ATS-08-355

Form 3160-3
(April 2004)

OCD-HOBBS

FORM APPROVED
OMB No. 1004-0137
Expires March 31, 2007

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

	5. Lease Serial No. 5A-08-631 LC-058697B
	6. If Indian, Allotee or Tribe Name
1a. Type of work: [X] DRILL [ ] REENTER	7. If Unit or CA Agreement, Name and No.
1b. Type of Well: [X] Oil Well [ ] Gas Well [ ] Other [ ] Single Zone [ ] Multiple Zone	8. Lease Name and Well No. <31422> MCA Unit 391
2. Name of Operator ConocoPhillips Company <217817>	9. API Well No. 30-025- 38853
3a. Address 3300 N. "A" Street, Bldg. 6 Midland, TX 79705 / 3b. Phone No (include area code) (432)688-6884	10. Field and Pool, or Exploratory Maljamar; Grayburg-San Andres
4. Location of Well (Report location clearly and in accordance with any State requirements.*) At surface 2622' FNL & 662' FEL, Sec. 25, T-17-S, R-32-E, UL "H" At proposed prod. zone 2622' FNL & 662' FEL, Sec. 25, T-17-S, R-32-E, UL "H"	11. Sec., T. R. M. or Blk. and Survey or Area H Sec: 25 Twn:17S Rng: 32E

14. Distance in miles and direction from nearest town or post office*	12. County or Parish	13. State
Approximately 4.5 miles south from Maljamar, NM	Lea	New Mexico

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any)	16. No. of acres in lease	17. Spacing Unit dedicated to this well
2622' North & 3302' East	13,786.66	40

18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft.	19. Proposed Depth	20. BLM/BIA Bond No. on file
642' S from #137	4490'	ES0085

21. Elevations (Show whether DF, KDB, RT, GL, etc.)	22. Approximate date work will start*	23. Estimated duration
4013' GR	06/01/2008	8 Days

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, shall 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 shall 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 authorized officer.

25. Signature	Name (Printed/Typed)	Date
Celeste H. Dale	Celeste G. Dale	01/21/2008
Title: Regulatory Specialist		
Approved by (Signature) /s/ Don Peterson	Name (Printed/Typed) /s/ Don Peterson	Date APR 0 9 2008
Title FOR 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.

RECEIVED

*(Instructions on page 2)

APR 1 1 2008

LEA COUNTY CONTROLLED WATER BASIN

HOBBS OCD

APPROVAL SUBJECT TO GENERAL REQUIREMENTS AND SPECIAL STIPULATIONS ATTACHED

SEE ATTACHED FOR CONDITIONS OF APPROVAL

DISTRICT I 1625 N. French Dr., Hobbs, NM 88240 DISTRICT II 1301 W. Grand Avenue, Artesia, NM 88210 DISTRICT III 1000 Rio Brazos Rd., Aztec, NM 87410 DISTRICT IV 1220 S. St. Francis Dr., Santa Fe, NM 87505	State of New Mexico Energy, Minerals & Natural Resources Department OIL CONSERVATION DIVISION 1220 South St. Frances Dr. Santa Fe, NM 87505	Form C-102 Revised October 12, 2005 Submit to Appropriate District Office State Lease - 4 Copies Fee Lease - 3 Copies ☐ AMENDED REPORT

WELL LOCATION AND ACREAGE DEDICATION PLAT

API Number	Pool Code	Pool Name
30-025-38853	43329	Maljamar; Grayburg-San Andres

Property Code	Property Name	Well Number
31422	MCA UNIT	391

OGRID No.	Operator Name	Elevation
217817	CONOCOPHILLIPS COMPANY	4013'

Surface Location

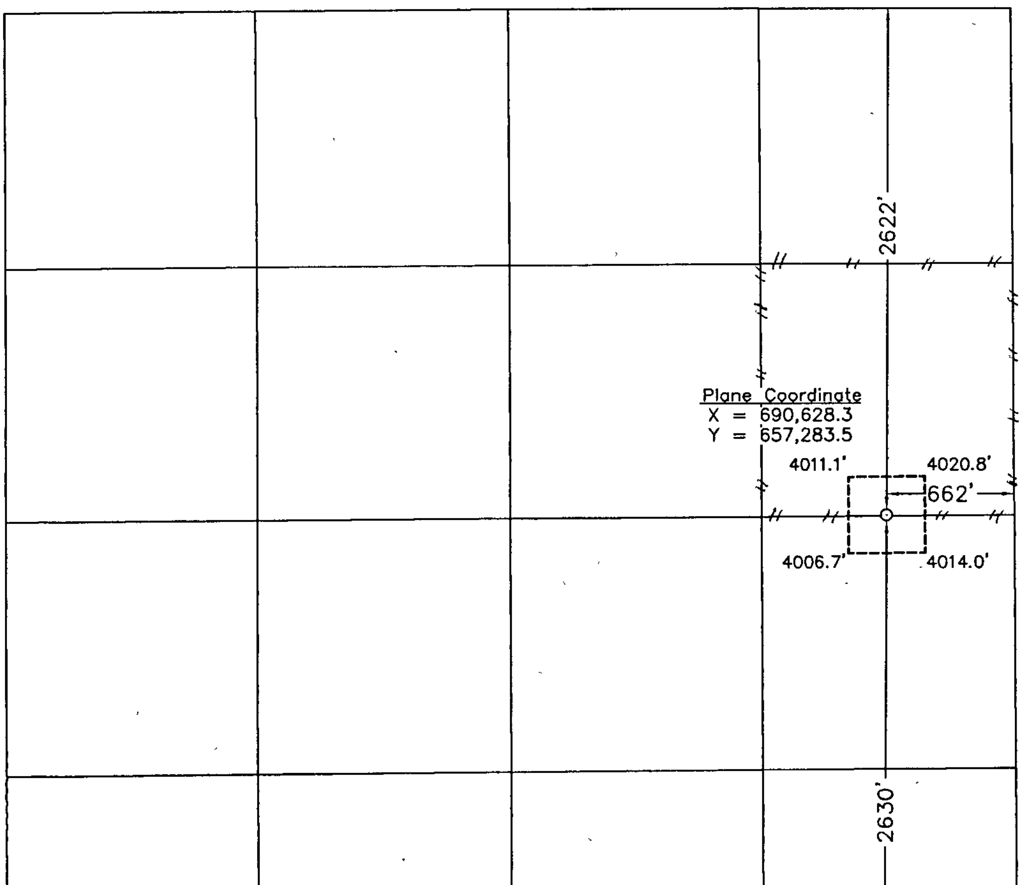
UL or lot No.	Section	Township	Range	Lot Idn	Feet from the	North/South line	Feet from the	East/West line	County
H	25	17 S	32 E		2622	NORTH	662	EAST	LEA

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

Dedicated Acres	Joint or Infill	Consolidation Code	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



NOTE:

1) Plane Coordinates shown hereon are Transverse Mercator Grid and Conform to the "New Mexico Coordinate System", New Mexico East Zone, North American Datum of 1927. Distances shown hereon are mean horizontal surface values.

OPERATOR CERTIFICATION

I hereby certify the the information contained herein is true and complete to the best of my knowledge and belief, and that this organization either owns a working interest or unleased mineral interestin the land including the proposed bottom hole location or has a right to drill this well at this location pursuant to a contract with an owner of such a mineral or working interest, or to a voluntary pooling agreement or a compulsory pooling order heretofore entered by the division.

01/31/08

Signature Date

Celeste G. Dale

Printed Name

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 supervison and that the same is true and correct to the best of my belief

June 15, 2007

Date of Survey

Signature & Seal of Professional Surveyor

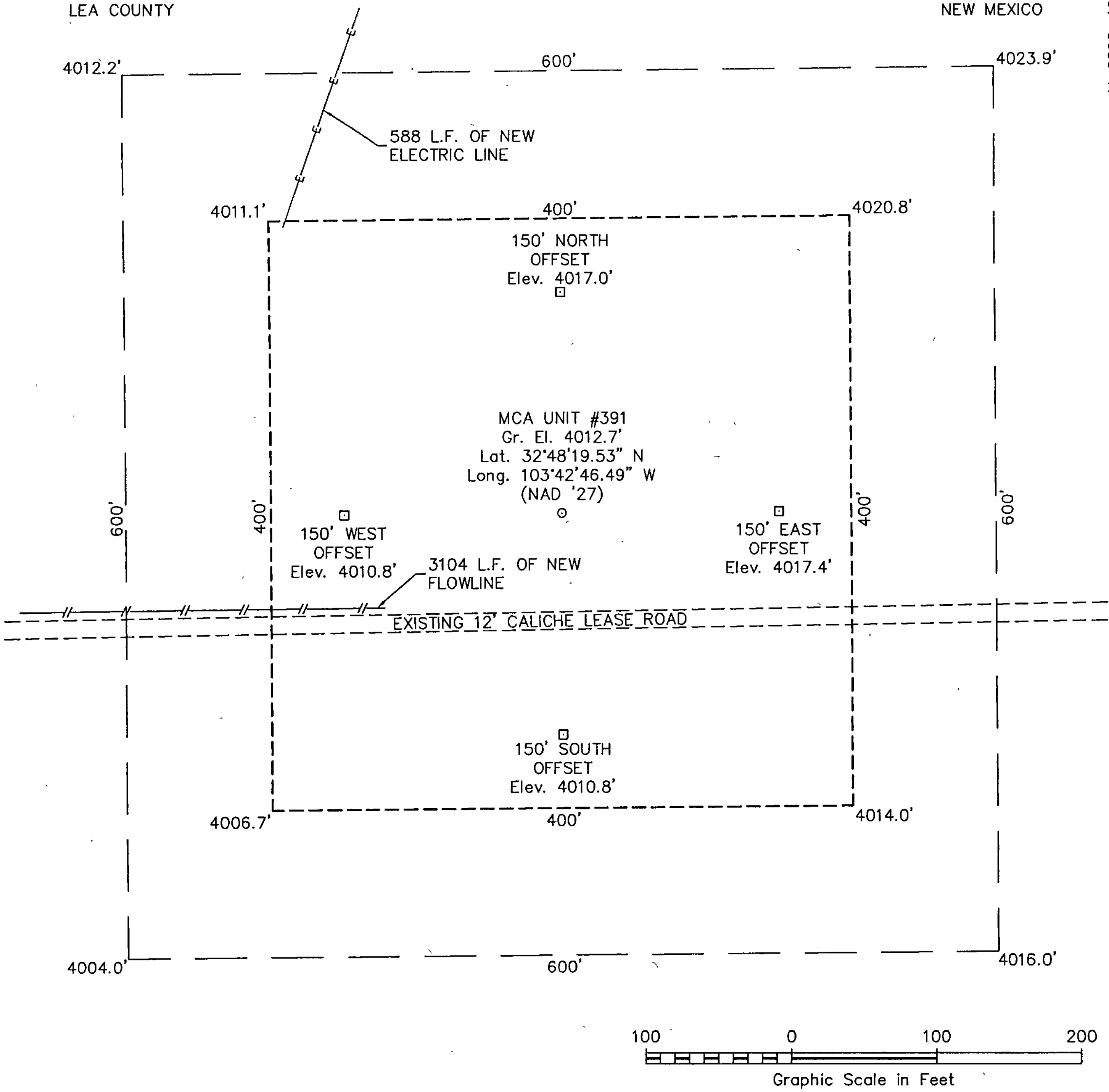
W.O. Num. 2007-0639 LVA

Certificate No. MACON McDONALD 12185

SECTION 25, TOWNSHIP 17 SOUTH, RANGE 32 EAST, N.M.P.M.

L-2007-0639-A

LEA COUNTY NEW MEXICO



DRIVING DIRECTIONS

FROM THE INTERSECTION OF STATE HIGHWAY 529 AND STATE HIGHWAY 33 4.5 MILES SOUTH OF MALJAMAR, NM GO NORTH ON SAID STATE HIGHWAY 33, 1.7 MILES TO A LEASE ROAD ON THE RIGHT (EAST) SIDE OF SAID HIGHWAY, THEN GO EAST ALONG SAID LEASE ROAD 2.1 MILES TO A CURVE TO THE RIGHT (SOUTH-SOUTHEAST), THEN GO SOUTH-SOUTHEAST APPROXIMATELY 0.4 MILE TO A LEASE ROAD ON THE RIGHT (SOUTH) SIDE OF ROAD, THEN GO SOUTH APPROXIMATELY 0.3 MILE TO A LEASE ROAD ON LEFT (EAST) SIDE OF ROAD, THEN GO EAST APPROXIMATLEY 0.2 MILE TO A POINT BEING 75 FEET SOUTH OF THE PROPOSED LOCATION.

WEST COMPANY of Midland, Inc.

110 W. LOUISIANA, STE. 110
MIDLAND TEXAS, 79701
(432) 687-0865 - (432) 687-0868 FAX

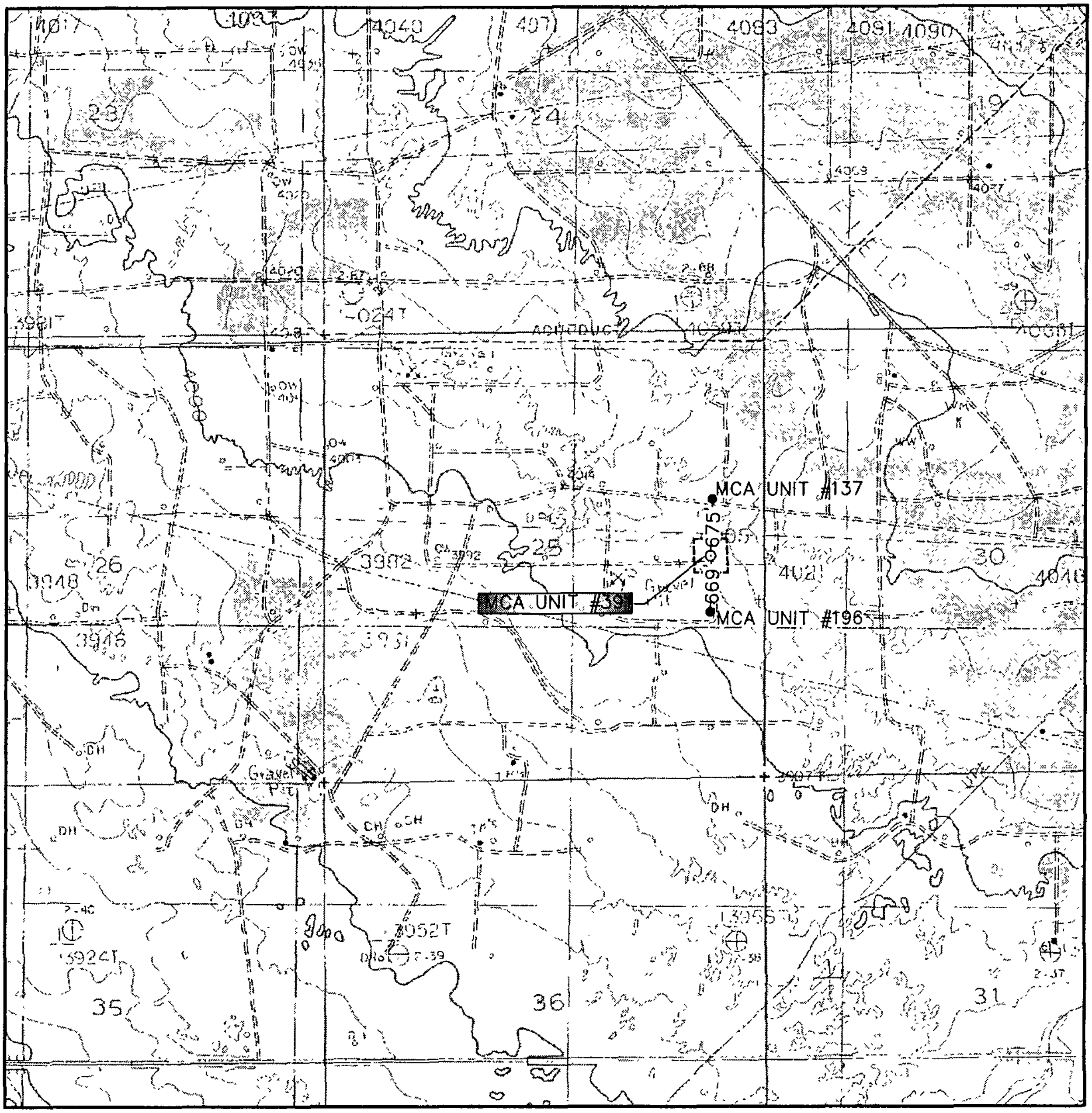
CONOCOPHILLIPS

MCA UNIT #391

Located 2622' FNL & 662' FEL, Section 25 Township 17 South, Range 32 East, N.M.P.M. Lea County, New Mexico

Drawn By: LVA	Date: July 5, 2007
Scale: 1"=100'	Field Book: 381 / 8-10, 19-22
Revision Date:	Quadrangle: Dog Lake
W.O. No: 2007-0639	Dwg. No.: L-2007-0639-A

LOCATION VERIFICATION MAP



SCALE: 1" = 2000'

CONTOUR INTERVAL:
DOG LAKE – 10'

SEC. 25 TWP. 17–S RGE. 32–E

SURVEY N.M.P.M.

COUNTY LEA

DESCRIPTION 2622' FNL & 662' FEL

ELEVATION 4013'

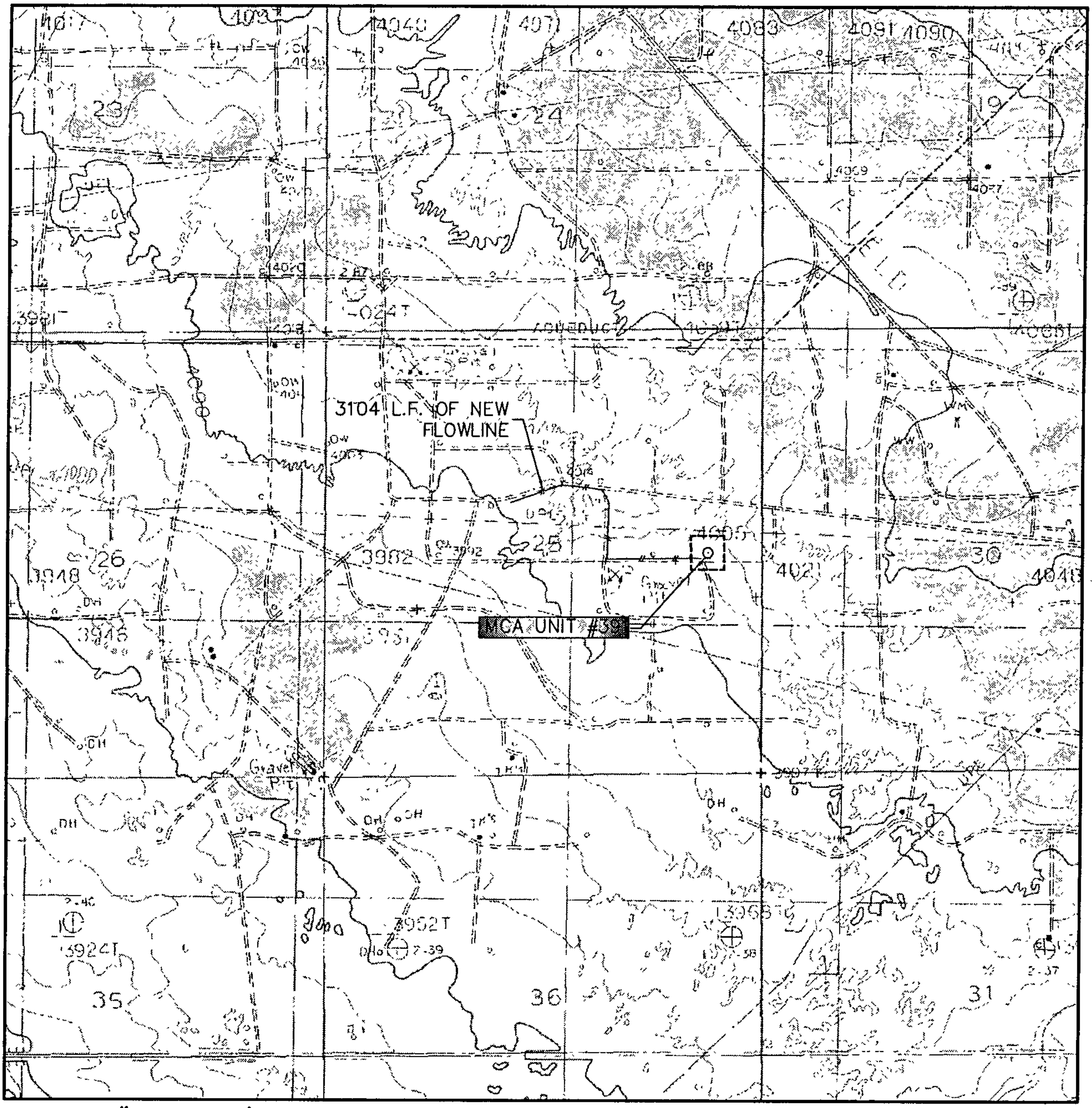
OPERATOR CONOCOPHILLIPS

LEASE MCA UNIT

U.S.G.S. TOPOGRAPHIC MAP
DOG LAKE

WEST COMPANY of Midland, Inc.
110 W. LOUISIANA, STE. 110
MIDLAND TEXAS, 79701
(432) 687–0865 – (432) 687–0868 FAX

LOCATION VERIFICATION MAP



SCALE: 1" = 2000'

CONTOUR INTERVAL:
DOG LAKE – 10'

SEC. 25 TWP. 17–S RGE. 32–E

SURVEY N.M.P.M.

COUNTY LEA

DESCRIPTION 2622' FNL & 662' FEL

ELEVATION 4013'

OPERATOR ConocoPhillips

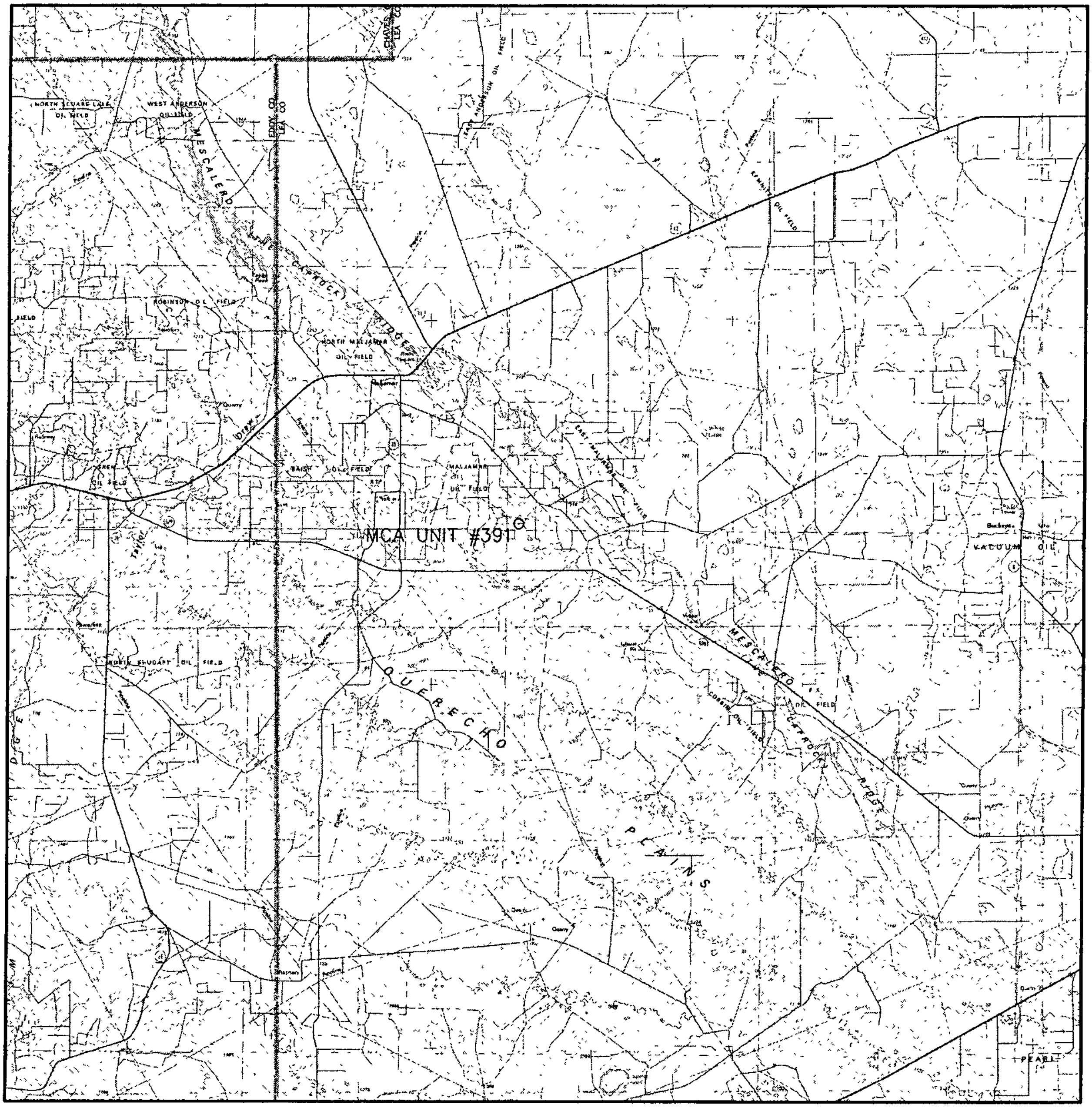
LEASE MCA UNIT

U.S.G.S. TOPOGRAPHIC MAP
DOG LAKE

NORTH

WEST COMPANY of Midland, Inc.
110 W. LOUISIANA, STE. 110
MIDLAND TEXAS, 79701
(432) 687–0865 – (432) 687–0868 FAX

VICINITY MAP



SCALE: 1" = 4 MILES

SEC. 25 TWP. 17-S RGE. 32-E

SURVEY N.M.P.M.

COUNTY LEA

DESCRIPTION 2622' FNL & 662' FEL

ELEVATION 4013'

OPERATOR CONOCOPHILLIPS

LEASE MCA UNIT

NORTH

WEST COMPANY of Midland, Inc.

110 W. LOUISIANA, STE. 110
MIDLAND TEXAS, 79701
(432) 687-0865 - (432) 687-0868 FAX

Master Drilling Plan
ConocoPhillips Company
MCA Unit
February 28, 2008

Lea County, NM
Pool: Maljamar; Grayburg-San Andres

MCA UNIT AREA

Lease	Sfx	Lessor	Twn	Rng	Sec	QQ
N/A		USA LC 061842	17	32	14	E2
N/A		Fee	17	32	14	W2
N/A		USA LC 059576	17	32	15	NE
088907	000	USA LC 054687	17	32	15	N2, SW, W2SE
269411	000	USA NM-080258	17	32	15	E2SE
N/A		State of New Mexico B-2366-16	17	32	16	NE, N2SE
N/A		State of New Mexico VO-3555	17	32	16	N2SW
109063	000	State of New Mexico B 155-5	17	32	16	S2SW
109063	000	State of New Mexico B 155-5	17	32	16	NW
088913	000	State of New Mexico B 2366-11	17	32	16	SWSE
088908	000	State of New Mexico B 4062-3	17	32	16	SESE
088912	000	USA LC 029405-B	17	32	17	W2
088912	000	USA LC 029405-B	17	32	17	W2E2
109069	000	USA NM LC 060329	17	32	17	E2E2
088912	000	USA LC 029405-B	17	32	18	E2
088912	000	USA LC 029405-B	17	32	18	E2W2
109069	000	USA NM LC 060329	17	32	18	NWNW
109069	000	USA NM LC 060329	17	32	18	SWSW
088911	000	USA LC 029405-A	17	32	19	N2
088912	000	USA LC 029405-B	17	32	19	S2
088911	000	USA LC 029405-A	17	32	20	N2
088912	000	USA LC 029405-B	17	32	20	S2
088909	000	USA LC 029509-A	17	32	21	N2, SW, N2SE
088910	000	USA LC 029509-B	17	32	21	S2SE
088909	000	USA LC 029509-A	17	32	22	W2NW
088910	000	USA LC 029509-B	17	32	22	NE
088910	000	USA LC 029509-B	17	32	22	E2NW
088910	000	USA LC 029509-B	17	32	22	NWSE
088910	000	USA LC 029509-B	17	32	22	SW
253943	000	USA LC 058395	17	32	22	E2SE
253943	000	USA LC 058395	17	32	22	SWSE
101798	000	USA LC 029400-A	17	32	23	NWSW
109067	000	USA LC 058697-A	17	32	23	S2SE
109066	000	USA LC 058698-A	17	32	23	N2SE
109066	000	USA LC 058698-A	17	32	23	NESW
109066	000	USA LC 058698-A	17	32	23	S2SW
109068	000	USA LC 058698-B	17	32	23	N2
N/A		USA LC 058697-B	17	32	25	All
262724	000	USA LC 058408-A	17	32	26	W2NE
262723	000	USA LC 058408-B	17	32	26	NESE, NWSE, S2SE
109066	000	USA LC 058698-A	17	32	26	S2NW
253944	000	USA LC 058699	17	32	26	SW
109062	000	USA LC 061841	17	32	26	N2NW
256034	000	USA NM 94188	17	32	26	E2NE
109065	000	USA LC 057210	17	32	27	NENE, SE, SWNE, W2

253947	000	USA LC 058396	17	32	27	NWNE, SENE
109065	000	USA LC 057210	17	32	28	All
256050	000	USA LC 029410-A	17	32	29	All
N/A		USA LC 029410-B	17	32	30	W2, SE, W2NE
253946	000	USA LC 060199-B	17	32	30	E2NE
N/A		USA LC 029410-B	17	32	31	E2SE, N2
N/A		USA LC 069105	17	32	31	E2SE
		USA NM 03428	17	32	31	SW
N/A		State of NM B-4109	17	32	32	NE, N2NW,
N/A		State of NM B-6768	17	32	32	SE, NESW
N/A		State of NM OG-5119	17	32	32	S2SW, NWSW, S2NW
109072	000	USA LC 029409-A	17	32	33	SW
109071	000	USA LC 059001-A	17	32	33	E2, N2NW, S2NW
109060	000	USA LC 058514	17	32	34	NE
109059	000	USA LC 058728	17	32	34	E2NW
109061	000	USA LC 059002	17	32	34	W2NW
N/A		USA LC 068140	17	32	34	SW
N/A		USA LC 060503	17	32	34	N2SE
N/A		USA NM 036852	17	32	34	S2SE
109068	000	USA LC 058698-B	17	32	35	W2
109068	000	USA LC 058407-B	17	32	35	NE
109068	000	USA LC 058409-B	17	32	35	SE
109070	000	USA LC 058697-B	17	33	30	W2

1. **Geologic Name of Surface Formation:**
   - Quaternary Alluvium and Dunes

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

   In the MCA Unit, the estimated tops of the geological markers and proposed Total Depth (TD) vary within a range of approximately 550 to 775'. The range of minimum to maximum depth for these markers and proposed TD range is presented in the table below. The datum for these depths is RKB or Rig Floor (which is 10' - 12' above Ground Level).

Formation Call	Top (MD)		Contents
	Minimum	Maximum	
Above top of Rustler			Fresh Water
Rustler	600	1170	
Salado	775	1380	
Grayburg	3270	3940	Oil, Gas, Salt Water and possible CO2 from old injection Program
Grayburg 6	3480	4170	Oil, Gas, Salt Water and possible CO2 from old injection Program
San Andres 7	3610	4345	Oil, Gas, Salt Water and possible CO2 from old injection Program
San Andres 9	3810	4585	Oil, Gas, Salt Water and possible CO2 from old injection Program
Proposed TD	4155	4705	Oil, Gas, Salt Water and possible CO2 from old injection Program

Note: For each individual well we will include with our Application for Permit to Drill (APD) our correlation pick depths for the formation tops and proposed TD for that individual well.

Protection of fresh water will be accomplished by setting the surface casing 25' - 70' into the Rustler Anhydrite formation 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.

3. 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	17-1/2"	0	40' – 87' (30' – 75' BGL)	13-3/8"	48#	H-40	STC	New	NA	NA	NA
Surf	12-1/4"	0	625'– 1240'	8-5/8"	24#	J-55	STC	New	5.49	2.5	8.2 / 9.42
Prod	7-7/8"	0	4155' – 4705'	5-1/2"	17#	J-55	LTC	New	2.17	2.01	3.09 / 3.64

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

Casing Design (Safety) Factors – BLM Criteria:

BLM Criteria for Minimum Design Factors

	Burst	Collapse	Tension
Casing Design Safety Factors	1.0	1.125	1.6 dry / 1.8 Buoyant

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 criteria for 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 criteria for 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 criteria for Minimum Acceptable Burst Design (Safety) Factor SFb = 1.0

Joint Strength Design (Safety) Factors – BLM Criteria

Surface Casing:

- SFj Dry = 244,000 lbs / (1240 ft x 24 lb/ft) = 244,000 lbs / 29,760 lbs = 8.20 Dry
- SFj Buoyant = 244,000 lbs / (1240 ft x 24 lb/ft) [1-(8.5/65.5)= 244,000 lbs / 25,898 lbs = 9.42 buoyant

Production Casing:

- SFj Dry = 247,000 lbs / (4705 ft x 17 lb/ft) = 247,000 lbs / 79,985 lbs = 3.09 Dry
- SFj Buoyant = 247,000 lbs / (4705 ft x 17 lb/ft) [1-(10.0/65.5)= 247,000 lbs / 67,773 lbs = 3.64 Buoyant

Collapse Design (Safety) Factors – BLM Criteria

Surface Casing:
SFc = 1370 psi / (8.5 ppg x .052 x 1240 ft) = 1370 psi / 548psi = 2.50
Production Casing:
SFc = 4910 psi / (10 ppg x .052 x 4705 ft) = 4910 psi / 2447 psi = 2.01

Burst Design (Safety) Factors – BLM Criteria

Surface Casing:
SFb = 2950 psi / (8.33 ppg x .052 x 1240 ft) = 2950 psi / 537 psi = 5.49
Production Casing:
SFb = 5320 psi / (7.15 ppg x .052 x 4705 ft) = 5320 psi / 1750 psi = 3.04 based on reservoir pressure data
SFb = 5320 psi / (10 ppg x .052 x 4705 ft) = 5320 psi / 2447 psi = 2.17 based on brine density used to drill to TD

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. 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 / {[(300 ft x .052 x 14.8 ppg) + (940 ft x .052 x 13.1 ppg)] – (1240 ft x .052 x 8.33 ppg)}
DF Collapse = 1370 psi / 334 psi
DF Collapse = 4.10

The maximum axial load on the Surface Casing would be the buoyant weight of the full string of casing plus an allowance for potential overpull in the amount of 30,000 lbs.

Surface Casing Axial (Tension) Design Factor
DF Tension = Joint Strength Rating / Buoyant Weight + Overpull Margin
Buoyancy Factor for fresh water (8.34 ppg fluid) = 1 – (8.34 / 65.5) = .873
Overpull Margin is selected to be 30,000 lbs
DF Tension = 244,000 lbs / [(1240 ft x 24 lb/ft x .873) + 30,0000 lbs]
DF Tension = 244,000 lbs / 55980 lbs
DF Tension = 4.36

Production Casing:

The maximum internal (burst) load would occur either during during fracture initiation or screen out. Fracture initiation occurs with 2% KCL water in the hole. Screen-out might occur with up to 12 ppg frac fluid in the hole.

For the fracture initiation load case, the design factor calculated at surface is:
DF Burst @ Surface for Fracture Initiation = Burst Rating / Maximum Applied Surface Pressure
DF Burst @ Surface for Fracture Initiation = 5320 psi / 4260 psi
DF Burst @ Surface for Fracture Initiation = 1.25

For the fracture initiation load case, the design factor calculated at TD is:
DF Burst @ TD for Fracture Initiation = Burst Rating / (Internal Pressure – Pore Pressure)
Internal Pressure at TD = Surface Pressure + Hydrostatic Pressure at TD of 2% KCL Water Column
Hydrostatic Pressure at TD of 2% KCL Water Column = 4705 ft x .052 x 8.6 ppg = 2104 psi
Surface Pressure at the time of Fracture Initiation = 4260 psi maximum
Internal Pressure at TD = 4260 psi + 2104 psi = 6364 psi
Pore Pressure in the Reservoir = 1750 psi approximately
DF Burst @ TD for Fracture Initiation = 5320 psi / (6364 psi - 1750 psi)
DF Burst @ TD for Fracture Initiation = 5320 psi / 4614 psi
DF Burst @ TD for Fracture Initiation = 1.15

For the screen out load case, the maximum burst loading occurs at TD and is calculated as follows:
DF Burst @ TD for Screen Out = Burst Rating / (Internal Pressure – Pore Pressure)
Internal Pressure at TD = Surface Pressure + Hydrostatic Pressure at TD of 12 ppg frac fluid
Hydrostatic Pressure at TD of 12 ppg frac fluid = 4705 ft x .052 x 12.0 ppg = 2936 psi
Maximum Allowable Surface Pressure at the time of Screen Out = 3450 psi maximum
Internal Pressure at TD at time of Screen Out = 3450 psi + 2936 psi = 6386 psi
Pore Pressure in the Reservoir = 1750 psi approximately
DF Burst @ TD for Fracture Initiation = 5320 psi / (6386 psi - 1750 psi)
DF Burst @ TD for Fracture Initiation = 5320 psi / 4636 psi
DF Burst @ TD for Fracture Initiation = 1.15

The maximum collapse load on the production casing occurs with the well pumped off on production. The maximum potential pore pressure in the well would be equal to or less 10 ppg which is the density of the brine drilling fluid used in drilling production hole interval from the Surface Casing Shoe to TD.

DF Collapse = Collapse Rating / Maximum Possible Pore Pressure
DF Collapse = 4910 / (10 ppg x .052 x 4705 ft) = 4910 psi / 2447 psi = 2.01

Production Casing Axial (Tension) Design Factor
DF Tension = Joint Strength Rating / Buoyant Weight + Overpull Margin
Buoyancy Factor for 10 ppg brine = 1 – (10.0 / 65.5) = .847
Overpull Margin is selected to be 30,000 lbs
DF Tension = 247,000 lbs / [(4705 ft x 17 lb/ft x .847) + 30,0000 lbs]
DF Tension = 247,000 lbs / 97,747 bs
DF Tension = 2.53

We propose options to our casing program as follows:

- **Single Stage Cementing:** We propose an option to perform a Single Stage cement job on the 5-1/2" production casing.

- **Two Stage Cementing:** We propose an option to run a Stage Tool in the 5-1/2" production casing and perform a two-stage cement job if losses are observed to occur while drilling the 7-7/8" production hole. The stage tool would be positioned near the top of the Grayburg formation. In any event in which we would propose to implement this contingency, a call would be made to the authorized officers at BLM and NMOCD to confirm permission prior to proceeding. **Also, if we do not circulate out any cement from the top of the Stage Tool, we must and will contact BLM and NMOCD to report this and obtain permission prior to proceeding with the 2nd Stage. A Cement Bond Log or other cement evaluation log will be run after moving off the drilling rig and prior to perforating to determine the top of cement on the Stage 1 cement job and this information will be communicated to BLM and NMOCD and permission will be obtained prior to continuing with the completion.**

- **Two Stage Cementing with External Casing Packers:** In the event that a waterflow is experienced while drilling the 7-7/8" production hole, we propose an option / contingency plan to run a Stage Tool with two each External Casing Packers (ECP's) in the 5-1/2" production casing and to perform a two stage cement job.

  The placement of the Stage Tool and External Casing Packers would be as follows:
  - The Lower External Casing Packer would be placed approximately 200 to 270' below the top of the Grayburg formation and would be above the shallowest planned perforation depth.
  - The Upper External Casing Packer would be placed approximately 500' to 1600' above the top of the Grayburg formation and would be above the waterflow.
  - The Stage Tool would be placed immediately above the Upper External Casing Packer.

  The execution of the Two Stage cement job with External Casing Packers would be as follows

  a. The Stage 1 cement would be pumped, placing cement from the casing shoe to the Stage Tool.

  b. The two ECP's would be simultaneously set by hydraulic pressure after bumping the Stage 1 cement Wiper Dart on the baffle on the float collar. The setting of the ECP's should shut off the water flow – isolating it between the ECP's.

  c. After setting the ECP's the Stage Tool would be opened by hydraulic pressure (or with the free fall opening cone if necessary) and the excess cement above the top of the Stage Tool would be circulated out. **Note: If we do not circulate out any cement from the top of the Stage Tool, we must and will contact BLM and NMOCD to report this and obtain permission prior to proceeding with the 2nd Stage. A Cement Bond Log or other cement evaluation log will be run after moving off the drilling rig and prior to perforating to determine the top of cement on the Stage 1 cement job and this information will be communicated to BLM and NMOCD and permission will be obtained prior to continuing with the completion.**

  d. The Stage 2 cement would be pumped placing cement from the Stage Tool to Surface. The closing wiper plug would be bumped on the stage tool and the Stage Tool would be closed with hydraulic pressure.

  In any event in which we would propose to implement this contingency, a call would be made to the authorized officers at BLM and NMOCD to confirm permission prior to proceeding.

Diagrams / schematics of the proposed casing program alternatives are attached.

4. Proposed cementing program:

For the cementing program a range is presented for the number of sacks of cement and for the bottom, top, and length of the lead slurries and tail slurries due to the variation in formation tops and planned TD for the planned / contemplated wells for which this Master Drilling Plan is intended.

13-3/8" Conductor:

Cement to surface with ready mix or Class C Neat cement. 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 300' above the casing shoe,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water

Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 85 deg F by UCA Method	
185 – 535 sx Class C + 6% bentonite + 2% CaCl2 + 0.125% Polyflake Excess = 170%	325 to 940	Surface	325 to 940	13.1	1.96	10.69	Time 12 hrs 18 hrs 24 hrs	Strength 316 psi 417 psi 506 psi

Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 91 deg F by UCA Method	
220 sx Class C + 2% CaCl2 + 0.125% Polyflake Excess = 100%	625' to 1240'	325' to 940'	300'	14.8	1.35	6.36	Time 3 hrs 9 hrs 12 hrs 24 hrs 48 hrs	Strength 50 psi 500 psi 793 psi 1266 psi 2183 psi

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 24 hrs after placement of the cement on the Surface Casing in order to achieve at least 500 psi compressive strength in both the Lead Slurry and Tail Slurry cements prior to drilling out of the Surface Casing.

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 the top of the Grayburg formation,
- Bring the Lead Slurry to surface.

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water.

Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
433 – 644 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125% Polyflake	3270' to 3940'	Surface	3270' to 3940'	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 = 88% - 135% (based on caliper if available)								

Tail Slurry (this is a CO_2 resistant cement)								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 115 deg F by UCA Method	
150 – 285 sx 65% Class C 35% POZ + 0.4% Dispersant	4155' to 4705'	3270' to 3940'	636' to 885'	16.4	0.98	3.76	Time 5 hrs 56 min 8 hrs 12 min 24 hrs 48 hrs 72 hrs	Strength 50 psi 500 psi 2806 psi 4690 psi 5661 psi
Excess = 26% - 83% (based on caliper if available)								

Displacement: 2% KCL water with approximately 250 ppm gluteraldehyde biocide.

5-1/2" Production Casing Cementing Program - Two-Stage Cementing Option (for Loss of Circulation Events):

We propose an option to use the two-stage cementing method for cementing the production casing if any loss of circulation events or heavy seepage is experienced while drilling the 7-7/8" hole. (see discussion in Item 3 above). The proposed two-stage cementing program would be as follows:

- Stage 1: Would place cement from the casing shoe to the stage tool.
- Stage 2: Would place cement from the stage tool to Surface.

Stage 1:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 1 – Lead Surry: None

Stage 1 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
150 – 285 sx 65% Class C 35% POZ + 0.4% Dispersant	4155' to 4705'	3270' to 3940'	636' to 885'	16.4	0.98	3.76	Time 5 hrs 56 min 8 hrs 12 min 24 hrs 48 hrs 72 hrs	Strength 50 psi 500 psi 2806 psi 4690 psi 5661 psi
Excess = 26% - 83% based on caliper if available								

Displacement: A volume of Fresh Water equal to the capacity volume from the stage tool to the float collar, followed by brine based mud.

Stage 2:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 2 – Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
382 – 592 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125% Polyflake	3000' to 3670'	Surface	3000' to 3670'	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 = 81% - 130% based on caliper if available								

Stage 2 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
100 sx Class C + 0.1% Retarder (if needed)	3270' to 3940'	3000' to 3670'	270'	14.8	1.33	6.359	Time 1 hrs 05 min 2 hrs 38 min 24 hrs 72 hrs	Strength 50 psi 500 psi 2800 psi 3182 psi
Excess = 184%								

Displacement: Fresh Water

5-1/2" Production Casing Cementing Program – Two-Stage Cementing Option with Stage Tool and External Casing Packers (for Water Flow Events):

We propose an option to use the two-stage cementing method with a Stage Tool and two each External Casing Packers if any waterflow event is experienced while drilling the 7-7/8" hole as discussed above in Item 3. The proposed two-stage cementing program would be as follows:

- Stage 1: Would place cement from the casing shoe to the stage tool
- Stage 2: Would place cement from the stage tool to Surface.

Stage 1:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 1 – Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
77 – 363 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125% Polyflake	3270' to 3940'	1670' to 3440'	500' to 1600'	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 = 126% - 234% based on caliper if available								

Stage 1 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
150 – 285 sx 65% Class C 35% POZ + 0.4% Dispersant	4155' to 4705'	3270' to 3940'	636' to 885'	16.4	0.98	3.76	Time 5 hrs 56 min 8 hrs 12 min 24 hrs 48 hrs 72 hrs	Strength 50 psi 500 psi 2806 psi 4690 psi 5661 psi
Excess = 26% - 83% based on caliper if available								

Displacement: A volume of Fresh Water equal to the capacity volume from the stage tool to the float collar, followed by brine based mud.

Stage 2:

Spacer: 20 bbls Fresh Water with an option to follow this with 1000 gallons SuperFlush 102 and 20 additional bbls Fresh Water

Stage 2 – Lead Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
145 – 584 sx 50% Class C 50% POZ + 10% bentonite + 8 lb/sx Salt + 0.2% Fluid Loss Additive + 0.125% Polyflake	1400' to 3170'	Surface	1400' to 3170'	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 = 42% - 162% based on caliper if available								

Stage 2 – Tail Slurry								
Volume (sx) & Recipe & Excess %	Bottom (ft MD)	Top (ft MD)	Length (ft)	Density (ppg)	Yield (cuft/sx)	Mix Wtr gal/sx	Compressive Strengths @ 113 deg F by Crush Method	
100 sx Class C + 0.1% Retarder (if needed)	1670' to 3440'	1400' to 3170'	270'	14.8	1.33	6.359	Time 1 hrs 05 min 2 hrs 38 min 24 hrs 72 hrs	Strength 50 psi 500 psi 2800 psi 3182 psi
Excess = 184%								

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 options presented above are estimates based on data from previous wells. We propose an option to adjust these volumes based on the caliper log data for this proposed well if available. Also, if no caliper log is available for this proposed well, we would propose an option to possibly increase the production casing cement volumes to account for any uncertainty in regard to the hole volume.

5. Pressure Control Equipment:

The blowout preventer equipment (BOP) will consist of 11", 2M equipment to conform to the requirements for a 2M System as described in Onshore Oil and Gas Order No. 2, III.A.2.a.ii. The blowout preventer equipment will be installed after running and cementing the surface casing and installing the wellhead and will be tested by a third party using a test plug. Ram type preventers and associated equipment will be tested to approved stack working pressure of 2000 psi. Annular type preventers, if used, will be tested to 50 percent of rated working pressure, and therefore will be tested to 1000 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.

6. Proposed Wellhead Program:

Casing Head: 8-5/8" Slip on and Weld x 11" 5M Casing Head installed on 8-5/8" surface casing
Tubing Head: 11" 5M x 7-1/6" 5M Tubing Head installed after setting 5-1/2" production casing

Or, alternatively:

Casing Head: 8-5/8" Slip on and Weld x 11" 3M Casing Head installed on 8-5/8" surface casing
Tubing Head: 11" 3M x 7-1/6" 5M Tubing Head installed after setting 5-1/2" production casing

7. Proposed Mud System:

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

DEPTH	TYPE and VOLUME	WEIGHT	VISCOSITY	WATERLOSS
0 – Surface Casing Point	Fresh Water Native Mud 320 bbls in lined earth pit	8.5 – 9.0 ppg	28 – 40 sec	N.C.
Surface Casing Point to TD	Brine 640 bbls in lined earth pit	10 ppg	29 sec	N.C.
Conversion to Mud at TD	Brine Based Mud 300 bbls in steel mud pits	10 ppg	34 – 45 sec	5 – 10 cc/30 min

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 brine and will be converted to a mud with starch, attapulgite, and lime upon reaching Total Depth (TD). The mud components will be:

- Brine (approximately 10 lb/gal density)
- Attapulgite
- Lime
- Starch
- Drilling Paper
- Other loss of circulation material if needed (nut plug, fiberous material, gilsonite, or asphalt)
- Soap Sticks if needed
- Diesel in sweeps if needed
- Lease crude oil as a spotting fluid if needed in the event of differential sticking

We do not plan to keep any weighting material at the wellsite.

The circulating system we plan to use while drilling would be a "U" shaped brine reserve pit. We plan to monitor the pit level visually, not with float type pit level monitoring system.

After reaching TD, if the well is not flowing from a waterflow, then we would bring circulation into the steel mud pits and circulate the hole and convert to a brine based mud circulating through the steel mud pits. In such event we would propose to monitor the pit level visually, not with a float type pit level monitoring system.

Gas detecting equipment 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.

8. **<u>Logging, Coring, and Testing Program:</u>**
   a. No drill stem tests will be done
   b. No mud logging is planned
   c. No whole cores are planned
   d. The open hole electrical logging program is planned to be as follows:
      - Total Depth to top of Grayburg or possibly to the surface casing shoe: Resistivity, Density, Spectral Gamma Ray and possibly BHC Sonic.
      - Total Depth to Surface Casing Shoe: Caliper
      - Total Depth to 200' MD, Gamma Ray and Neutron
      - Formation pressure data (XPT) on electric line if needed (optional)
      - Rotary Sidewall Cores on electric line if needed (optional)

9. Abnormal Pressures and Temperatures:

- It is possible that abnormal pressures may be encountered while drilling in the 7-7/8" hole interval from the surface casing shoe to TD. If encountered, it is expected that a water flow would occur with some gas, oil, and/or CO_2 associated with it. The source of any such abnormal pressure would be from CO_2 injection (from our previous CO_2 injection program) and water injection that got out of zone and charged up in natural fractures above the reservoir. On three of the six wells drilled by ConocoPhillips in MCA Unit in 2006, such waterflows with associated gas, oil, or CO_2 were encountered. In these wells, the waterflow was encountered in the upper Queen or Grayburg interval above the reservoir. However there have also been cases in the history of this field in which occurrences of water flow, or in some cases CO_2 flow, have occurred at shallower depths. But in all such cases that we are aware of, the flow has been somewhere below the surface casing shoe. We are not aware of any such flows occurring above the surface casing shoe. Other than these occasional charged up zones, no abnormal pressures are expected. We plan to shut in and bleed off our injectors in the area before drilling each well in order to relieve the injection pressure in reservoir in the area. Our experience is that this is very helpful in regard to reducing the pressure in the reservoir, but may not relieve all pressure from charged up zones above the reservoir.

  If a waterflow is encountered, our proposed plan is to let it flow while drilling to TD, and then run and cement the production casing using the two-stage method and employing a Stage Tool and two each External Casing Packers as described and discussed above. Our proposed plan in this regard is to shut off any such waterflow by the action of setting the External Casing Packers – containing any such waterflow zone between the two External Casing Packers.

  We will ensure that we have sufficient storage capacity at surface to provide for the possibility that the well may flow water. The estimated maximum rate of water flow (based on observations on past wells) is 120 bbl/hr flow rate.

- The expected maximum bottom hole pressure in the reservoir is approximately 1750 psi. However with our injectors operating we have some wells that exhibit higher pressure up to approximately 2750 psi in the reservoir. In this regard we judge that these wells have a highly permeable avenue of communication to the injectors thus causing them to exhibit this higher pressure in the reservoir. We anticipate that when we shut down and bleed off the injectors in the respective areas in preparation for the drilling program the pressure in the reservoir on these wells will be reduced to the normal reservoir pressure in the field which is approximately 1750 psi.

- Above the reservoir, it is possible that there may be charged up zones (charged up from water injection and/ or CO2 injection that got out of zone). Such charged up zones are not found on each well drilled in this field, but are found occasionally. We do not have any measurement of the pressure of such charged up zones – but we feel it is not practical to attempt to control such zones with hydrostatic mud weight. The typical practices in this field have been to let these zones flow while drilling to TD, and our observation is that these zones will typically deplete and stop flowing water after several days or can be isolated between external casing packers as is proposed in this Master Drilling Plan.

- The expected bottom hole temperature is 110 degrees F during logging or 115 degrees F bottom hole static temperature.

- The estimated H2S concentrations in the MCA Field is 11,000 – 14,000 ppm H2S with a gas rate of zero to 38 MCFPD. The 100 ppm H2S ROE is 0 - 59'. The 500 ppm ROE is 0 - 27'. ConocoPhillips will comply with the provisions of Oil and Gas Order # 6, Hydrogen Sulfide Operations and will provide H2S monitoring equipment which will be rigged up, tested, and operational prior to drilling out from surface casing. All persons arriving on location will have H2S certification & training that occurred within the last year. Each occurrence of H2S gas at surface is to be noted on the daily reports and any occurrence of H2S 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. Also, ConocoPhillips will provide an H2S Contingency Plan (please see copy attached) and will keep this plan updated and posted at the wellsite during drilling operations.

10. 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 the wells in our proposed program MCA Unit within two years after receiving approval of the APD.

Attachments:

- Attachment # 1 .... Proposed Casing and Cementing Program with Single Stage Cementing of Production Casing
- Attachment # 2 .... Proposed Casing and Cementing Program with Two-Stage Cementing of Production Casing
- Attachment # 3 .... Proposed Casing and Cementing Program with External Casing Packers and Two-Stage Cementing of Production Casing
- Attachment # 4 .... Diagram of Choke Manifold Equipment (Excerpted 54 FR 39528, Sept 27, 1989)
- Attachment # 5 .... BOP and Choke Manifold Schematic – 2M System (Figure 3-1, Appendix G, from BLM)
- Attachment # 6 .... BOP and Choke Manifold Schematic – 2M System (Figure 3-1A, Appendix G, from BLM)

Contact Information:

Program prepared by:
Steven O. Moore, Staff Drilling Engineer, ConocoPhillips Company
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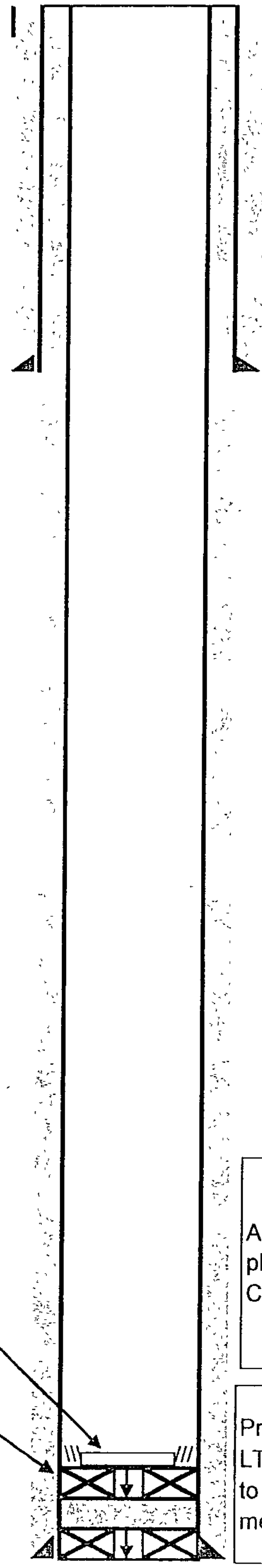
ConocoPhillips

Attachment # 1

MCA Unit
Proposed Casing & Cementing Program
with Single-Stage Cementing of Production Casing
(Alternative # 1)

Datum: RKB (10' -12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using Single-Stage Cementing for the production casing cement job if hole conditions are favorable (with no severe loss of circulation, heavy seepage, or waterflow events occurring during the drilling operations).



Conductor: 13-3/8" 48# H-40 ST&C set at 30' to 75' below ground level (40' to 87' MD RKB) and cemented to surface.

Surface Casing: 8-5/8" 24# J-55 ST&C set in the Rustler formation and cemented to surface.

A Single-Stage cement job is pumped placing cement from the Production Casing shoe to surface.

Cement Wiper Plug

Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# J-55 LT&C set 10' above TD and cemented to surface with single-stage cementing method.

Schematic prepared by:
Steven O. Moore, Staff Drilling Engineer
28-February-2008

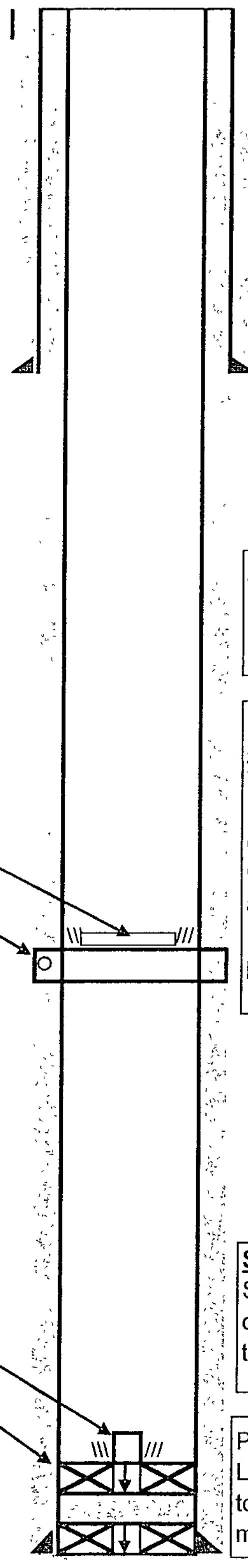
ConocoPhillips

Attachment # 2

MCA Unit
Proposed Casing & Cementing Program with Two-Stage Cementing of Production Casing (Alternative # 2)

Datum: RKB (10' - 12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using Two-Stage Cementing for the production casing cement job if loss of circulation occurrs during the drilling operations. See comments in "Step 1" to "Step 3" of this schematic.



Conductor: 13-3/8" 48# H-40 ST&C set at 30' to 75' below ground level (40' to 87' MD RKB) and cemented to surface.

Surface Casing: 8-5/8" 24# J-55 ST&C set in Rustler formation and cemented to surface.

Step 3:
Stage 2 Cement is pumped placing cement from the Stage Tool to surface.

Step 2:
The Stage Tool is opened by hydraulic pressure and the excess cement is circulated out from above the stage-tool. Circulation is continued for approximately 4 to 6 hrs until the Stage 1 cement has set and thus isolated the potential loss of circulation zone(s).

Stage 2 Wiper Plug / Closing Plug

Stage Tool at top of Grayburg

Step 1:
Stage 1 Cement is pumped placing cement from Production Casing shoe to the Stage Tool.

Stage 1 Wiper Dart

Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# J-55 LT&C set 10' above TD and cemented to surface with two-stage cementing method.

Schematic prepared by:
Steven O. Moore, Staff Drilling Engineer
28-February-2008

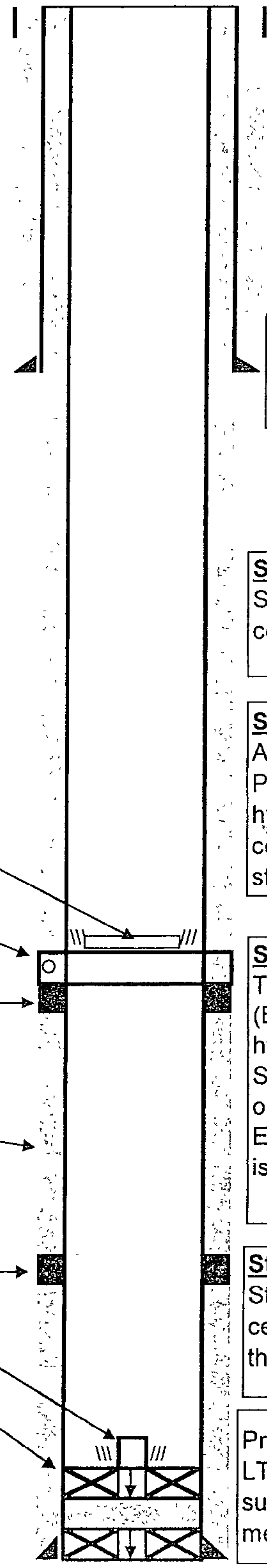
ConocoPhillips

Attachment # 3

MCA Unit
Proposed Casing & Cementing Program with ECP's and Two-Stage Cementing of Production Casing (Alternative # 3)

Datum: RKB (10' - 12' above ground level)

The intent of this alternative casing program is to provide a contingency plan for using External Casing Packers (ECP's) and Two-Stage Cementing to shut off a waterflow if such waterflow occurs while drilling the well. See comments in "Step 1" to "Step 4" of this schematic.



Conductor: 13-3/8" 48# H-40 ST&C set at 30' to 75' below ground level (40' to 87' MD RKB) and cemented to surface.

Surface Casing: 8-5/8" 24# J-55 ST&C set in Rustler formation and cemented to surface.

Step 4:
Stage 2 Cement is pumped placing cement from the Stage Tool to surface.

Step 3:
After setting the External Casing Packers, the Stage Tool is opened by hydraulic pressure and the excess cement is circulated out from above the stage-tool.

Stage 2 Wiper Plug / Closing Plug

Stage Tool
(immediately above the Upper External Casing Packer)

(Upper) External Casing Packer
(set above the waterflow)

Step 2:
The two External Casing Packers (ECP's) are simultaneously set by hydraulic pressure after bumping the Stage 1 Cement Wiper Dart on the baffle on the float collar. The setting of the ECP's should shut off the waterflow - isolating it between the two ECP's.

Possible waterflow between the bottom of the Salado and the top of the Grayburg 6 Formation

(Lower) External Casing Packer set 200 - 270' below the top of the Grayburg Formation and above the shallowest planned perforation.

Step 1:
Stage 1 Cement is pumped placing cement from Production Casing shoe to the Stage Tool.

Stage 1 Wiper Dart

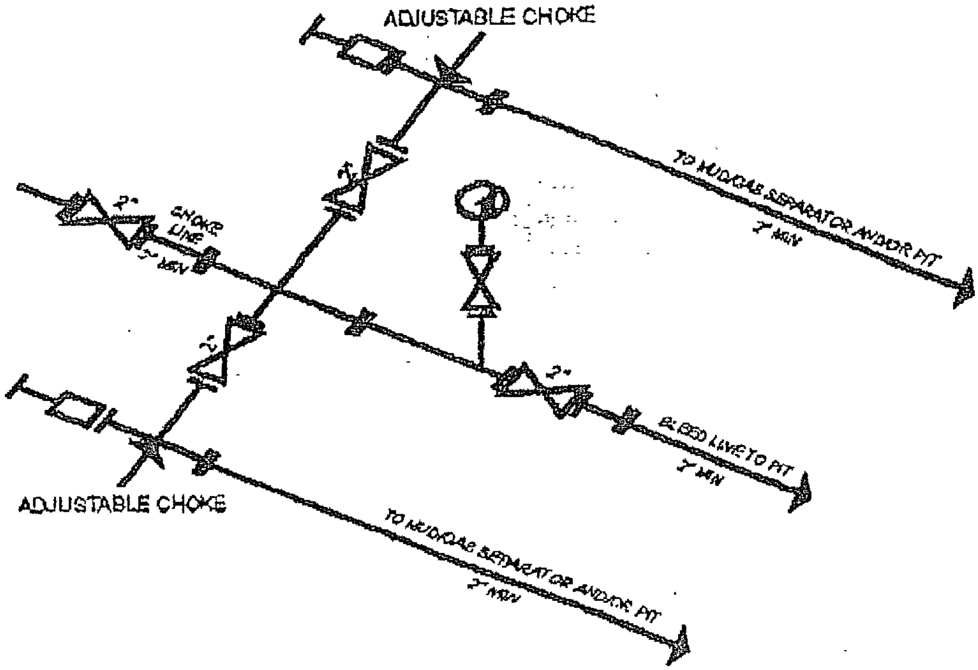
Float Shoe, one joint of casing, and Float Collar

Production casing: 5-1/2" 17# J-55 LT&C set 10' above TD and cemented to surface with two-stage cementing method

Schematic prepared by.
Steven O. Moore, Staff Drilling Engineer
28-February-2008

Attachment # 4

Attachment I. Diagrams of Choke Manifold Equipment



2M CHOKE MANIFOLD EQUIPMENT - CONFIGURATION OF CHOKES MAY VARY

Attachment # 5

2000 psi System

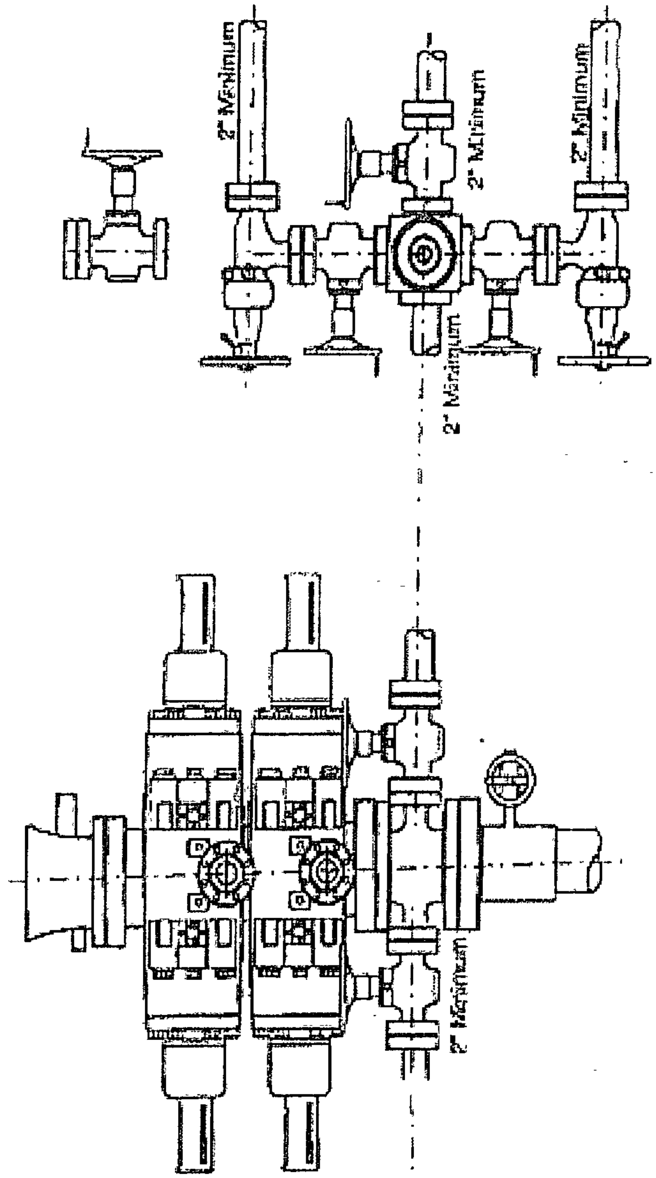


Figure 3-1

Appendix G

Attachment # 6

2000 psi System

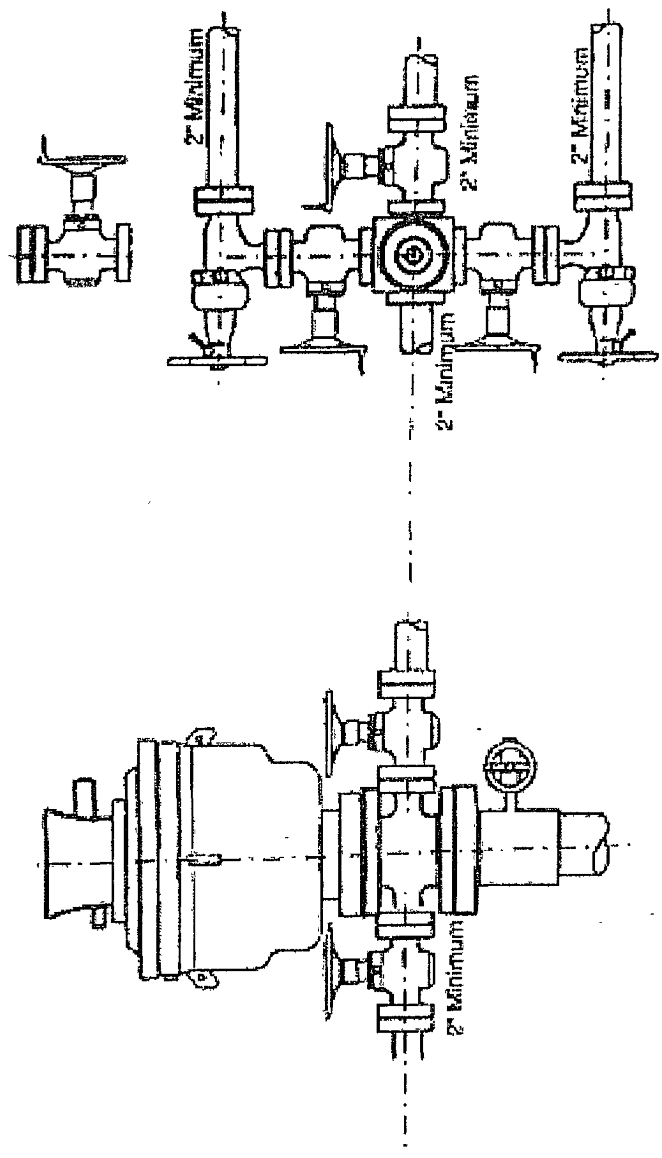


Figure 3-1A

Appendix G

PECOS DISTRICT
CONDITIONS OF APPROVAL

OPERATOR'S NAME:	ConocoPhillips Company
LEASE NO.:	LC-058697B
WELL NAME & NO.:	MCA Unit No. 391
SURFACE HOLE FOOTAGE:	2622' FNL & 662' FEL
BOTTOM HOLE FOOTAGE	Same
LOCATION:	Section 25, T. 17 S., R 32 E., NMPM
COUNTY:	Lea County, New Mexico

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Standard Conditions of Approval (COA) apply to this APD. If any deviations to these standards exist or special COAs are required, the section with the deviation or requirement will be checked below.

I. GENERAL PROVISIONS

The approval of the Application For Permit To Drill (APD) is in compliance with all applicable laws and regulations: 43 Code of Federal Regulations 3160, the lease terms, Onshore Oil and Gas Orders, Notices To Lessees, New Mexico Oil Conservation Division (NMOCD) Rules, National Historical Preservation Act As Amended, and instructions and orders of the Authorized Officer. Any request for a variance shall be submitted to the Authorized Officer on Form 3160-5, Sundry Notices and Report on Wells.

II. PERMIT EXPIRATION

If the permit terminates prior to drilling and drilling cannot be commenced within 60 days after expiration, an operator is required to submit Form 3160-5, Sundry Notices and Reports on Wells, requesting surface reclamation requirements for any surface disturbance. However, if the operator will be able to initiate drilling within 60 days after the expiration of the permit, the operator must have set the conductor pipe in order to allow for an extension of 60 days beyond the expiration date of the APD. (Filing of a Sundry Notice is required for this 60 day extension.)

III. ARCHAEOLOGICAL, PALEONTOLOGY & HISTORICAL SITES

Any cultural and/or paleontological resource discovered by the operator or by any person working on the operator's behalf shall immediately report such findings to the Authorized Officer. The operator is fully accountable for the actions of their contractors and subcontractors. The operator shall suspend all operations in the immediate area of such discovery until written authorization to proceed is issued by the Authorized Officer. An evaluation of the discovery shall be made by the Authorized Officer to determine the appropriate actions that shall be required to prevent the loss of significant cultural or scientific values of the discovery. The operator shall be held responsible for the cost of the proper mitigation measures that the Authorized Officer assesses after consultation with the operator on the evaluation and decisions of the discovery. Any unauthorized collection or disturbance of cultural or paleontological resources may result in a shutdown order by the Authorized Officer.

IV. NOXIOUS WEEDS

The operator shall be held responsible if noxious weeds become established within the areas of operations. Weed control shall be required on the disturbed land where noxious weeds exist, which includes the roads, pads, associated pipeline corridor, and adjacent land affected by the establishment of weeds due to this action. The operator shall consult with the Authorized Officer for acceptable weed control methods, which include following EPA and BLM requirements and policies.

V. SPECIAL REQUIREMENT(S)

Mitigation Measures: The mitigation measures include the special drilling stipulations, the standard stipulation for the Lesser Prairie Chicken Timing Stipulations, the standard stipulation for surface flowlines, the standard stipulation for overhead electrical lines, and the standard stipulations for permanent resource roads.

Timing Limitation Stipulation/Condition of Approval for Lesser Prairie-Chicken: Oil and gas activities including 3-D geophysical exploration, and drilling will not be allowed in lesser prairie-chicken habitat during the period from March 15 through June 15 annually. During that period, other activities that produce noise or involve human activity, such as the maintenance of oil and gas facilities, geophysical exploration other than 3-D operations, and pipeline, road, and well pad construction, will be allowed except between 3:00 am and 9:00 am. The 3:00 am to 9:00 am restriction will not apply to normal, around-the-clock operations, such as venting, flaring, or pumping, which do not require a human presence during this period. Additionally, no new drilling will be allowed within up to 200 meters of leks known at the time of permitting. Normal vehicle use on existing roads will not be restricted. Exhaust noise from pump jack engines must be muffled or otherwise controlled so as not to exceed 75 db measured at 30 ft. from the source of the noise.

MCA Unit # 391: Pit East V-Door South

VI. CONSTRUCTION

A. NOTIFICATION

The BLM shall administer compliance and monitor construction of the access road and well pad. Notify the Carlsbad Field Office at (505) 234-5972 at least 3 working days prior to commencing construction of the access road and/or well pad.

When construction operations are being conducted on this well, the operator shall have the approved APD and Conditions of Approval (COA) on the well site and they shall be made available upon request by the Authorized Officer.

B. TOPSOIL

The operator shall stockpile the topsoil of the well pad. The topsoil shall not be used to backfill the reserve pit and will be used for interim and final reclamation.

C. RESERVE PITS

The reserve pit shall be constructed and closed in accordance with the NMOCD rules.

The reserve pit shall be constructed 120' X 130' on the East side of the well pad V-Door South.

The reserve pit shall be constructed, so that upon completion of drilling operations, the dried pit contents shall be buried a minimum depth of three feet below ground level. Should the pit content level not meet the three foot minimum depth requirement, the excess contents shall be removed until the required minimum depth of three feet below ground level has been met. The operator shall properly dispose of the excess contents at an authorized disposal site.

The reserve pit shall be constructed and maintained so that runoff water from outside the location is not allowed to enter the pit. The berms surrounding the entire perimeter of the pit shall extend a minimum of two (2) feet above ground level. At no time will standing fluids in the pit be allowed to rise above ground level.

The reserve pit shall be fenced on three (3) sides during drilling operations. The fourth side shall be fenced immediately upon rig release.

D. FEDERAL MINERAL MATERIALS PIT

If the operator elects to surface the access road and/or well pad, mineral materials extracted during construction of the reserve pit may be used for surfacing the well pad and access road and other facilities on the lease.

Payment shall be made to the BLM prior to removal of any additional federal mineral materials from any site other than the reserve pit. Call the Carlsbad Field Office at (505) 234-5972.

E. WELL PAD SURFACING

Surfacing of the well pad is not required.

If the operator elects to surface the well pad, the surfacing material may be required to be removed at the time of reclamation.

The well pad shall be constructed in a manner which creates the smallest possible surface disturbance, consistent with safety and operational needs.

F. ON LEASE ACCESS ROADS

Road Width
The access road shall have a driving surface that creates the smallest possible surface disturbance and does not exceed fourteen (14) feet in width. The maximum width of surface disturbance, when constructing the access road, shall not exceed thirty (30) feet.

Surfacing
Surfacing material is not required on the new access road driving surface. If the operator elects to surface the new access road or pad, the surfacing material may be required to be removed at the time of reclamation.

Where possible, no improvements should be made on the unsurfaced access road other than to remove vegetation as necessary, road irregularities, safety issues, or to fill low areas that may sustain standing water.

The Authorized Officer reserves the right to require surfacing of any portion of the access road at any time deemed necessary. Surfacing may be required in the event the road deteriorates, erodes, road traffic increases, or it is determined to be beneficial for future field development. The surfacing depth and type of material will be determined at the time of notification.

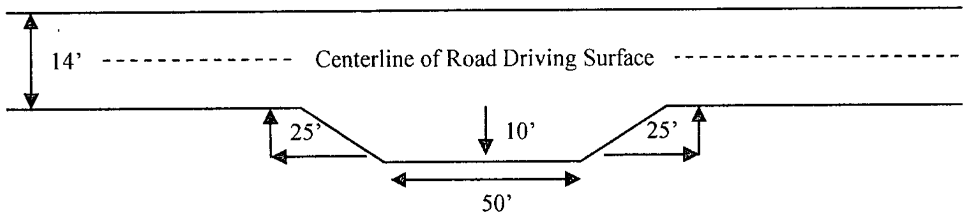
Crowning
Crowning shall be done on the access road driving surface. The road crown shall have a grade of approximately 2% (i.e., a 1" crown on a 14' wide road). The road shall conform to Figure 1; cross section and plans for typical road construction.

Ditching

Ditching shall be required on both sides of the road.

Turnouts
Vehicle turnouts shall be constructed on the road. Turnouts shall be intervisible with interval spacing distance less than 1000 feet. Turnouts shall be constructed on all blind curves. Turnouts shall conform to the following diagram:

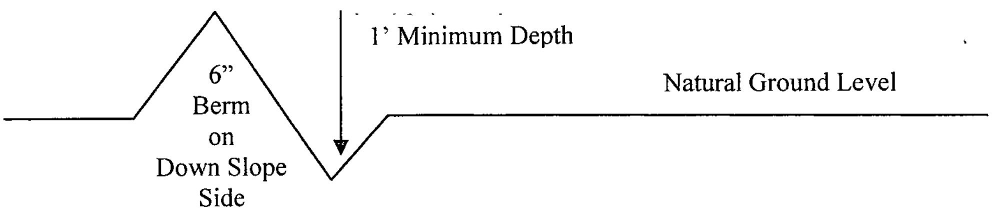
Standard Turnout – Plan View



Drainage
Drainage control systems shall be constructed on the entire length of road (e.g. ditches, sidehill outsloping and insloping, lead-off ditches, culvert installation, and low water crossings).

A typical lead-off ditch has a minimum depth of 1 foot below and a berm of 6 inches above natural ground level. The berm shall be on the down-slope side of the lead-off ditch.

Cross Section of a Typical Lead-off Ditch



All lead-off ditches shall be graded to drain water with a 1 percent minimum to 3 percent maximum ditch slope. The spacing interval are variable for lead-off ditches and shall be determined according to the formula for spacing intervals of lead-off ditches, but may be amended depending upon existing soil types and centerline road slope (in %);

Formula for Spacing Interval of Lead-off Ditches

Example - On a 4% road slope that is 400 feet long, the water flow shall drain water into a lead-off ditch. Spacing interval shall be determined by the following formula:

$$\text{400 foot road with 4\% road slope: } \frac{400'}{4\%} + 100' = 200' \text{ lead-off ditch interval}$$

Culvert Installations

Appropriately sized culvert(s) shall be installed at the deep waterway channel flow crossing.

Cattleguards

An appropriately sized cattleguard(s) sufficient to carry out the project shall be installed and maintained at fence crossing(s).

Any existing cattleguard(s) on the access road shall be repaired or replaced if they are damaged or have deteriorated beyond practical use. The operator shall be responsible for the condition of the existing cattleguard(s) that are in place and are utilized during lease operations.

A gate shall be constructed and fastened securely to H-braces.

Fence Requirement

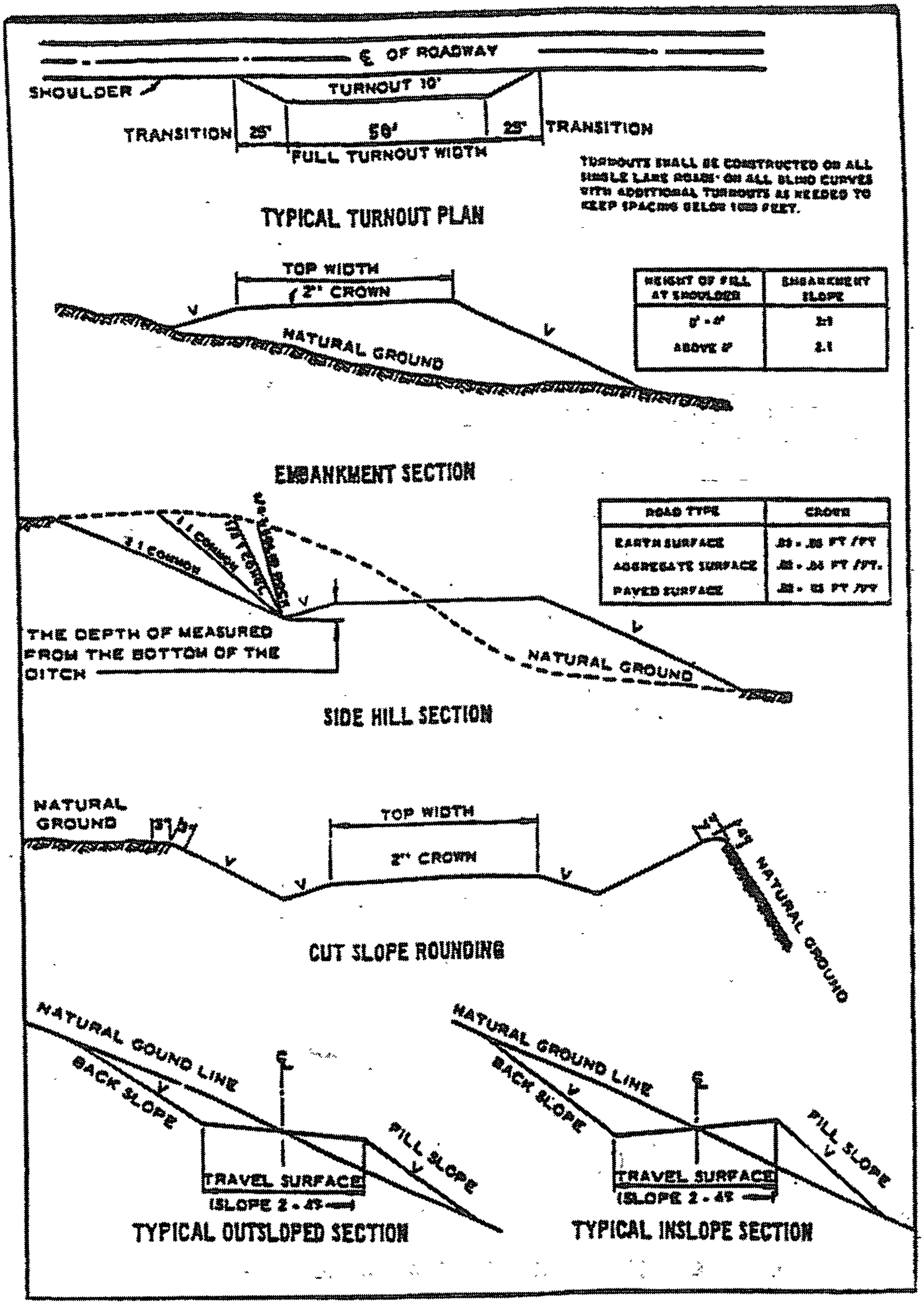
Where entry is required across a fence line, the fence shall be braced and tied off on both sides of the passageway prior to cutting.

The operator shall notify the private surface landowner or the grazing allotment holder prior to crossing any fence(s).

Public Access

Public access on this road shall not be restricted by the operator without specific written approval granted by the Authorized Officer.

Figure 1 – Cross Sections and Plans For Typical Road Sections



VII. DRILLING

A. DRILLING OPERATIONS REQUIREMENTS

The BLM is to be notified a minimum of **4 hours** in advance for a representative to witness:

a. Spudding well
b. Setting and/or Cementing of all casing strings
c. BOP/BOPE tests

☒ **Lea County**
Call the Hobbs Field Station, 414 West Taylor, Hobbs NM 88240, (575) 393-3612

1. A Hydrogen Sulfide (H2S) Drilling Plan should be activated 500 feet prior to drilling into the **Grayburg/San Andres** formation.

2. Unless the production casing has been run and cemented or the well has been properly plugged, the drilling rig shall not be removed from over the hole without prior approval.

B. CASING

Note: All casing shall meet or exceed API standards for new casing. Onshore Order 2.III.B.1.a (Any casing substitutions must have prior approval)

Centralizers required on surface casing as per Onshore Order 2.III.B.1.f

Possible lost circulation in the Grayburg and San Andres Formation.
Possible water and brine flows in the Salado and Artesia Groups.

1. The **8-5/8 inch** surface casing shall be set a minimum of **25 feet into the Rustler Anhydrite and above top of the salt** and cemented to the surface. **If salt is penetrated surface casing shall be set 25 feet above the salt.**

   a. If cement does not circulate to the surface, the appropriate BLM office shall be notified and a temperature survey utilizing an electronic type temperature survey with surface log readout will be used or a cement bond log shall be run to verify the top of the cement.

   b. Wait on cement (WOC) time for a primary cement job will be a minimum 18 hours for a water basin, 24 hours in the potash area, or 500 pounds compressive strength, whichever is greater. (This is to include the lead cement).

c. **Provide compressive strengths including hours to reach required 500 pounds compressive strength prior to cementing each casing string.**

d. Wait on cement (WOC) time for a remedial job will be a minimum of 4 hours after bringing cement to surface or 500 pounds compressive strength, whichever is greater.

e. If cement falls back, remedial action will be done prior to drilling out that string.

2. The minimum required fill of cement behind the **5-1/2 inch** production casing is:

a. **If No DV tool is ran cement shall:**

☒ Cement to surface. If cement does not circulate see B.1.a-e above.

b. **If DV too is ran the First stage to DV tool, cement shall:**

☒ Cement to circulate. If cement does not circulate, contact the appropriate BLM office, before proceeding with second stage cement job.

c. **Second stage above DV tool, cement shall:**

☒ Cement to surface. If cement does not circulate see B.1.a-e above.

3. If hardband drill pipe is rotated inside casing, returns will be monitored for metal. If metal is found in samples, drill pipe will be pulled and rubber protectors which have a larger diameter than the tool joints of the drill pipe will be installed prior to continuing drilling operations.

C. PRESSURE CONTROL

1. All blowout preventer (BOP) and related equipment (BOPE) shall comply with well control requirements as described in Onshore Oil and Gas Order No. 2 and API RP 53 Sec. 17.

2. The appropriate BLM office shall be notified a minimum of **4 hours** in advance for a representative to witness the tests.

a. The tests shall be done by an independent service company.

b. The results of the test shall be reported to the appropriate BLM office.

c. 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.

d. 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.

See Master Drilling Plan for details on Drilling activities

LB 3/27/08

VIII. PRODUCTION (POST DRILLING)

A. WELL STRUCTURES & FACILITIES

Placement of Production Facilities
Production facilities should be placed on the well pad to allow for maximum interim recontouring and revegetation of the well location.

Containment Structures
The containment structure shall be constructed to hold the capacity of the entire contents of the largest tank, plus 24 hour production, unless more stringent protective requirements are deemed necessary by the Authorized Officer.

Painting Requirement
All above-ground structures including meter housing that are not subject to safety requirements shall be painted a flat non-reflective paint color
Shale Green, Munsell Soil Color Chart # 5Y 4/2

B. PIPELINES

STANDARD STIPULATIONS FOR SURFACE INSTALLED PIPELINES

A copy of the APD and attachments, including stipulations, survey plat and/or map, will be on location during construction. BLM personnel may request to you a copy of your permit during construction to ensure compliance with all stipulations.

Holder agrees to comply with the following stipulations to the satisfaction of the Authorized Officer:

1. The holder shall indemnify the United States against any liability for damage to life or property arising from the occupancy or use of public lands under this grant.

2. The holder shall comply with all applicable Federal laws and regulations existing or hereafter enacted or promulgated. In any event, the holder shall comply with the Toxic Substances Control Act of 1976 as amended, 15 USC 2601 et seq. (1982) with regards to any toxic substances that are used, generated by or stored on the right-of-way or on facilities authorized under this right-of-way grant. (See 40 CFR, Part 702-799 and especially, provisions on polychlorinated biphenyls, 40 CFR 761.1-761.193.) Additionally, any release of toxic substances (leaks, spills, etc.) in excess of the reportable quantity established by 40 CFR, Part 117 shall be reported as required by the Comprehensive Environmental Response, Compensation, and Liability Act, section 102b. A copy of any report required or requested by any Federal agency or State government as a result of a reportable release or spill of any toxic substances shall be furnished to the authorized officer concurrent with the filing of the reports to the involved Federal agency or State government.

3. The holder agrees to indemnify the United States against any liability arising from the

release of any hazardous substance or hazardous waste (as these terms are defined in the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. 9601, et seq. or the Resource Conservation and Recovery Act, 42 U.S.C. 6901, et seq.) on the Right-of-Way (unless the release or threatened release is wholly unrelated to activity of the Right-of-Way holder's activity on the Right-of-Way), or resulting from the activity of the Right-of-Way holder on the Right-of-Way. This agreement applies without regard to whether a release is caused by the holder, its agent, or unrelated third parties.

4. The holder shall be liable for damage or injury to the United States to the extent provided by 43 CFR Sec. 2883.1-4. The holder shall be held to a standard of strict liability for damage or injury to the United States resulting from pipe rupture, fire, or spills caused or substantially aggravated by any of the following within the right-of-way or permit area:

a. Activities of the holder including, but not limited to construction, operation, maintenance, and termination of the facility.

b. Activities of other parties including, but not limited to:

(1) Land clearing.
(2) Earth-disturbing and earth-moving work.
(3) Blasting.
(4) Vandalism and sabotage.

c. Acts of God.

The maximum limitation for such strict liability damages shall not exceed one million dollars ($1,000,000) for any one event, and any liability in excess of such amount shall be determined by the ordinary rules of negligence of the jurisdiction in which the damage or injury occurred.

This section shall not impose strict liability for damage or injury resulting primarily from an act of war or from the negligent acts or omissions of the United States.

5. If, during any phase of the construction, operation, maintenance, or termination of the pipeline, any oil, salt water, or other pollutant should be discharged from the pipeline system, impacting Federal lands, the control and total removal, disposal, and cleaning up of such oil, salt water, or other pollutant, wherever found, shall be the responsibility of the holder, regardless of fault. Upon failure of the holder to control, dispose of, or clean up such discharge on or affecting Federal lands, or to repair all damages resulting therefrom, on the Federal lands, the Authorized Officer may take such measures as he deems necessary to control and clean up the discharge and restore the area, including, where appropriate, the aquatic environment and fish and wildlife habitats, at the full expense of the holder. Such action by the Authorized Officer shall not relieve the holder of any responsibility as provided herein.

6. All construction and maintenance activity will be confined to the authorized right-of-way width of ___25___ feet.

7. No blading or clearing of any vegetation will be allowed unless approved in writing by the Authorized Officer.

8. The holder shall install the pipeline on the surface in such a manner that will minimize suspension of the pipeline across low areas in the terrain. In hummocky of duney areas, the pipeline will be "snaked" around hummocks and dunes rather then suspended across these features.

9. The pipeline shall be buried with a minimum of **24** inches under all roads, "two-tracks," and trails. Burial of the pipe will continue for 20 feet on each side of each crossing. The condition of the road, upon completion of construction, shall be returned to at least its former state with no bumps or dips remaining in the road surface.

10. The holder shall minimize disturbance to existing fences and other improvements on public lands. The holder is required to promptly repair improvements to at least their former state. Functional use of these improvements will be maintained at all times. The holder will contact the owner of any improvements prior to disturbing them. When necessary to pass through a fence line, the fence shall be braced on both sides of the passageway prior to cutting of the fence. No permanent gates will be allowed unless approved by the Authorized Officer.

11. In those areas where erosion control structures are required to stabilize soil conditions, the holder will install such structures as are suitable for the specific soil conditions being encountered and which are in accordance with sound resource management practices.

12. Excluding the pipe, all above-ground structures not subject to safety requirement shall be painted by the holder to blend with the natural color of the landscape. The paint used shall be a color which simulates "Standard Environmental Colors" – **Shale Green**, Munsell Soil Color No. 5Y 4/2; designated by the Rocky Mountain Five State Interagency Committee.

13. The pipeline will be identified by signs at the point of origin and completion of the right-of-way and at all road crossings. At a minimum, signs will state the holder's name, BLM serial number, and the product being transported. Signs will be maintained in a legible condition for the life of the pipeline.

14. The holder shall not use the pipeline route as a road for purposes other than routine maintenance as determined necessary by the Authorized Officer in consultation with the holder. The holder will take whatever steps are necessary to ensure that the pipeline route is not used as a roadway.

15. Any cultural and/or paleontological resource (historic or prehistoric site or object) discovered by the holder, or any person working on his hehalf, on public or Federal land shall be immediately reported to the authorized officer. Holder shall suspend all operations in the immediate area of such discovery until written authorization to proceed is issued by the authorized officer. An evaluation of the discovery will be made by the authorized officer to determine appropriate cultural or scientific values. The holder will be responsible for the cost of evaluation and any decision as to proper mitigation measures will be made by the authorized officer after consulting with the holder.

(March 1989)

C. ELECTRIC LINES

STANDARD STIPULATIONS FOR OVERHEAD ELECTRIC DISTRIBUTION LINES

A copy of the APD and attachments, including stipulations, survey plat and/or map, will be on location during construction. BLM personnel may request to you a copy of your permit during construction to ensure compliance with all stipulations.

Holder agrees to comply with the following stipulations to the satisfaction of the Authorized Officer:

1. The holder shall indemnify the United States against any liability for damage to life or property arising from the occupancy or use of public lands under this grant.

2. The holder shall comply with all applicable Federal laws and regulations existing or hereafter enacted or promulgated. In any event, the holder shall comply with the Toxic Substances Control Act of 1976 as amended, 15 USC 2601 et seq. (1982) with regards to any toxic substances that are used, generated by or stored on the right-of-way or on facilities authorized under this right-of-way grant. (See 40 CFR, Part 702-799 and especially, provisions on polychlorinated biphenyls, 40 CFR 761.1-761.193.) Additionally, any release of toxic substances (leaks, spills, etc.) in excess of the reportable quantity established by 40 CFR, Part 117 shall be reported as required by the Comprehensive Environmental Response, Compensation, and Liability Act, section 102b. A copy of any report required or requested by any Federal agency or State government as a result of a reportable release or spill of any toxic substances shall be furnished to the authorized officer concurrent with the filing of the reports to the involved Federal agency or State government.

3. The holder agrees to indemnify the United States against any liability arising from the release of any hazardous substance or hazardous waste (as these terms are defined in the Comprehensive Environmental Response, Compensation and Liability Act of 1980, 42 U.S.C. 9601, et seq. or the Resource Conservation and Recovery Act, 42 U.S.C. 6901, et seq.) on the Right-of-Way (unless the release or threatened release is wholly unrelated to the Right-of-Way holder's activity on the Right-of-Way), or resulting from the activity of the Right-of-Way holder on the Right-of-Way.

This agreement applies without regard to whether a release is caused by the holder, its agent, or unrelated third parties.

4. There will be no clearing or blading of the right-of-way unless otherwise agreed to in writing by the Authorized Officer.

5. Powerlines shall be constructed in accordance to standards outlined in "Suggested Practices for Raptor Protection on Powerlines, " Raptor Research Foundation, Inc., 1981. The holder shall assume the burden and expense of proving that pole designs not shown in the above publication are "raptor safe." Such proof shall be provided by a raptor expert approved by the Authorized Officer. The BLM reserves the right to require modification or additions to all powerline structures placed on this right-of-way, should they be necessary to ensure the safety of large perching birds. Such modifications and/or additions shall be made by the holder without liability or expense to the United States.

6. The holder shall minimize disturbance to existing fences and other improvements on public lands. The holder is required to promptly repair improvements to at least their former state. Functional use of these improvements will be maintained at all times. The holder will contact the owner of any improvements prior to disturbing them. When necessary to pass through a fence line, the fence shall be braced on both sides of the passageway prior to cutting the fence. No permanent gates will be allowed unless approved by the Authorized Officer.

7. The BLM serial number assigned to this authorization shall be posted in a permanent, conspicuous manner where the power line crosses roads and at all serviced facilities. Numbers will be at least two inches high and will be affixed to the pole nearest the road crossing and at the facilities served.

8. Upon cancellation, relinquishment, or expiration of this grant, the holder shall comply with those abandonment procedures as prescribed by the Authorized Officer.

9. All surface structures (poles, lines, transformers, etc.) shall be removed within 180 days of abandonment, relinquishment, or termination of use of the serviced facility or facilities or within 180 days of abandonment, relinquishment, cancellation, or expiration of this grant, whichever comes first. This will not apply where the power line extends service to an active, adjoining facility or facilities.

10. Any cultural and/or paleontological resource (historic or prehistoric site or object) discovered by the holder, or any person working on his behalf, on public or Federal land shall be immediately reported to the Authorized Officer. Holder shall suspend all operations in the immediate area of such discovery until written authorization to proceed is issued by the Authorized Officer. An evaluation of the discovery will be made by the Authorized Officer to determine appropriate actions to prevent the loss of significant cultural or scientific values. The holder will be responsible for the cost of evaluation and any decision as to proper mitigation measures will be made by the Authorized Officer after consulting with the holder.

11. Special Stipulations:
   - For reclamation remove poles, lines, transformer, etc. and dispose of properly.
   - Fill in any holes from the poles removed.
   - See attached reclamation plans.

IX. INTERIM RECLAMATION & RESERVE PIT CLOSURE

A. INTERIM RECLAMATION

If the well is a producer, interim reclamation shall be conducted on the well site in accordance with the orders of the Authorized Officer. The operator shall submit a Sundry Notices and Reports on Wells (Notice of Intent), Form 3160-5, prior to conducting interim reclamation.

During the life of the development, all disturbed areas not needed for active support of production operations should undergo interim reclamation in order to minimize the environmental impacts of development on other resources and uses.

At the time reserve pits are to be reclaimed, operators should work with BLM surface management specialists to devise the best strategies to reduce the size of the location. Any reductions should allow for remedial well operations, as well as safe and efficient removal of oil and gas.

During reclamation, the removal of caliche is important to increasing the success of revegetating the site. Removed caliche may be used for road repairs, fire walls or for building other roads and locations. In order to operate the well or complete workover operations, it may be necessary to drive, park and operate on restored interim vegetation within the previously disturbed area. Disturbing revegetated areas for production or workover operations will be allowed. If there is significant disturbance and loss of vegetation, the area will need to be revegetated. Communicate with the appropriate BLM office for any exceptions/exemptions if needed.

B. RESERVE PIT CLOSURE

The reserve pit, when dried and closed, shall be recontoured, all trash removed, and reseeded as follows:

Seed Mixture 2, for Sandy Sites

The holder shall seed all disturbed areas with the seed mixture listed below. The seed mixture shall be planted in the amounts specified in pounds of pure live seed (PLS)* per acre. There shall be no primary or secondary noxious weeds in the seed mixture. Seed will be tested and the viability testing of seed will be done in accordance with State law (s) and within nine (9) months prior to purchase. Commercial seed will be either certified or registered seed. The seed container will be tagged in accordance with State law(s) and available for inspection by the authorized officer.

Seed will be planted using a drill equipped with a depth regulator to ensure proper depth of planting where drilling is possible. The see mixture will be evenly and uniformly planted over the disturbed area (smaller/heavier seeds have a tendency to drop the bottom of the drill and are planted first). The holder shall take appropriate measures to ensure this does not occur. Where drilling is not possible, seed will be broadcast and the area shall be raked or chained to cover the seed. When broadcasting the seed, the pounds per acre are to be doubled. The seeding will be repeated until a satisfactory stand is established as determined by the authorized officer. Evaluation of growth will not be made before completion of at least one full growing season after seeding.

Species to be planted in pounds of pure live seed* per acre:

Species	lb/acre
Sand dropseed (Sporobolus cryptandrus)	1.0
Sand love grass (Eragrostis trichodes)	1.0
Plains bristlegrass (Setaria macrostachya)	2.0

*Pounds of pure live seed:

Pounds of seed **x** percent purity **x** percent germination = pounds pure live seed

(Insert Seed Mixture Here)

X. FINAL ABANDONMENT & REHABILITATION REQUIREMENTS

Upon abandonment of the well and/or when the access road is no longer in service the Authorized Officer shall issue instructions and/or orders for surface reclamation and restoration of all disturbed areas.

On private surface/federal mineral estate land the reclamation procedures on the road and well pad shall be accomplished in accordance with the private surface land owner agreement.