District I
1625 N. French Dr., Hobbs, NM 88240
District II
1301 W. Grand Avenue, Artesia, NM 88210
District III
1000 Rio Brazos Road, Aztec, NM 87410
District IV
1220 S. St. Francis Dr., Santa Fe, NM 87505

State of New Mexico
Energy Minerals and Natural Resources

Oil Conservation Division
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-101
May 27, 2004

Submit to appropriate District Office

☐ AMENDED REPORT

APPLICATION FOR PERMIT TO DRILL, RE-ENTER, DEEPEN, PLUGBACK, OR ADD A ZONE

[1] Operator Name and Address	[2] OGRID Number
ConocoPhillips Company 4001 Penbrook St. Odessa, TX 79762	217817
	[3] API Number 30-025-33677

[4] Property Code	[5] Property Name	[6] Well No.
32479	Deck Estate 7	1

[9] Proposed Pool 1	[10] Proposed Pool 2
Blinebry Oil & Gas (06660)	Hardy (Tubb Drinkard)

[7] Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
L	7	21S	37E		1930	South	990	West	Lea

[8] Proposed Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County

Additional Well Information

[11] Work Type Code	[12] Well Type Code	[13] Cable/Rotary	[14] Lease Type Code	[15] Ground Level Elevation
E	O	R	P	3490'
[16] Multiple	**[17] Proposed Depth**	**[18] Formation**	**[19] Contractor**	**[20] Spud Date**
No	10,100	Blinebry/Drinkard		01/01/2004

Depth to Groundwater	Distance from nearest fresh water well	Distance from nearest surface water

Pit: Liner: Synthetic ☐ ____ mils thick Clay ☐ Pit Volume: ____ bbls Drilling Method:
Closed-Loop System ☐ Fresh Water ☐ Brine ☐ Diesel/Oil-based ☐ Gas/Air ☐

[21] Proposed Casing and Cement Program

Hole Size	Casing Size	Casing weight/foot	Setting Depth	Sacks of Cement	Estimated TOC
17-1/2"	K-55, 13-3/8"	54.5#	435'	455	Surface
12-1/4"	J-55, 8-5/8"	32#	3986'	1900	Surface
7-7/8"	L-80&K-55,5-1/2"	17#	10,100'	835	TOC @3886'

[22] Describe the proposed program. If this application is to DEEPEN or PLUG BACK, give the data on the present productive zone and proposed new productive zone. Describe the blowout prevention program, if any. Use additional sheets if necessary.

ConocoPhillips proposes to recomplete this well to the Blinebry using the attached procedure. The well will then be downhole commingled with Blinebry/ Drinkard production.

Permit Expires 1 Year From Approval
Date Unless ~~Drilling Underway~~
Re-Entry

OCT 2004
RECEIVED
Hobbs
OCD

[23] I hereby certify that the information given above is true and complete to the best of my knowledge and belief. **I further certify that the drilling pit will be constructed according to NMOCD guidelines ☐, a general permit ☐, or an (attached) alternative OCD-approved plan ☐.**

Kay Maddox

Printed name: Kay Maddox
Title: Regulatory Agent
E-mail Address:
Date: 10/15/2004 Phone: (915)368-1207

OIL CONSERVATION DIVISION

Approved by: PETROLEUM ENGINEER
Title:
Approval Date: OCT 20 2004 Expiration Date:
Conditions of Approval Attached ☐

ConocoPhillips

DECK ESTATE "7" #1
Blinebry Recompletion & Downhole Commingle Procedure

Location: 1930' FSL & 990' FWL, Sec 7, T-21-S, R-37-E, Lea Co. New Mexico
AFE #:
AFE Amount: $000,000 Gross / Net
Spud Date: 12/17/96
API Number: 30025 - 3367700
Proposed Zone/Pool: Drinkard / Hardy Tubb-Drinkard Pool
Battery Destination: New Battery

TD: 7176' Driller's Depth
PBTD: Surface
DV Tools: 7725'

KBE: 3504.6'
GLE: 3490'
KBM: 14.6' above GL

Existing Casing Program

Hole Size (in)	Csg Size (in)	Depth (ft)	Wt (lb/ft)	Grade	Conn	ID	Burst (psi)	Coll * (psi)	Ten (Klbs)	Rated by
17-1/2	13-3/8	435	54.5	K-55	ST&C	12.615	2730	1130	547	API
12-1/4	8-5/8	3986	32	J-55	LT&C	7.921	3930	2530	417	API
7-7/8	5-1/2	0 – 646	17	L-80	LT&C	4.892	7740	6280	348	API
7-7/8	5-1/2	646 – 9243	17	K-55	LT&C	4.892	5320	4910	272	API
7-7/8	5-1/2	9243 – 10,100	17	L-80	LT&C	4.892	7740	6280	348	API

Project Overview:

The proposed Blinebry recompletion will consist of pulling the existing downhole equipment from the well, setting a RBP above the Drinkard completion, perforating and sand fracturing the Blinebry interval from 5659' to 5665' and placing the well back on production in the Blinebry for 30 to 60 days to establish a stable production rate. Once the Blinebry production has stabilized the well will be pulled and the RBP retrieved and both the Drinkard and Blinebry will be downhole commingled.

The Deck Estate 7 No. 1 is currently producing from the Drinkard at a rate of 6 BOPD, 15 BWPD and 140 MCFGPD. The Blinebry recompletion is expected to add an approximate 35 BOPD and 135 MCFGPD which when commingled would be approximately 40 to 50 BOPD and 300 MCFGPD. Additional water production could be added if the Blinebry fracture treatment extends down into the lower Blinebry intervals.

Existing & Squeezed Perforations:

San Andres: **Cement Squeezed:** 4018, 25, 32, 34, 70, 74, 90, 4124, 27, 31, 36, 40, 46, 50, 57 (15 Holes Total)

Glorieta: **Cement Squeezed:** 5208, 14, 24, 31, 33, 53, 54, 56, 72, 74, 76, 80, 92, 95, 98 (16 Holes Total)

L. Glorieta: **Cement Squeezed:** 5573,. 75, 78, 80, 92 94 (6 Holes Total)

Drinkard: 6784' to 6789' (Total 75 Holes)
6792' to 6800'
6828' to 6834'

Proposed Blinebry Perforations:

Blinebry: 5659' to 5665' (6' NEP, Total Holes 25)

Well Control Requirements:

Well Control: Well Control equipment and procedures will be in accordance with the ConocoPhillips Well Control Manual, Second Edition, Revision Two, dated August 1994.

Well Category: All zones encountered in the well are normally pressured. Since 9.5 ppg kill fluid will be used throughout the procedure the well is not anticipated to flow at any time during the operation. This well is to be considered a **Category 2** well due to expected flow rates exceeding 300 MCFGPD from the Blinebry completion after it is stimulated and unloaded. **Category 2** wells normally require two untested barriers, however the Hobbs area has been granted an exception, allowing the use of one untested barrier. Approval has been granted for use of a dynamic fluid column as that barrier.

BOPE Class 2: For operations the MPSP for this well is estimated to be in the range of 1000 PSIG to 2000 PSIG. A **Class 2 BOP** stack is required. The actual stack will exceed the Class 2 requirement and will consist of a hydraulic operated 5M PSIG BOP stack with tubing rams on top and a blind ram on bottom. NU shop tested BOP stack on top of companion flange. Test as per SOP.

Workover Fluid: Use treated 9.5 ppg brine water for duration of operations. Use dynamic head kill procedure if required to maintain control of the well during tripping and installation / removal of BOP's.

Wellhead Program:

Casing Head:	8-5/8" SOW x 11" 3M
Tubing Head:	11' 3M WP X 7 1/16" 5M WP
Tubing Head Adaptor:	B-1 Adapter Flange
Type 3 Beam Pump Wellhead:	See Attached Sketch (Contains Choke on Casing)

Drinkard / Blinebry Artificial Lift Specs:
(See attached beam pump design for additional information)

PU Specs: Existing Lufkin C320 – 000 – 120
Tubing: 2 7/8" L-80 (Existing)
Rod String: Existing Tapered 7/6 Class KD (2250" of 7/8" Rods + 4450' of ¾" Rods)
Rod Pump: 25-150-RHBC 20-6-00 2 Stage HVR Type "A" (Corrosive environment with gas interference)
Stroke Length: 85"
PU Speed: 10 SPM

Wellbore Prep Procedure:

Note: All depths referenced to 14.6' RKB.

1. RU pulling. Hook up water transport to the casing and kill well with 100 bbls of 9.5 ppg treated brine water. Use dynamic head kill procedure during installation / removal of BOP stack and tripping, if necessary.

2. TOOH with 2250' of 7/8" KD rods and 4450' of ¾" KD rods with 6, 1.5" K bars. Visually inspect rods for worn couplings and pitting. Lay down any worn or pitted rods. Also lay down an additional -----' of ¾" rods to allow for pump testing the shallower Blinebry for 30 to 60 days.

3. NU 5,000 PSIG WP hydraulic operated BOPE and test to 250/5000 PSIG. TOOH with the 2 7/8" L-80 production tubing. TAC set at approximately 6677' with SN at approximately 6892'.

4. If significant scale or paraffin is found on the outside of the tubing PU 4 ¾" bit and scraper and TIH to approximately 6,000'. PU 5½" RBP (no ball catcher) and treating packer and TIH to set the plug at +/- 5750' (85' below the proposed Blinebry interval 5659' to 5665'). After setting the plug PU 1 joint and set the packer. Load the tubing and pressure test the plug to 4,000 PSIG. Dump 2 sks of sand on top of the RBP.

5. Release the packer and PU to 5680'. RU pump truck and spot 500 gals of 15% NEFE HCL across the proposed Blinebry perforations from 5659' to 5665'. TOOH laying down the production tubing and packer.

6. RU Schlumberger electric line services. Install lubricator and pressure test to 1,000 PSIG against the blind rams. RIH with GR/CCL and 4" OD HEGS non-ported casing guns loaded 4 SPF in 120 degree phasing to perforate the following Blinebry interval. **Note: Correlate the perforating gun using the Wedge CBL log dated Jan 1997.** The gun charge is a 22.7-gram charge to provide 0.42" perforation ID hole with 21" of penetration.

	Interval	NEP	Shots
Blinebry	**5659' to 5665'**	**6'**	**25 Holes**

7. PU 5620' of 2 7/8" N-80 workstring with a CS1 10 M treating packer, or equivalent. Hydro-test each stand to 7,000 PSIG while tripping. TIH and space out to set the packer 5620' (39' above the top Blinebry perforation at 5659' and 26' below the bottom squeezed perforation at 5594'). Land the tubing in the tubing head using an extended neck hanger with a 10,000 PSIG WP upper seal section.

8. Install a BPV and ND the BOP stack. NU a 10,000 WP Frac tree (See attached wellhead configuration sketch). Test the tubing head adaptor flange to 5,000 PSIG. Remove the BPV.

9. RU Schlumberger treating services. Install 10 M PSIG WP frac valve on the frac tree. Install treating line with nitrogen actuated relief valve. Test the tree and treating line to 6000 PSIG and set the relief valve at 5300 PSIG. Lay a staked relief line from the casing to an open frac tank. Install a second relief valve on the casing relief line set to relieve at 1,500 PSIG. Load the casing and pressure up to 500 PSIG and monitor for potential breakthrough during the frac job. Pump the acid breakdown and the sand frac as per the attached Schlumberger recommendation. Do not exceed 4800 PSIG treating pressure.

TREATING LINE TEST PRESSURE: A minimum 1000 psig over MATP	**6000**	**PSIG**
MAXIMUM ALLOWABLE WORKING PRESSURE: Based on weakest component in system. Burst pressure of 5 1/2" casing.	**5300**	**PSIG**
NITROGEN POP OFF SET PRESSURE: Relief pressure set at the lesser of : 300 psig less than 90% MAWP or, 300 psig over MATP	**5300**	**PSIG**
MAXIMUM ALLOWABLE TREATING PRESSURE: If reached, human action required.	**4800**	**PSIG**
MAXIMUM ANTICIPATED TREATING PRESSURE:	**4800**	**PSIG**

Acid Breakdown:

- Load tubing and initialize breakdown with 50 bbls of 2% KCL slick water
- Pump 1,500 gals of 15% NEFE HCL acid at 3 – 5 BPM containing 50 1.3 SG, 7/8" RCN ball sealers.
- Overdisplace breakdown with 50 bbls of 2% KCL slick water.
- Surge balls off perforatons.

Frac Treatment Leakoff Test:

- Load tubing and pump 20 bbls of frac fluid at 6 BPM
- Pump an additional 20 bbls of frac fluid at 12 BPM
- Pump an additional 60 bbls of frac fluid at 18 BPM
- Shut down and determine fluid efficiency. Verify that there is no communication from the Blinebry perforations to the backside of the packer via squeeze perforations at 5573' to 5594'.

Frac Treatment:

- Load tubing and pump 10,000 gals (238 bbls) YF130ST pad at 18 BPM
- Pump 2,000 gals (48 bbls) YF125ST fluid with 2.0 ppg 20/40 Brady Sand at 18 BPM
- Pump 2,000 gals (48 bbls) YF125ST fluid with 3.0 ppg 20/40 Brady Sand at 18 BPM
- Pump 2,000 gals (48 bbls) YF125ST fluid with 4.0 ppg 20/40 Brady Sand at 18 BPM
- Pump 2,000 gals (48 bbls) YF125ST fluid with 5.0 ppg 20/40 CR 4000 at 18 BPM
- Pump 2,000 gals (48 bbls) YF125ST fluid with 6.0 ppg 20/40 CR 4000 at 18 BPM
- Flush with 1,331 gals (32 bbls) WF100 fluid at 18 BPM
- Shut down and record leakoff until fracture closure.

8. RD Schlumberger pumping services. Leave the well shut-in a minuimum of 12 hours. Flow back the well until it dies.

9. Install the BPV and ND the treating tree. NU the BOP stack and conduct BOP test as per SOP. Remove the BPV.

10. Release the packer and TOOH with the tubing and packer. PU 4 3/4 bladed bit and TIH to clean out resin coated sand to the top of the RBP. TOOH with bit laying down the workstring.

11. TIH with approximately 5,690' of 2 7/8", L-55 production tubing with the open ended SN on bottom of the tubing and a 5 ½" TAC. The bottom joint to be polylinned. Space the tubing out to set the seating nipple at approximately 5,690' (or 25' below the bottom Blinebry perforation with the TAC at approximately 5,620' (38' above the top Blinebry perforation).

12. ND the BOP stack and install the B-1 adapter flange. Pump corrosion inhibitor down the tubing to coat the rods and pump as they are run in the hole. PU standard strainer nipple on the bottom of the 25-150-RHBC 20-6-00 2 Stage HVR Type "A" pump on 7/6 KD "Existing" rod string and RIH to place on beam pump. **(See attached Blinebry Beam Pump Design.** RD and move off.

13. Notify Champion prior to placing the well on production. As soon as the well is started have it placed on scheduled CI truck treatments. **Schedule a backside scale squeeze as soon as the fluid level is pumped off.**

14. Operator to submit a change of status form for new production. Report daily well tests and fluid levels to the Midland office for 30 days or until it pumps off and the production rate has stabilized.

Downhole Commingle: Downhole commingle to be done sometime following 30 to 60 days of stabilized production.

15. **After 30 to 60 days of testing the Blinebry and receiving approval to commingle the Drinkard & Blinebry**. RU workover rig. Pump 100 bbls of 9.0 ppg treated brine water down casing to kill the well. Unseat the pump and POOH with 7/6 KD rod string. Inspect for rod and coupling wear. Replace any pitted rods or worn couplings. Notify Champion if any corrosion or pitting is noticed on the rods.

16. Remove the pumping head and install the 5,000 PSIG BOP stack. Test the BOP's to as per SOP. TOOH with 2 7/8" tubing. Visually inspect tubing for corrosion pitting. Notify Champion if any corrosion or pitting is noticed on the tubing.

17. PU retrieving head for 5 ½" loc-set RBP and TIH to retrieve RBP set at 5,750'. Release the RBP and TOOH with tubing and plug.

18. TIH with approximately 6,810' of 2 7/8", L-55 production tubing with the open ended SN on bottom of the tubing and a 5 ½" TAC. The bottom joint to be polylinned. Space the tubing out to set the seating nipple at approximately 6,810' (20' below the bottom Drinkard perforation with the TAC at approximately 5,620' (38' above the top Blinebry perforation).

19 ND the BOP stack and install the B-1 adapter flange. Pump corrosion inhibitor down the tubing to coat the rods and pump as they are run in the hole. PU standard strainer nipple on the bottom of the 25-150-RHBC 20-6-00 2 Stage HVR Type "A" pump on 7/6 KD "Existing" rod string and RIH to place on beam pump. **(See attached Drinkard / Blinebry Beam Pump Design.** RD and move off.

20. Notify Champion prior to placing the well on production. As soon as the well is started have it placed on scheduled CI truck treatments. **Collect water sample and determine if a backside scale squeeze should be scheduled.**

21 Operator to submit a change of status form for new production. Report daily well tests and fluid levels to the Midland office for 30 days or until it pumps off and the production rate has stabilized.

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State of New Mexico
Energy, Minerals & Natural Resources Department
OIL CONSERVATION DIVISION
1220 South St. Francis Dr.
Santa Fe, NM 87505

Form C-102
Revised June 10, 2003
Submit to Appropriate District Office
State Lease - 4 Copies
Fee Lease - 3 Copies

☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

1 API Number	2 Pool Code	3 Pool Name
30-025-33677	06660	Blinebry Oil and Gas

4 Property Code	5 Property Name	6 Well Number
~~19955~~ 32479	Deck Estate 7	1

7 OGRID No.	8 Operator Name	9 Elevation
217817	ConocoPhillips Company	3490

10 Surface Location

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
L	7	21S	37E		1930	South	990	West	Lea

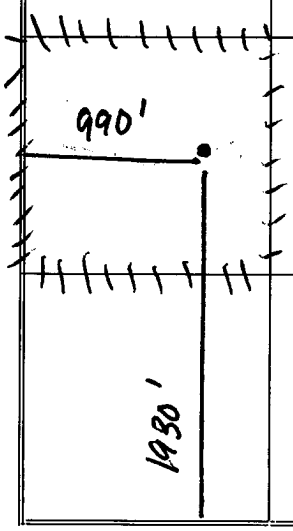
11 Bottom Hole Location If Different From Surface

UL or lot no.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County

12 Dedicated Acres	13 Joint or Infill	14 Consolidation Code	15 Order No.
40			

NO ALLOWABLE WILL BE ASSIGNED TO THIS COMPLETION UNTIL ALL INTERESTS HAVE BEEN CONSOLIDATED OR A NON-STANDARD UNIT HAS BEEN APPROVED BY THE DIVISION

16



17 OPERATOR CERTIFICATION

I hereby certify that the information contained herein is true and complete to the best of my knowledge and belief.

Signature: Kay Maddox

Kay Maddox
Printed Name

Regulatory Agent
Title and E-mail Address

10/15/2004
Date

18 SURVEYOR CERTIFICATION

I hereby certify that the well location shown on this plat was plotted from field notes of actual surveys made by me or under my supervision, and that the same is true and correct to the best of my belief.

Date of Survey

Signature and Seal of Professional Surveyor:

Certificate Number