   d. The open hole electrical logging program is planned to be as follows:
      - Total Depth to 2500': Resistivity, Density, and Gamma Ray.
      - Total Depth to surface Casing Shoe: Caliper
      - Total Depth to surface, Gamma Ray and Neutron
      - Formation pressure data (XPT) on electric line if needed (optional)
      - Rotary Sidewall Cores on electric line if needed (optional)
      - BHC or Dipole Sonic if needed (optional)
      - Spectral Gamma Ray if needed (optional)

8. **Abnormal Pressures and Temperatures:**

- We do not expect to encounter any abnormal pressures or abnormally pressured horizons.

- The expected Bottom Hole Temperature is 113 degrees F.

- 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 8.5 ppg gradient. The calculation of Required Working Pressure for the BOP Equipment is presented below:
  - Required Working Pressure for BOP Eqpt = (8.5 x .052 x 7200) - (.22 psi/ft x 7200)
  - Required Working Pressure for BOP Eqpt = 3182 - (.22 psi/ft x 7200) = 1598 psi

- 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
Seven Rivers (Eumont)	30,000	100	200	92
San Andres	33,000	30	100	46
Yeso Group	1000	300	47	22

ConocoPhillips will comply with the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations and will provide H_2S monitoring equipment which will be rigged up, tested, and operational prior to drilling out from surface casing.

All persons arriving on location will have H_2S certification & training that occurred within the last year.

Each occurrence of H_2S gas at surface is to be noted on the daily reports and any occurrence of H_2S in excess of 100 ppm will be reported to the authorized officer as soon as possible but no later than the next business day per the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations.

ConocoPhillips will provide an H_2S Contingency Plan and will keep this plan updated and posted at the wellsite during drilling operations.

All equipment that has the potential to be exposed to H_2S will be suitable for H_2S service.

1 Sep 2011

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

Road and location construction will begin after the BLM and NMOCD have approved the APD and will take into account any closure stipulations that may be attached or specified in order to avoid operations in any closure period. Also, rig availability may impact our schedule. With consideration of these limiting factors, we would intend / plan to drill this well within two years after receiving approval of the APD.

Attachments:

- Attachment # 1........Proposed Casing and Cementing Program
- Attachment # 2........Diagram of Choke Manifold Equipment (Excerpted from 54 FR 39528, Sept 27, 1989)
- Attachment # 3........BOP and Choke Manifold Schematic – 2M System (Figure 3-1, Appendix G, from BLM)
- Attachment # 4........BOP and Choke Manifold Schematic – 2M System (Figure 3-1A, Appendix G, from BLM)

Contact Information:

Program prepared by:
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Date: June 28, 2011

Tom M
1 Sep 2011

ConocoPhillips

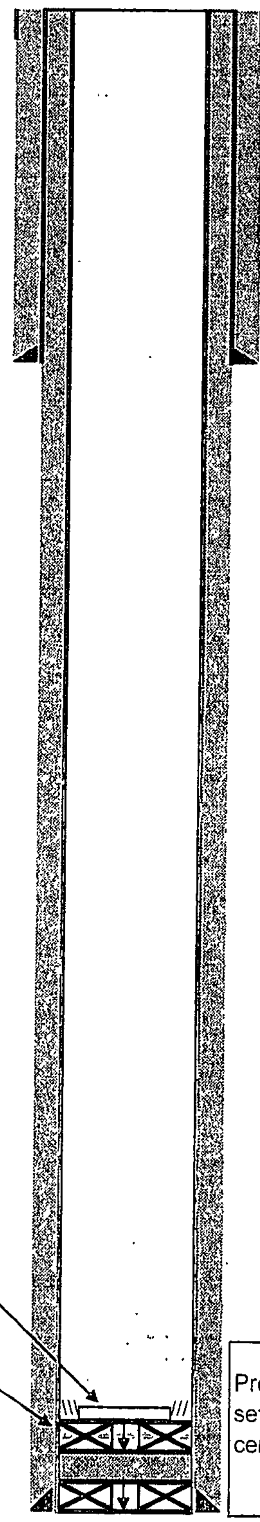
Attachment # 1

Proposed Casing & Cementing Program

398

Datum: RKB (14' above ground level)

Conductor: 13-3/8" 48# H-40 casing or 16" x ½" wall Grade B Line Pipe Set 30' to 85' below ground level (44' to 99' MD RKB) in 20" hole and cemented to surface.



Surface Casing: 8-5/8" 24# J-55 ST&C set at least 25' into the Rustler formation and above the salt in 12-1/4" hole and cemented single-stage to surface..

TMM 1 Sep 2011

Cement Wiper Plug

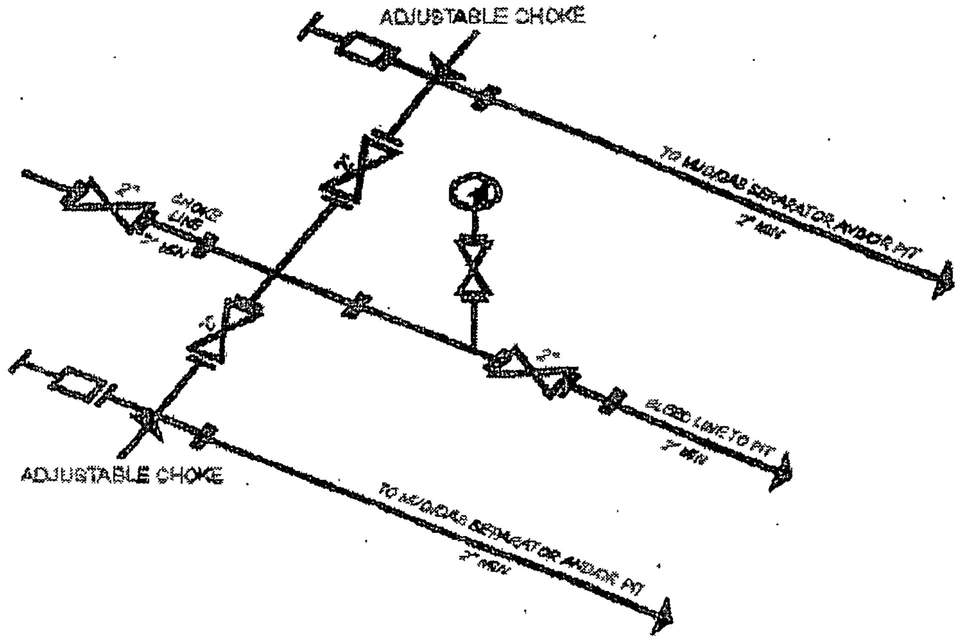
Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# L-80 LT&C set 10' above TD in 7-7/8" hole and cemented single -stage to surface

Schematic prepared by:
Steven O Moore, Staff Drilling Engineer
28-June-2011

Attachment #:2

Attachment I. Diagrams of Choke Manifold Equipment



2M CHOKE MANIFOLD EQUIPMENT - CONFIGURATION OF CHOKES MAY VARY

1 Sep 2011

Attachment # 3

2000 psi System

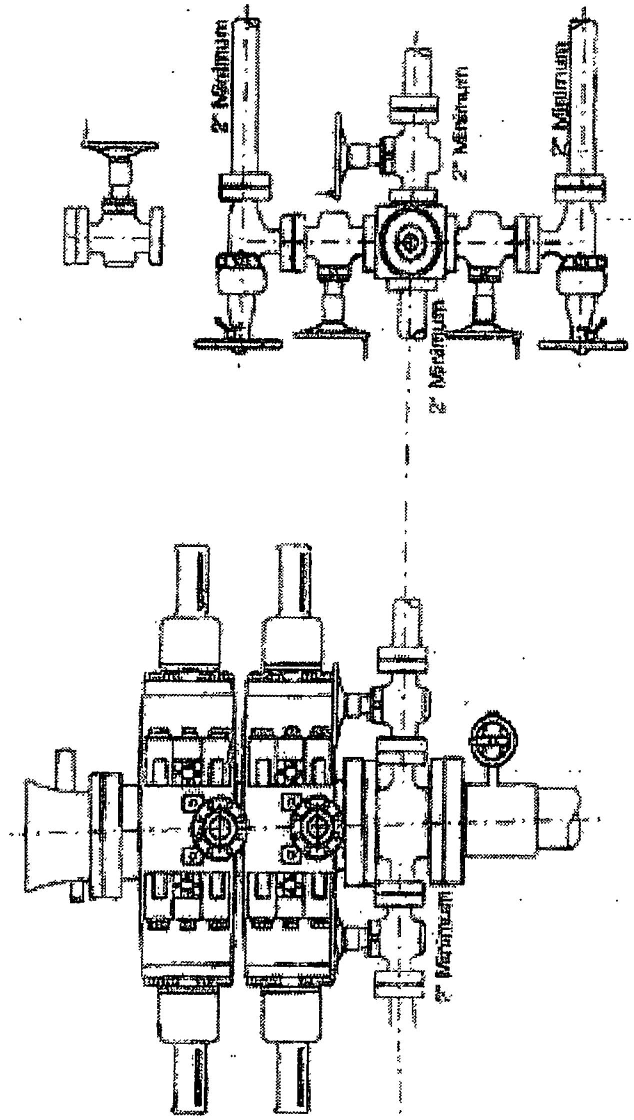


Figure 3-1

Appendix G

Attachment # 4

2000 psi System

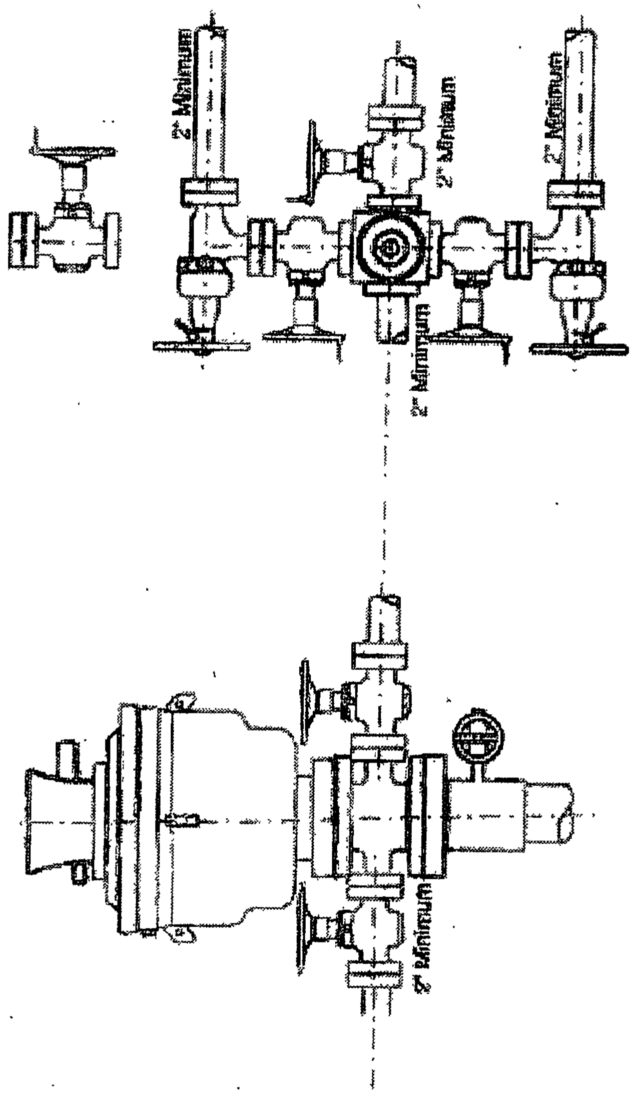
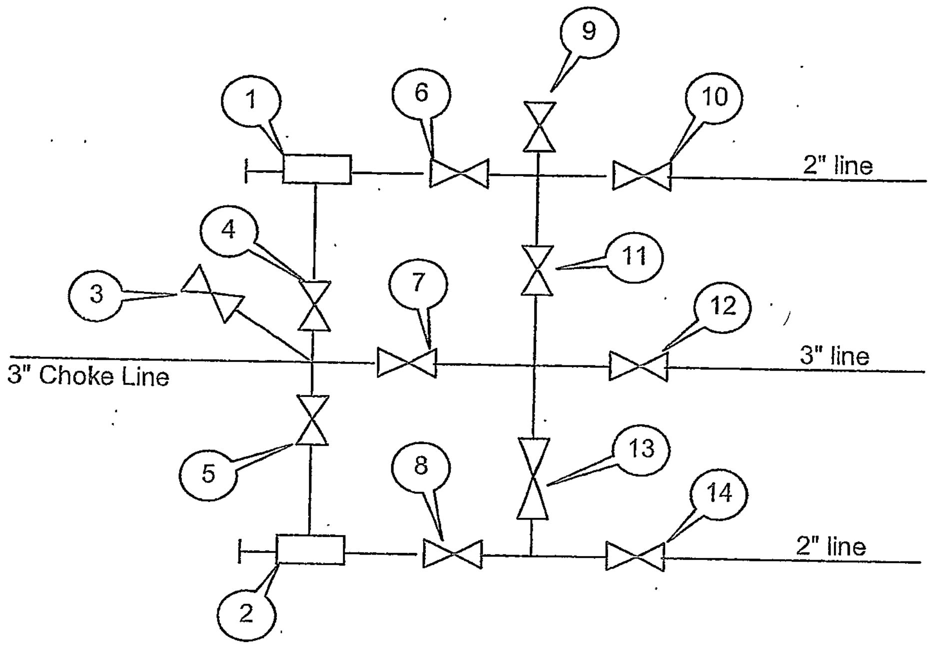


Figure 3-1A

Appendix G

CHOKE MANIFOLD ARRANGEMENT



Item	Description
1	Manual Adjustable Choke, 2-1/16", 5M
2	Manual Adjustable Choke, 2-1/16", 5M
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, 2-1/16" 5M
12	Gate Valve, 3-1/8" 3M
13	Gate Valve, 2-1/16" 5M
14	Gate Valve, 2-1/16" 5M

Drawn by:
Steven O. Moore
Chief Drilling Engineer, Mid-Continent Business Unit, ConocoPhillips Company
Date: 12-July-2011

13/15