

# DRILLING PROGNOSIS

WELL: DOE CANYON 12 (DC-12)

FIELD: Doe Canyon

LOCATION: SHL: 1366 FNL & 2042 FWL, Section 10 T40N R18W NMPM  
 BHL: Horizontal Well, 634 FSL & 2052 FWL, Section 3 T40N, R18W 0 deg azimuth from SHL  
 (2000' max lateral extension)  
 DOLORES CO, COLORADO

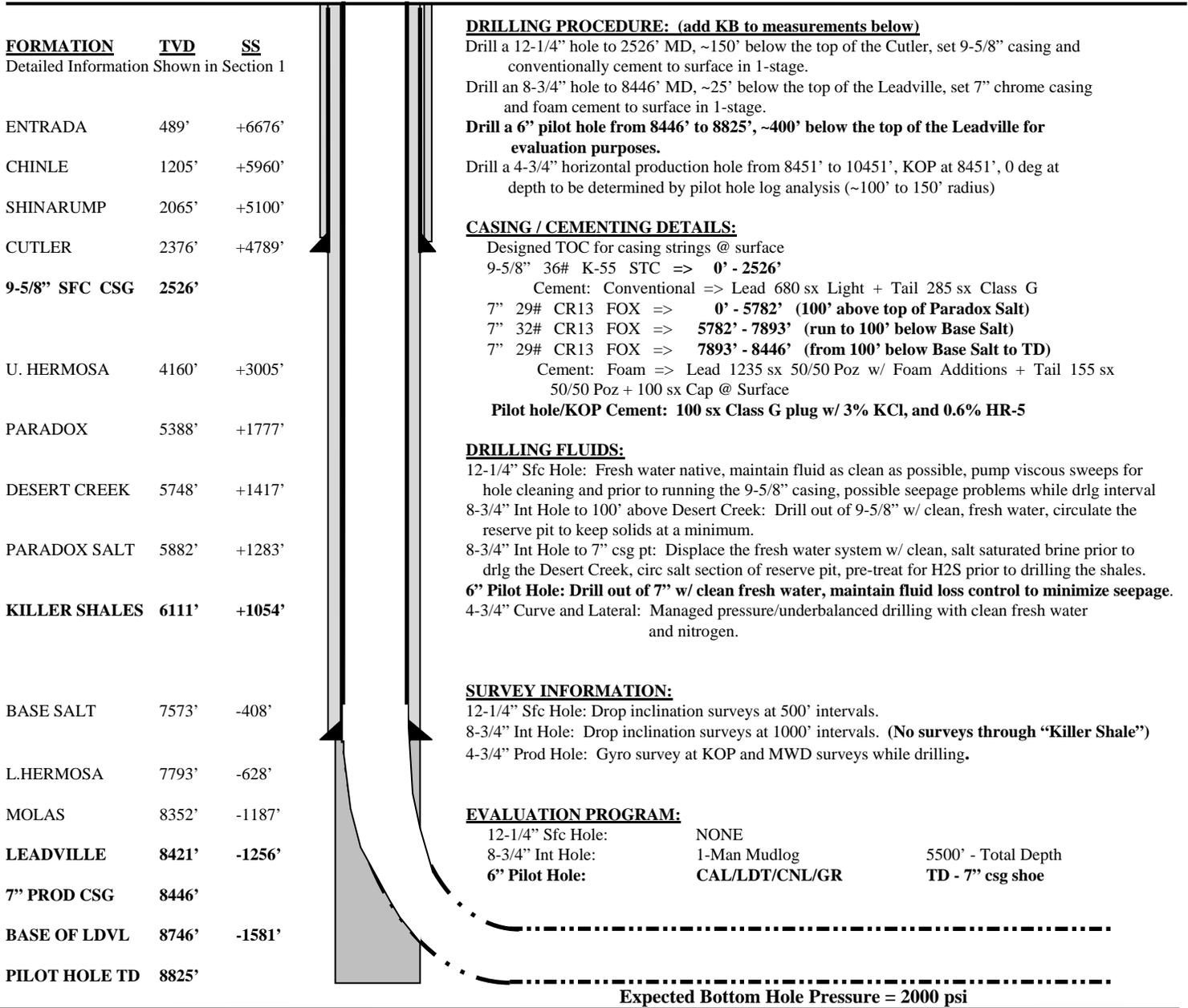
OBJECTIVE: LEADVILLE

ELEVATION: GL =7165' EST.

**A FOCUSED EFFORT WILL BE EXPECTED BY ALL PARTIES TO ELIMINATE ANY / ALL ACCIDENTS DURING THE EXECUTION OF THIS DRILLING PROJECT. H2S IS ANTICIPATED WHILE DRILLING THE KILLER SHALES.**

GEOLOGY / FORMATION TOPS

WELL PROGRAM



- OBJECTIVES:**
- 1) Focused effort by all parties to eliminate all accidents during the drilling operation
  - 2) Drill, evaluate, and case the DC-12 in less than 42 days at or under AFE.
  - 3) Successfully run the 7" chrome production casing / tubing to 25' inside the Leadville.
  - 4) Isolate the 7" 13-Chrome to surface with high quality cement.
  - 5) Drill the 4-3/4" lateral production hole w/ minimal fluid loss to the formation.

**SECTION 1 & 2 – Estimated Geologic Markers/Formations, Anticipated Fluids, and Isolation Plan**

<b>Formation</b>	<b>Top (TVD, ft)</b>	<b>Bottom (TVD, ft)</b>	<b>Composition</b>	<b>Anticipated Fluids</b>
Entrada	489	1205	Sandstone	Fresh Water
Chinle	1205	2065	Sandstone	Fresh Water
Shinarump	2065	2376	Sandstone/Shale	Fresh Water
Cutler	2376	4160	Shales	None Anticipated
Upper Hermosa	4160	5388	Carbonate	None Anticipated
Paradox	5388	5748	Carbonate/Anhydrite	None Anticipated
Desert Creek	5748	5882	Carbonate	Gas
Paradox Salt	5882	6111	Carbonate/Anhydrite	None Anticipated
Killer Shales	6111	7573	Shales	Gas, <b>Hydrogen Sulfide</b>
Base Salt	7573	7793	Carbonate/Anhydrite	None Anticipated
Lower Hermosa	7793	8352	Carbonate/Shale/Anhydrite	None Anticipated
Molas	8352	8421	Siltstones/Shale	None Anticipated
Leadville	8421	8746	Carbonate	Gas, Carbon Dioxide

9-5/8” Surface casing will be set ~100’ into the Cutler formation and cemented to surface to isolate the usable quality fresh water bearing sandstone formations above.

7” Production casing will be set 25’ into the Leadville producing formation and cemented to surface to isolate all zones above, including the killer shale section which may contain hydrogen sulfide gas.

A detailed explanation of the casing and cementing program is shown in Section 4, and a contingency plan to mitigate the hydrogen sulfide hazard is referenced in Section 7 and attached to this prognosis.

## SECTION 3 – Pressure Control Equipment

A 3M system will be utilized. The following procedures, diagrams, and guidelines are included for review with all personnel, and MUST be adhered to at all times:

- Kinder Morgan 3M BOP and Associated Equipment Installation and Testing Procedure for Doe Canyon and McElmo Dome Wells.
- Kinder Morgan BOP and Choke Manifold diagrams including minimum requirements.
- BLM 43 CFR 3160 Section III-A 3M specifications for pressure control equipment including minimum requirements.

### **3M BOP and Associated Equipment Installation and Testing Procedure**

**Kinder Morgan CO<sub>2</sub> Company, L.P.**

**Doe Canyon and McElmo Dome Wells**

\* While drilling the surface hole, a 13-3/8" 3M annular preventer with a diverter will be used.

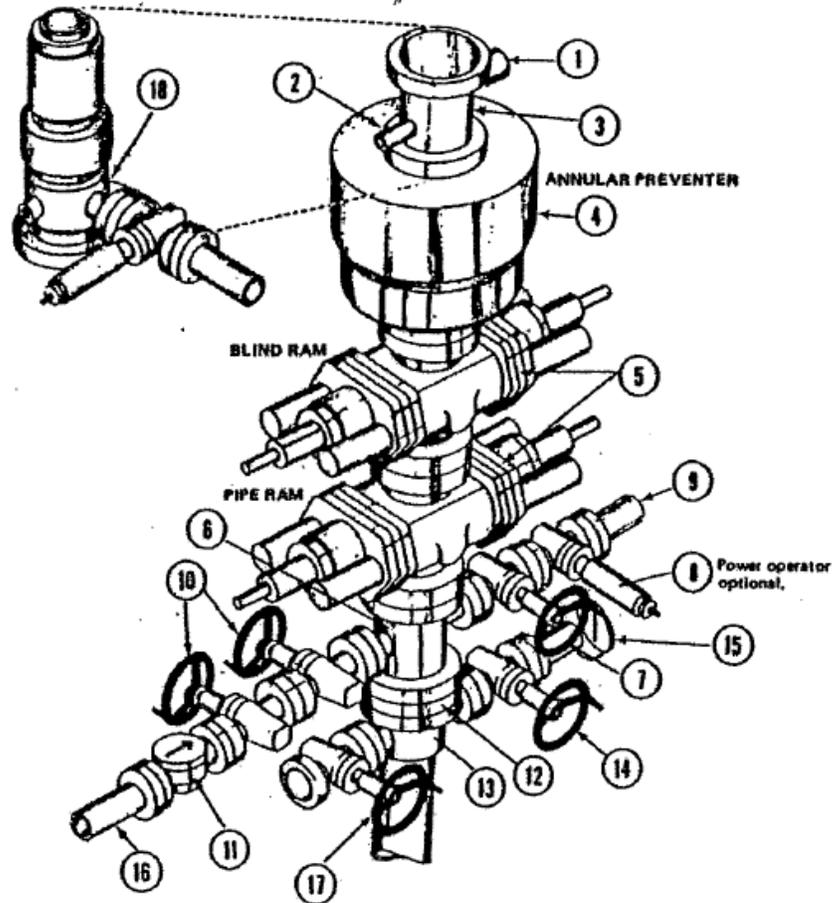
1. NIPPLE UP ON 9 5/8" X 11" 3000# SCREW ON WELLHEAD
2. INSTALL 11" X 11" 3000# SPOOL W/TWO SIDE OUTLET (4" OUTLET & 2" OUTLET)
3. INSTALL 11" 3000# SINGLE HYDRAULIC BOP (NO RAM BLOCK INSTALLED)
4. INSTALL 11" X 11" 3000# SPACER SPOOL (8" TO 10" LONG)
5. INSTALL 11" 3000# DOUBLE RAM BOP (BLIND RAMS ON TOP, PIPE RAMS ON BOTTOM)
6. INSTALL 11" 3000# HYDRIL ANNULAR BOP
7. INSTALL 11" 3000# ROTATING HEAD
8. NIPPLE UP FLOW LINES TO ROTATING HEAD
9. INSTALL 4" 3000# MANUAL VALVE ON SIDE OF SPOOL
10. INSTALL 4" 3000# HCR VALVE ON SIDE OF MANUAL VALVE
11. NIPPLE UP HCR VALVE TO 3000# CHOKE MANIFOLD (IF H<sub>2</sub>S IS EXPECTED A HYDRAULIC SUPER CHOKE SHOULD BE INSTALLED)
12. FUNCTION TEST BLIND RAMS, PIPE RAMS, HCR VALVE (USE CLEAR WATER TO TEST AND MAKE SURE ALL BOP's ARE HOOKED UP TO ACCUMULATOR AND ALL RAMS, HYDRIL AND HCR VALVE FUNCTION PROPERLY)
13. CLOSE BLIND RAMS AND TEST 9 5/8" CSG & BLIND RAMS TO 300# & 1000# PSI 30 MIN. FOR A TEST NOT UTILIZING A TEST PLUG. (IF A DECLINE OF MORE THAN 10% PERCENT IN 30 MINUTES OCCURS, THE TEST SHALL BE CONSIDERED FAILED)
14. INSTALL TEST PLUG IN 9 5/8" X 11" 3000# WELL HEAD ( WITH ALL VALVES OPEN BELOW TEST PLUG )
15. MAKE SURE BOP's ARE FULL OF WATER AND VALVES SHALL BE TESTED FROM WORKING PRESSURE SIDE DURING BOP TEST
16. CLOSE PIPE RAMS (TEST TO 300# PSI FOR 10 MINUTES & 1000# PSI FOR 10 MINUTES WITH NO PRESSURE LOST)
17. REMOVE DRILL PIPE WITH TEST PLUG IN PLACE
18. CLOSE BLIND RAMS (TEST BLIND RAMS, HCR VALVE, MANUAL VALVE & CHOKE MANIFOLD TO 300# & 3000# PSI 10 MINS)
19. OPEN BLIND RAMS, INSTALL DRILL PIPE
20. CLOSE HYDRIL ( TEST HYDRIL TO 300# PSI & 1500# PSI FOR 10 MINUTES EACH WITH NO LOST IN PRESSURE)

**\*\*\*\*\*CALL CO&G & BLM FOR ALL BOP TESTS\*\*\*\*\***

**\*\*\*\*\*ALL TESTS MUST BE CHARTED FOR CO&G & BLM\*\*\*\*\***

# KINDER MORGAN

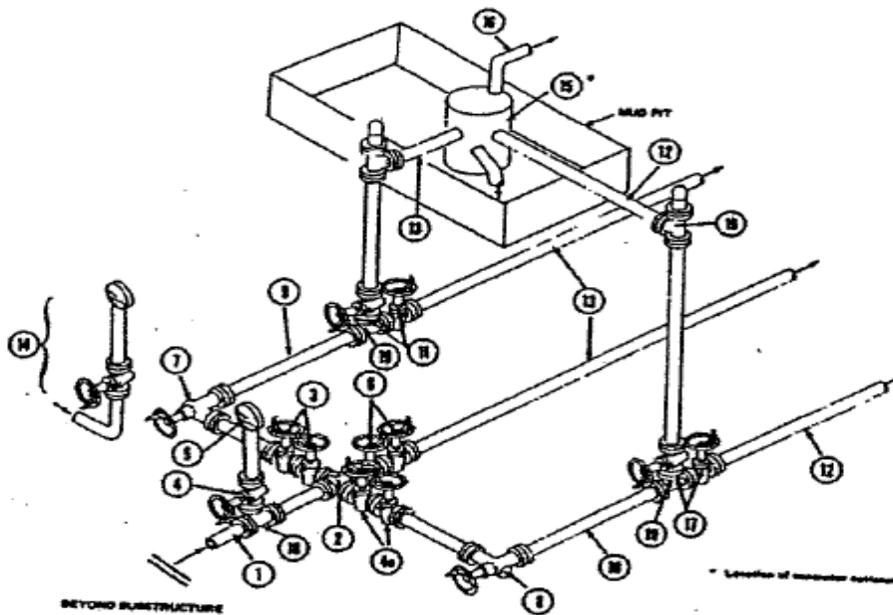
CO<sub>2</sub> COMPANY, L.P.



KINDER MORGAN MINIMUM BOP STACK REQUIREMENTS			
No.	Item	Min. I.D.	Min. Nominal
1	Flowline		7"
2	Fill up line		2"
3	Drilling nipple		
4	Annular preventer		
5	Two single or one dual hydraulically operated rams		
6	Drilling spool with 2" and 3" min. outlets		
7	Gate valve	3-1/8"	
8	Gate valve - Power Operated	3-1/8"	
9	Line to choke manifold		3"
10	Gate valve	2-1/16"	
11	Check valve	2-1/16"	
13	Casing spool		
14	Gate valve	1-13/16"	
15	Compound pressure gauge connector		
16	Kill line to rig mud pump manifold		2"

# KINDER MORGAN

CO<sub>2</sub> COMPANY, L.P.



KINDER MORGAN MINIMUM CHOKE MANIFOLD REQUIREMENTS										
No.		Class 3M			Class 5M			Class 10M		
		I.D.	Nominal	Rating	I.D.	Nominal	Rating	I.D.	Nominal	Rating
1	Line from drilling spool		3"	3,000		3"	5,000		3"	10,000
2	Cross 3"x3"x3"x2"			3,000			5,000			10,000
	Cross 3"x3"x3"x3"									
3	Gate Valves (1)	3-1/8"		3,000	3-1/8"		5,000	3-1/8"		10,000
4	Gate Valves	1-13/16"		3,000	1-13/16"		5,000	1-13/16"		10,000
4a	Valves (1)	2-1/16"		3,000	2-1/16"		5,000	2-1/16"		10,000
5	Pressure Gauge			3,000			5,000			10,000
6	Gate Valves	3-1/8"		3,000	3-1/8"		5,000	3-1/8"		10,000
7	Adjustable Choke (3)	2"		3,000	2"		5,000	2"		10,000
8	Adjustable Choke	1"		3,000	1"		5,000	1"		10,000
9	Line		3"	3,000		3"	5,000		3"	10,000
10	Line		2"	3,000		2"	5,000		2"	10,000
11	Gate Valves	3-1/8"		3,000	3-1/8"		5,000	3-1/8"		10,000
12	Lines		2"	3,000		2"	5,000		2"	10,000
13	Lines		3"	3,000		3"	5,000		3"	10,000
14	Remote reading standpipe compound pressure gauge, valve and line			3,000			5,000			10,000
15	Gas Separator		16"	3,000		16"	5,000		16"	10,000
16	Line		4"	3,000		4"	5,000		4"	10,000
17	Gate Valves	2-1/16"		3,000	2-1/16"		5,000	2-1/16"		10,000
18	Tee 3"x3"x2"			3,000			5,000			10,000
19	Tee 3"x3"x3"			3,000			5,000			10,000

- (1) Only one required in Class 3M
- (2) Gate Valves only shall be used for Class 10M
- (3) Remote operated hydraulic choke required on Class 10M
- (4) Requirements are for new manifolds. Existing manifolds may continue to have a working pressure of the manifold section downstream of the first valve beyond the choke through the last valve in any run of not less than 25% of the working pressure of the choke, providing they are conspicuously marked "CAUTION - LOW PRESSURE VALVE. DO NOT CLOSE AGAINST WELL PRESSURE"
- (5) Items no. 18 and 2 can be combined as 5 way cross

#### EQUIPMENT SPECIFICATIONS AND INSTALLATION INSTRUCTION

1. All connections in choke manifold shall be welded, studded, flanged or Cameron clamp of comparable rating.
2. All flanges shall be API 6B or 6BX and ring gaskets shall be RX or BX.
3. All lines shall be securely anchored.
4. Chokes shall be equipped with tungsten carbide seats and needles, and replacements shall be available.
5. Choke manifold pressure and standpipe pressure gauges shall be available at the choke manifold to assist in regulating chokes. As an alternate with automatic chokes, a choke manifold pressure gauge shall be located on the rig floor in conjunction with the standpipe pressure gauge
6. Line from drilling spool to choke manifold should be as straight as possible. Lines downstream from chokes shall make turns by large bends or 90 bends using bull plug tees.
7. Discharge lines from chokes, choke bypass and from top of gas separator should vent as far as practical from the well.

**BUREAU OF LAND MANAGEMENT**  
**43 CFR 3160**

Federal Register / Vol. 53, No. 223  
Friday, November 18, 1988  
Effective date: December 19, 1988

**Onshore Oil and Gas Operations; Federal and Indian Oil and Gas Leases;**  
**Onshore Oil and Gas Order No. 2, Drilling Operations**

**III. Requirements**

**A. Well Control Requirements**

1. Blowout preventer (BOP) and related equipment (BOPE) shall be installed, used, maintained, and tested in manner necessary to assure well control and shall be in place and operational prior to drilling the surface casing shoe unless otherwise approved by the APD. Commencement of drilling without the approved BOPE installed, unless otherwise approved, shall subject the operator to immediate assessment under 43 CFR 3163.1(b)(1). The BOP and related control equipment shall be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE shall be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. The working pressure of all BOPE shall exceed the anticipated surface pressure to which it may be subjected, assuming a partially evacuated hole with a pressure gradient of 0.22 psi/ft.

2. The gravity of the violations for many of the well control minimum standards listed below are shown as minor. However, very short abatement periods in this Order are often specified in recognition that by continuing to drill, the violation which was originally determined to be of a minor nature may cause or threaten immediate, substantial and adverse impact on public health and safety, the environment, production accountability, or royalty income, which would require it reclassification as a major violation.

a. Minimum standards and enforcement provisions for well control equipment.

i. A well control device shall be installed at the surface that is capable of complete closure of the well bore. This device shall be closed whenever the well is unattended.

iii. 3M system:

- Annular preventers\*
- Double ram with blind rams and pipe rams\*
- Drilling spool, or blowout preventer with 2 side outlets (choke side shall be a 3-inch minimum diameter, kill side shall be at least 2-inch diameter)\*
  
- Kill line (2 inch minimum)
- A minimum of 2 choke line valves (3 inch minimum)\*
- 3 inch diameter choke line
- 2 kill line valves, one of which shall be a check valve (2 inch minimum)\*
  
- 2 chokes (refer to diagram in Attachment 1)
- Pressure gauge on choke manifold
- Upper kelly cock valve with handle available
- Safety valve and subs to fit all drill string connections in use
- All BOPE connections subjected to well pressure shall be flanged, welded, or clamped\*
- Fill-up line above the uppermost preventer.

vi. If repair or replacement of the BOPE is required after testing, this work shall be performed prior to drilling out the casing shoe.

vii. When the BOPE cannot function to secure the hole, the hole shall be secured using cement, retrievable packer or a bridge plug packer, bridgeplug, or other acceptable approved method to assure safe well conditions.

b. Minimum standards and enforcement provisions for choke manifold equipment.

i. All choke lines shall be straight lines unless turns use tee blocks or are targeted with running tees, and shall be anchored to prevent whip and reduce vibration.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

ii. Choke manifold equipment configuration shall be functionally equivalent to the appropriate example diagram shown in Attachment 1 of this Order. The configuration of the chokes may vary.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: Prompt correction required.

iii. All valves (except chokes) in the kill line choke manifold, and choke line shall be a type that does not restrict the flow (full opening) and that allows a straight through flow (same enforcement as item ii).

iv. Pressure gauges in the well control system shall be a type designed for drilling fluid service (same enforcement as above).

[57 FR 3025, Jan. 27, 1992]

c. Minimum standards and enforcement provisions for pressure accumulator system.

i. 2M system accumulator shall have sufficient capacity to close all BOP's and retain 200 psi above precharge. Nitrogen bottles that meet manufacturer's specifications may be used as the backup to the required independent power source.

Violation: Minor.

Corrective Action: Install the equipment as specified.

Normal Abatement Period: 24 hours.

ii. 3M system accumulator shall have sufficient capacity to open the hydraulically-controlled choke line valve(if so equipped), close all rams plus the annual preventer, and retain a minimum of 200 psi above precharge on the closing manifold without the use of the closing pumps. this is a minimum requirement. The fluid reservoir capacity shall be double the usable fluid volume of the accumulator system capacity and the fluid level shall be maintained at the manufacturer's recommendations. The 3M system shall have 2 independent power sources to close the preventers.

Nitrogen bottles (3 minimum) may be 1 of the independent power sources and, if so, shall maintain a charge equal to the manufacturer's specifications.

d. Minimum standards and enforcement provisions for accumulator precharge pressure test. This test shall be conducted prior to connecting the closing unit to the BOP stack and at least once every 6 months. The accumulator pressure shall be corrected if the measured precharge pressure is found to be above or below the maximum or minimum limit specified below (only nitrogen gas may be used to precharge):

Accumulator working pressure rating	Minimum acceptable operating pressure	Desired precharge pressure	Maximum acceptable precharge pressure	Minimum acceptable precharge pressure
1,500 psi	1,500 psi	750 psi	800 psi	700 psi
2,000 psi	2,000 psi	1,000 psi	1,100 psi	900 psi
3,000 psi	3,000 psi	1,000 psi	1,100 psi	900 psi

e. Minimum standards and enforcement provisions for power availability. Power for the closing unit pumps shall be available to the unit at all times so that the pumps shall automatically start when the closing valve manifold pressure has decreased to the pre-set level.

f. Minimum standards and enforcement provisions for accumulator pump capacity. Each BOP closing unit shall be equipped with sufficient number and sizes of pumps so that, with the accumulator system isolated from service, the pumps shall be capable of opening the hydraulically-operated gate valve (if so equipped), plus closing the annular preventer on the smallest size drill pipe to be used within 2 minutes, and obtain a minimum of 200 psi above specified accumulator precharge pressure.

g. Minimum standards and enforcement provisions for locking devices. A manual locking device (i.e., hand wheels) or automatic locking devices shall be installed on all systems of 2M or greater. A valve shall be installed in the closing line as close as possible to the annular preventer to act as a locking device. This valve shall be maintained in the open position and shall be closed only when the power source for the accumulator system is inoperative.

h. Minimum standards and enforcement provisions for remote controls. Remote controls shall be readily accessible to the driller. Remote controls for all 3M or greater systems shall be capable of closing all preventers. Remote controls for 5M or greater systems shall be capable of both opening and closing all preventers. Master controls shall be at the accumulator and shall be capable of opening and closing all preventers and the choke line valve (if so equipped). No remote control for a 2M system is required.

i. Minimum standards and enforcement provisions for well control equipment testing.

i. Perform all tests described below using clear water or an appropriate clear liquid for subfreezing temperatures with a viscosity similar to water.

ii. Ram type preventers and associated equipment shall be tested to approved (see item I.D.1. of this order) stack working pressure if isolated by test plug or to 70 percent of internal yield pressure of casing if BOP stack is not isolated from casing. Pressure shall be maintained for at least 10 minutes or until requirements of test are met, whichever is longer. If a test plug is utilized, no bleed-off of pressure is acceptable. For a test not utilizing a test plug, if a decline in pressure of more than 10 percent in 30 minutes occurs, the test shall be considered to have failed. Valve on casing head below test plug shall be open during test of BOP stack.

iii. Annular type preventers shall be tested to 50 percent of rated working pressure. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.

iv. As a minimum, the above test shall be performed:

- A. when initially installed;
- B. whenever any seal subject to test pressure is broken;
- C. following related repairs; and
- D. at 30-day intervals.

v. Valves shall be tested from working pressure side during BOPE tests with all down stream valves open.

vi. When testing the kill line valve(s), the check valve shall be held open or the ball removed.

vii. Annular preventers shall be functionally operated at least weekly.

viii. Pipe and blind rams shall be activated each trip, however, this function need not be performed more than once a day.

ix. A BOPE pit level drill shall be conducted weekly for each drilling crew.

x. Pressure tests shall apply to all related well control equipment.

xi. All of the above described tests and/or drills shall be recorded in the drilling log.

Violation: Minor.

Corrective action: Perform the necessary test or provide documentation.

Normal Abatement Period: 24 hours or next trip, as most appropriate.

## SECTION 4 – Drilling Equipment, Casing, and Cementing Programs

### PROSPECT INFORMATION

The DC-12 will be one of three wells to be drilled during the 2012 drilling program at Doe Canyon. The wellplan calls for the 9-5/8" X 7" casing program (tubingless openhole completion) that has been used successfully since being implemented in 1996.

### WELL OBJECTIVE

The main objectives for the drilling operation on the DC-12 are:

1. Maintain a focused effort by everyone on location to eliminate all accidents.
2. Drill, evaluate, case and complete (horizontal leg of 2000') the well in less than 42 days at or under AFE.
3. Run a full string of 7" 13-Chrome production casing to 25' below the top of the Leadville formation.
4. Isolate the 7" 13-Chrome to surface with high quality cement.
5. Drill the 4-3/4" horizontal production hole with minimal fluid loss / damage to the formation. The lateral is planned to be drilled using managed pressure drilling techniques if circulation is lost. Underbalanced drilling is a contingency to this plan.

### POTENTIAL PROBLEMS

The main problems for the DC-12 are the typical problems expected while drilling in the area:

1. **Lost Circulation in the 12-1/4" Surface Hole:** Lost circulation can be expected at any depth while drilling the surface hole. Maintain a clean fresh water system, circulating the reserve pit, while drilling this hole section. Pump LCM pills as required to control the losses. No losses in surface hole were encountered on offsets.
2. **Gas Kick from the Desert Creek @ 5748':** Gas kicks have been encountered while drilling the Desert Creek formation. A planned mud weight schedule will be utilized to help minimize the chance of kicks in this section.
3. **Gas and H2S from the Killer Shales:** Geo-pressured shales from the P4 on down will contain varying amounts of gas and associated H2S. Circulate the salt water portion of the reserve pit to remove excess gas. Pre-treat the mud using H2S scavenger for H2S contamination.
4. **Stuck Pipe in the Killer Shales:** The Killer Shale is a high pressure, low volume shale which "flows" into the well causing stuck pipe. An attached list of recommendations for drilling the Killer Shale, titled "Paradox Salt Drilling Procedure", is located in the mud section of this program. The recommendations have proven to be very successful in recent drilling programs and are strongly recommended they be followed. Educate the drillers prior to drilling the killer shale and discuss in detail the procedure for drilling the shale.
5. **Lost Circulation in the Lower Hermosa:** Lost circulation problems have been encountered during the production casing cement job in the Lower Hermosa. The fracture gradient is estimated at 12 ppg. The problem has been successfully eliminated with single stage foam cementing.
6. **Pilot Hole Cementing Pipe:** The pilot hole cement plug should not be over 100 sks. If the first plug does not fill into the casing, spot a second plug which does not exceed 50 sks. Over-displacement is reservoir-dependent.

## GENERAL DRILLING PROCEDURE

14" conductor pipe will be set at ~80' prior to moving in the drilling rig. It is necessary to rig up a 13-3/8" 3M annular preventer with diverter to drill the surface hole.

A 12-1/4" hole will be drilled from surface to 2526', located approximately 100' to 150' below the top of the Cutler. A full string of 9-5/8" surface casing will be run to 2526' with cement circulated to surface. The 9-5/8" surface casing will protect the groundwater in the area and isolate the Shinarump formation. After the casing is run and cemented, screw on the 9-5/8" X 11" 3M casing head housing and nipple-up the 11" 3M BOP. Wait on cement 12 hours and pressure test the casing to 1500 psi and the BOP's to their rating prior to drilling out.

An 8-3/4" hole will be drilled out from the surface casing point to the 7" production casing point at 8446', located 25' into the Leadville formation. The casing point will be picked by the mud-logger and/or MWD gamma ray (GR) that will be picked up at 7893' after drilling the Killer Shales. No wireline logs will be run at casing point. A full string of 7" 13-Chrome casing will be run and set 25' into the Leadville. The 7" casing will be cemented back to surface in one stage with foam cement. The well integrity is dependent on the casing being handled and run correctly. 7" 13CR requires special handling and is to be handled according to the procedures specified on site.

A 6" pilot hole will be drilled out from the 7" production casing to 400' below the Leadville top. Drop a Gyro at TD of the pilot hole on trip out of hole. The pilot hole will then be logged from TD to 500' inside the 7" casing shoe. The pilot hole will be cemented and KOP dressed off 5' below the casing shoe. If significant lost circulation occurs while drilling the pilot hole, a two-stage cement plug/squeeze with a cement retainer will be considered.

A 4-3/4" horizontal hole will be drilled out from the KOP to TD. The build rate and target elevation of the lateral will be determined from pilot log analysis, usually ~100 to 150 ft below the top of the Leadville. A string of 2-7/8" drill pipe will be picked up and a 4-3/4" hole will be drilled to a vertical section operational target of 500' to 2000'. A directional drilling plan is attached to this prognosis.

## SURVEY DETAIL

Normal well deviation is not a concern.

### Inclination surveys :

- 500' intervals from spud to the 9-5/8" casing point and
- ~1000' intervals from below the 9-5/8" casing point to the top of the Paradox Salt
- **Do not drop surveys while drilling below the Paradox Salt due to potential sticking**
- Drop a gyro survey at TD of the pilot hole section- used to build the final directional plan for lateral
  - Directional company will also use a Gyro to help orient for kick off and assume KOP 5' below 7" csg point
  - Leadville target depth will be picked from Triple Combo & Saturation Curve logs run in 6.0" pilot hole
- Surveys can be taken inside the 2-7/8" drillstring after the 7" casing is run.
- A gyro survey will be run at KOP and MWD surveys will be taken while drilling the horizontal section.

## CASING DETAIL

## CASING RATING / DESIGN FACTORS

<u>SIZE</u>	<u>INTERVAL</u>	<u>DESCRIPTION</u>	<u>COLLAPSE</u>	<u>BURST</u>	<u>TENSION</u>
9-5/8"	0' – 2526'	36# K-55 STC	2020 / 1.25	3520 / 1.63	423 / 4.5
7"	0' – 5782'	29# CR13 FOX	7020 / 2.2	8160 / 2.9	676 / 4.6 (100' above top of Paradox Salt)
7"	5782' – 7893'	32# CR13 FOX	8600 / 1.01	9060 / 3.1	692 / 3.99 (run to 100' below Base Salt)
7"	7893' – 8446'	29# CR13 FOX	7020 / 1.7	8160 / 2.8	676 / 3.42 (from 100' below Base Salt to TD)

All of the 32# CR13 casing will be coated with Rytwrap (ICO in Odessa) prior to arriving on location.

## DESIGN ASSUMPTIONS:

9-5/8" Surface	Tension:	Buoyed weight in 8.4 ppg fresh water, DF = 1.6
	Collapse:	Full evacuation w/ 9.0 ppg on outside, DF = 1.0
	Burst:	2000 psi shut in pressure at the surface, DF = 1.33
7" Production	Tension:	Buoyed weight in 10.0 ppg brine
	Collapse:	Full evacuation in 10.0 ppg brine for 29#, 1.0 psi/ft for 32#
	Burst:	2500 psi shut in pressure at the surface with 10.0 ppg inside

and 9.0 ppg outside

## CEMENTING PROCEDURE

### 9-5/8" SURFACE CASING => 1-stage

Use API 8-3/4" drift on location

Shoe Type: Regular Guide Shoe  
Collar Type: Regular Float collar, 40' above shoe  
Centralizers: 18 required => Place centralizers on shoe joint, and every 4th joint to surface  
Flag Joints: None Required  
Other Equipment: Stop clamp, thread lock the bottom 2 joints of casing + all float equipment, top and bottom plugs

Reciprocate: Not required, limit of 264,000 lbs based on 36# K-55 STC w/ a 1.6 SF

Preflush: 40 bbls => Fresh water @ 10 bbls / min

**Lead CMT Slurry:** 680 sks => Light Premium => 5 lbm/sk Gilsonite (LC) + 0.125 lbm/sk Poly E Flake (LC) + 0.5% Halad®-9  
Specifications: 12.4 ppg / 1.87 ft<sup>3</sup> / sk / 9.36 gal / sk  
**100% Excess**

**Tail CMT Slurry:** 285 sks => Premium Cement => 94 lbm/sk Class G Cement + 0.125 lbm/sk Polyflake (LC) + 0.2% Halad®-9  
Specifications: 15.6 ppg / 1.18 ft<sup>3</sup> / sk / 5.19 gal / sk  
**100% Excess**

**Displacement:** ~250 bbls => Fresh Water @ 8 - 10 bbls / min

Volume Based: All volumes listed are estimates only, for calculations use 12-1/4" X 9-5/8" annulus + 100% excess + shoe joints + ~100 sks circulated @ surface, attempt to circulate cement to surface, excess volume is based on experience.

Pressure Limits: 2000 psi while pumping or bumping plug due to collapse rating of the 9-5/8" 36# K-55 STC w/ a 1.0 SF

Test Required: Lab test w/ field water, want a 2 hr minimum @ 105° BHST

Temperature Survey: Required if cement does not circulate at surface, call Todd Gentles @ (713) 369-8487 or 713-249-2805 for details

Wellhead: Install section "A" assembly

Special Note:

1. Report the volume of cement circulated to the surface.
2. WOC for a minimum of 12 hours prior to drilling out.
3. NU 3M - 11 - BOP and test to rating.
4. Test the casing to 500 psi.
5. Cement Co. => Send copy of pressure charts, job log and summary to: Kinder Morgan, Attn: Todd Gentles, 500 Dallas, Suite 1000, Houston, TX 77002.

## CEMENTING PROCEDURE

7" PRODUCTION CASING => Single stage foam

Shoe Type: Differential Fill Float Shoe  
Collar Type: Differential Fill Float Collar, 80' above shoe  
Centralizers: 65 required => 10' above shoe and every other joint  
Flag Joints: Cross overs from 29# to 32# will serve as flag joints

Other Equipment: Thread lock the bottom 3 joints of casing + all float equipment.

Reciprocate: If required, limit @ 100,000 lbs

Preflush: 40 bbls => Fresh water @ 10 bbls / min  
10 bbls => Water Spacer  
30 bbls => Mud flush  
10 bbls => Fresh water

Lead Slurry: 1235 sks => 50/50 Poz Standard => 0.2% Versaset + 0.15% Halad-766 + 1.5% Chem-Foamer 760  
Specifications: 13.0 ppg / 1.44 ft<sup>3</sup> / sk / 6.76 gal / sk  
50% Excess

Tail Slurry: 155 sks => 50/50 Poz Standard => 0.25% Halad-766 + 0.2% Versaset  
Specifications: 13.5 ppg / 1.28 ft<sup>3</sup> / sk / 5.73 gal / sk  
50% Excess

Cement Cap Slurry: 100 sks => Premium Cement => 94lbm/sk Class G Cement + 2% CaCl<sub>2</sub>  
Specifications: 15.6 ppg / 1.20 ft<sup>3</sup> / sk / 5.26 gal / sk

Displacement: ~300 bbls freshwater @ 8 - 10 bbls / min

Volume Based: Use 9" hole diameter to calculate cement volume

Test Required: Lab test w/ field water, 3.25 hr minimum @ 200° BHST  
Lab test w/ field water, 3.50 hr minimum @ 170° BHST

Temperature Survey: Possible survey if severe lost circulation occurs

Wellhead: Install section "B" assembly

Special Note:

1. Circulate 3 annular volumes prior to cementing @ maximum rate possible.
2. Displace cement at the maximum rate possible.
3. Report volumes of cement circulated.
4. Report any circulation problems on the morning report.
5. Cement Co. => Send copy of pressure charts, job log and summary to:  
Kinder Morgan, Attn: Todd Gentles, 500 Dallas, Suite 1000, Houston, TX 77002.

## **SECTION 5 – Mud Program**

The “standard” mud program and procedures used during the previous drilling programs at McElmo Dome will be employed during the drilling operation of the well.

### **Surface - 2526’ (9-5/8” Casing Point):**

Hole Size: 12-1/4”  
Mud Type: Fresh water

Spud the 12-1/4” surface hole with fresh water and circulate the fresh water section of the reserve pit. Maintain the fluid as clean as possible to help prevent lost circulation. Use paper to control any seepage and pump LCM sweeps if lost circulation becomes a problem. Pump viscous sweeps if tight connections are encountered and prior to running the 9-5/8” casing.

### **2526’ - 5648’ (100’ above the Desert Creek):**

Hole Size: 8-3/4”  
Mud Type: Fresh water  
Problems: Seepage, hole cleaning

Drill out of the 9-5/8” casing with clean fresh water. Circulate the reserve pit to keep solids to a minimum. Sweep the hole as required for hole cleaning and / or lost circulation problems. Use paper to control any seepage problems.

### **5648’ – 8446’ (25’ into the Leadville / 7” Casing Point):**

Hole Size: 8-3/4”  
Mud Type: Salt saturated brine  
pH: 11+, as required to control H2S  
Problems: H2S, killer Shale gas influx, hole cleaning

Displace the fresh water system with salt saturated brine 100’ above the Desert Creek formation. Circulate through the salt water section of the reserve pit to maintain a clean fluid and to assist in breaking out any entrained gas. Pre-treat mud for H2S prior to drilling the P4 Shale.

Follow the attached guidelines for drilling the Killer Shale, titled “Paradox Salt Drilling Procedure”, which is located at the back of this prognosis. The recommendations have proven to be very successful in recent drilling programs.

### **8446’ – 8825’ (Pilot Hole) and 8451’ – 10451’ (Lateral ~2000’):**

Hole Size: 6” & 4-3/4”  
Mud Type: Fresh water / Baradril-N Sweeps  
pH: 9-9.5 with caustic soda  
Problems: LC, Hole cleaning, Lubricity

Build 400-500 bbls Freshwater/Bardril-N for sweeps. Expect complete losses while drilling the lateral. Circulate 20-30 Bardril-N sweeps each stand drilled to keep cuttings moving up the hole. Add Enviro-Torque with each sweep for lubricity. Circulate 10 bbls 15% BDF-408 while drilling to prevent cuttings bed build-up.

If circulation is lost and unable to be regained, nitrogen will be added to the mud system to help lift the fluid for circulation and cuttings movement. A specific description of this process is discussed in Section 8 of this prognosis.

## **SECTION 6 – Evaluation Program**

Mud logging services will be used from 5500’ to TD.

A measure while drilling (MWD) tool with gamma ray (GR) capability will be run from 7893’ to casing point. GR response, mud logs, and penetration rate will be used to determine the top of the Leadville formation and final casing point.

The 6” pilot hole will be logged with three runs as follows:

- 1st run induction
- 2nd run density
- 3rd run neutron and GR

## **SECTION 7 – Expected Pressures and Identified Hazards**

### **BOTTOM HOLE PRESSURE**

The Leadville formation bottom hole pressure is 2400 psi in the Doe Canyon area. Given the well depths of approximately 8425', a fresh water column provides approximately 3650 psi for well control.

### **H2S POTENTIAL**

H2S is expected to be circulated to the surface during the drilling of the Killer Shales interval located at 6111' - 7573'. The H2S contingency plan that was used in the previous programs has been updated and revised and will be in force. All the necessary precautions, drills, and training will be done to protect personnel on location. H2S monitors and safety equipment will be on location and operational prior to drilling the section and remain until rig release.

## **SECTION 8 – Other Items**

### **LOST CIRCULATION CONTINGENCY PLAN**

Circulation may be lost in the 4-3/4" horizontal production hole. In this situation, managed pressure drilling techniques will be implemented. A normal fresh water fluid column of water is approximately 3,650 psi downhole pressure, and the reservoir pressure is 2,400 psi - therefore an overbalanced condition exists. The fracture gradient of the formation is estimated at 0.6 to 0.7 psi/ft, which equates to approximately 5,050 to 5,900 psi downhole pressure, which indicates fractures are not being induced; however, when a high porosity zone is encountered in the Leadville, and the pore volume exists to take the fluid. At this point, there is a high probability of sticking drill pipe as the cuttings flowing up the annulus immediately fall back.

A nitrogen managed pressure drilling package will be on standby on location while drilling the curve and lateral should this situation occur. The nitrogen will be added into the mud system to lighten the hydrostatic pressure and regain circulation in a managed pressure scenario. Managed pressure drilling equipment will be used to handle the return flow of nitrogen and any influx of CO<sub>2</sub> gas through a separator and vent stack. Well control is maintained by reducing or stopping the flow of nitrogen, which will kill the well. A dedicated rig pump and kill line are also hooked up and ready to boost the water flow if needed. Well control is also a critical part of the managed pressure drilling process; the measure while drilling (MWD) tool has a pressure while drilling (PWD) sensor which feeds into the managed pressure drilling control system. The bottom hole pressure is constantly monitored to ensure the fluid column is sufficient to control the well and is used to adjust the water and nitrogen mix to maintain circulation while drilling. An "at balance" situation is the desired scenario.

In the event that the managed pressure system does not help regain circulation and carry cuttings out of the hole, the lateral will be stopped short of the maximum target length of 2000'.

**WELL PROGNOSIS OVERVIEW**

This well prognosis is organized to follow the Bureau of Land Management (BLM) Eight Point Drilling Plan referenced in the Onshore Order #1. The Eight Points correspond to the following Eight Sections of the Prognosis

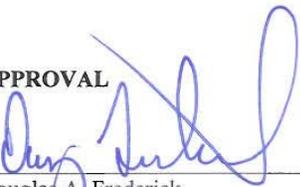
1. **Estimated Geologic Markers/Formations** - Estimated tops of important geological markers and formations.
2. **Anticipated Fluids and Isolation Plan** - Estimated depths at which top and bottom of anticipated water (particularly fresh water), oil, gas or other mineral-bearing formations are expected to be encountered and the lessee's or operator's plans for protecting such resources.
3. **Pressure Control Equipment** - Lessee's or operator's minimum specifications for pressure control equipment to be used and a schematic diagram thereof showing sizes, pressure ratings (or API series), and the testing procedures and testing frequency
4. **Drilling Equipment, Casing, and Cementing Programs** - Any supplementary information more completely describing the drilling equipment and casing program.
5. **Mud Program** - Type and characteristics of the proposed circulating mechanism to be employed in drilling, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the mud system.
6. **Evaluation Program** - The anticipated type and amount of testing, logging and coring.
7. **Expected Pressures and Identified Hazards** - The expected bottom hole pressure and any anticipated abnormal pressures or temperatures or potential hazards, such as hydrogen sulfide, expected to be encountered, along with contingency plans for mitigating such identified hazards.
8. **Other Items** - Any other facets of the proposed operations which the lessee or operator wishes to point out for BLM's consideration of the application.

Three attachments are referenced in sections of the document

1. Paradox Salt Drilling Procedure
2. H2S Contingency Plan
3. Directional Well Plan

<u>CONTACT INFORMATION</u>	<u>OFFICE</u>	<u>CELL</u>
Operations Manager – Todd Gentles	713-369-8487	713-249-2805
Drilling Director – Doug Frederick	713-369-9208	281-421-2333
Drilling Engineer – Valerie Cawthorn	713-369-8509	281-798-8769
Geologist – Ernest Nuckols	713-369-8821	361-563-6451

**APPROVAL**

  
\_\_\_\_\_  
Douglas A. Frederick  
Drilling Director  
Kinder Morgan CO2 Company, L.P.