D R I L L I N G   P R O G N O S I S

WELL: **GOODMAN POINT #15 (GP #15)** **FIELD: McElmo Dome**

LOCATION: **SHL: 660 FNL & 1978 FEL, Section 18 T36N R17W NMPM**
BHL: Horizontal Well, 2066 FNL & 1902 FWL, Section 18 T36N, R17W 225 deg azimuth from SHL (2000' max lateral extension)
MONTEZUMA CO, COLORADO

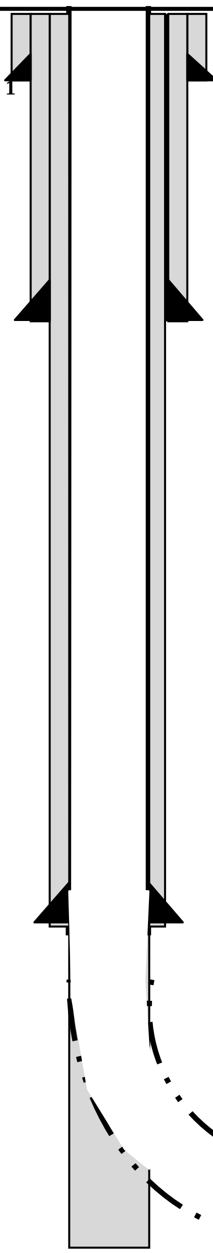
OBJECTIVE: LEADVILLE **ELEVATION: GL =7012' EST.**

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

Detailed Information Shown in Section 1

FORMATION	**TVD**	**SS**
ENTRADA	1097'	+5895'
CHINLE	2002'	+4990'
SHINARUMP	2692'	+4300'
CUTLER	2864'	+4128'
9-5/8" SFC CSG	**2964'**	
U. HERMOSA	4560'	+2432'
PARADOX	5487'	+1505'
DESERT CREEK	5754'	+1238'
PARADOX SALT	5915'	+1077'
KILLER SHALES	**6436'**	**+556'**
BASE SALT	7344'	-352'
L.HERMOSA	7605'	-613'
MOLAS	7716'	-724'
LEADVILLE	**7832'**	**-840'**
7" PROD CSG	**7857'**	
BASE OF LEADVILLE		**8092'**



WELL PROGRAM

DRILLING PROCEDURE: (add KB to measurements below)

Drill a 12-1/4" hole to 2964' MD, ~100' below the top of the Cutler, set 9-5/8" casing and conventionally cement to surface in 1-stage.
Drill an 8-3/4" hole to 7857' MD, ~25' below the top of the Leadville, set 7" chrome casing and foam cement to surface in 1-stage.
Drill a 6.0" pilot hole from 7857' to 7956', ~200' below the top of the Leadville for evaluation purposes.
Drill a 4-3/4" horizontal production hole from 7862' to 9862', KOP at 7862', 225 deg at depth to be determined by pilot hole log analysis (~100' to 150' radius)

CASING / CEMENTING DETAILS:

Designed TOC for casing strings @ surface
9-5/8" 36# K-55 STC => **0' - 2964'**
Cement: Conventional => Lead 800 sx 50/50 Poz + Tail 300 sx Class G
7" 29# CR13 FOX => **0' - 5815' (100' above top of Paradox Salt)**
7" 32# CR13 FOX => **5815' - 7444' (run to 100' below Paradox Salt)**
7" 29# CR13 FOX => **7444' - 7857' (from 100' below Paradox Salt to TD)**
Cement: Foam => Lead 1380 sx Base Slurry w/ Foam Additions + Tail 290 sx Class G + 100 sx Cap @ Surface
Pilot hole/KOP Cement: 100 sx Class C plug w/ 0.3% KCl, 0.3% HR-5, and 0.15% HR-25

DRILLING FLUIDS:

12-1/4" Sfc Hole: Fresh water native, maintain fluid as clean as possible, pump viscous sweeps for hole cleaning and prior to running the 9-5/8" casing, possible seepage problems while drlg interval
8-3/4" Int Hole to 100' above Desert Creek: Drill out of 9-5/8" w/ clean, fresh water, circulate the reserve pit to keep solids at a minimum.
8-3/4" Int Hole to 7" csg pt: Displace the fresh water system w/ clean, salt saturated brine prior to drlg the Desert Creek, circ salt section of reserve pit, pre-treat for H2S prior to drilling the shales.
6.0" Pilot Hole: Drill out of 7" w/ clean fresh water, maintain fluid loss control to minimize seepage.
4-3/4" Curve and Lateral: Managed pressure/underbalanced drilling with clean fresh water and nitrogen.

SURVEY INFORMATION:

12-1/4" Sfc Hole: Drop inclination surveys at 500' intervals.
8-3/4" Int Hole: Drop inclination surveys at 1000' intervals. **(No surveys through "Killer Shale")**
4-3/4" Prod Hole: Gyro survey at KOP and MWD surveys while drilling**.**

EVALUATION PROGRAM:

12-1/4" Sfc Hole:	**NONE**	
8-3/4" Int Hole:	**2-Man Mudlog**	**5500' - Total Depth**
6.0" Pilot Hole:	**CAL/LDT/CNL/GR**	**TD - 7" csg shoe -triple combo**

Expected Bottom Hole Pressure = 2000 psi

OBJECTIVES:
1) **Focused effort by all parties to eliminate all accidents during the drilling operation**
2) **Drill, evaluate, and case the GP #15 in less than 26 days at a cost of $3,850,000 or less.**
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

Formation	Top (TVD, ft)	Bottom (TVD, ft)	Composition	Anticipated Fluids
Entrada	1097	2002	Sandstone	Fresh Water
Chinle	2002	2692	Sandstone	Fresh Water
Shinarump	2692	2864	Sandstone/Shale	Fresh Water
Cutler	2864	4560	Shales	None Anticipated
Upper Hermosa	4560	5487	Carbonate	None Anticipated
Paradox	5487	5754	Carbonate/Anhydrite	None Anticipated
Desert Creek	5754	5915	Carbonate	Gas
Paradox Salt	5915	6436	Carbonate/Anhydrite	None Anticipated
Killer Shales	6436	7344	Shales	Gas, **Hydrogen Sulfide**
Base Salt	7344	7605	Carbonate/Anhydrite	None Anticipated
Lower Hermosa	7605	7716	Carbonate/Shale/Anhydrite	None Anticipated
Molas	7716	7832	Siltstones/Shale	None Anticipated
Leadville	7832	8092	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 Goodman Point 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_2 Company, L.P.

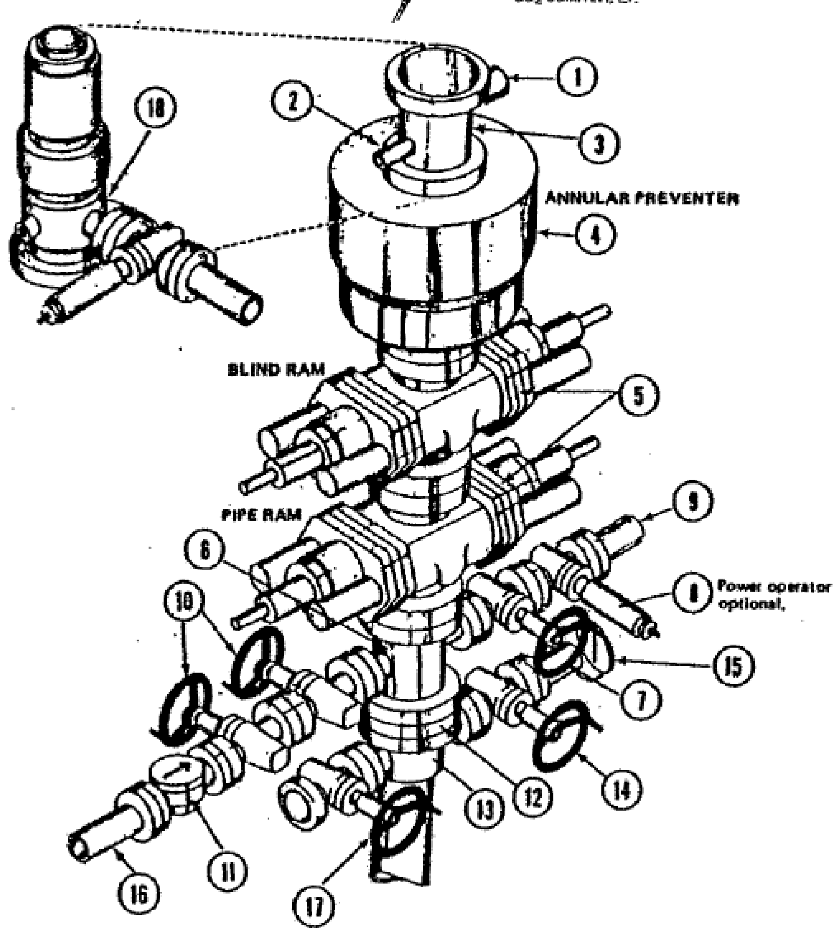
Doe Canyon and Goodman Point Wells

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 H2S 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 OCURS, 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*******

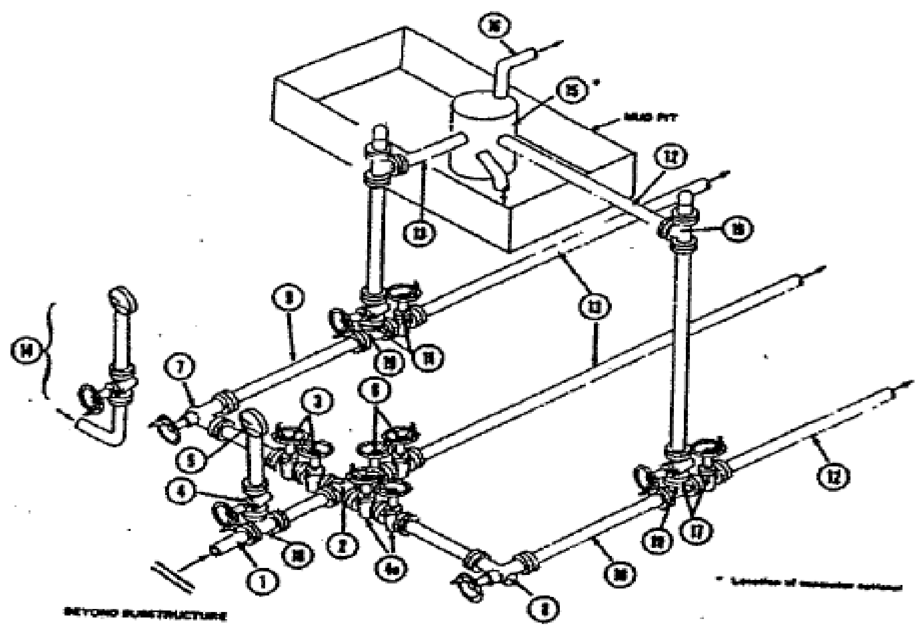
*******ALL TESTS MUST BE CHARTED FOR CO&G & BLM*******

KINDER MORGAN
CO2 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
CO2 COMPANY, L.P.



KINDER MORGAN MINIMUM CHOKE MANIFOLD REQUIREMENTS										
		Class 3M			Class 5M			Class 10M		
No.		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 Guage			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 guage, 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 pressuretest. 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.

[54 FR 39528, Sept. 27, 1989]

SECTION 4 – Drilling Equipment, Casing, and Cementing Programs

PROSPECT INFORMATION

The GP #15 will be one of multiple wells to be drilled during the 2006-2007 drilling program at McElmo Dome. 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 GP #15 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 26 days at a cost of $3,850,000.
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 GP #15 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 @ 5754':** 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 Baroid 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 2964', located approximately 100' below the top of the Cutler. A full string of 9-5/8" surface casing will be run to 2964' 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 7857’, located 25’ into the Leadville formation. The casing point will be picked by the mud-logger. 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 6.0” pilot hole will be drilled out from the 7” production casing to 200’ below the Leadville. 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.

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**
- <u>Drop a gyro survey at TD of the pilot hole section- used to build the final directional plan for lateral</u>
    - 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**		
SIZE	**INTERVAL**	**DESCRIPTION**	**COLLAPSE**	**BURST**	**TENSION**
9-5/8”	**0’ – 2964’**	**36# K-55 STC**	**2020 / 1.6**	**3520 / 1.8**	**423 / 4.9**
7”	**0’ – 5815’**	**29# CR13 FOX**	**7020 / 2.3**	**8160 / 2.9**	**676 / 7.3 (100’ above top of Paradox Salt)**
7”	**5815’ – 7444’**	**32# CR13 FOX**	**8600 / 1.2**	**9060 / 3.1**	**692 / 10 (run to 100’ below Paradox Salt)**
7”	**7444’ – 7857’**	**29# CR13 FOX**	**7020 / 1.8**	**8160 / 2.4**	**676 / 10 (from 100’ below Paradox 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:	880 sks => Light Standard => 5 lbm/sk Gilsonite (LC) + 0.125 lbm/sk Poly E Flake (LC)
Specifications:	12.4 ppg / 1.96 ft3 / sk / 10.33 gal / sk
100% Excess	
Tail CMT Slurry:	290 sks => Standard Cement => 94 lbm/sk Standard Cement + 0.125 lbm/sk Polyflake (LC)
Specifications:	15.6 ppg / 1.18 ft3 / sk / 5.23 gal / sk
100% Excess	
Displacement:	~259 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 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: Specifications: 50% Excess	610 sks => 50/50 Poz Standard (0.2% Versaset + 0.1% FDP-D766-05 + 2% Zoneseal 4000 13.0 ppg / 1.38 ft3 / sk / 6.39 gal / sk
Tail Slurry: Specifications: 50% Excess	300 sks => Premium Cement 94 lbm/sk + 0.1% HR-5 15.6 ppg / 1.18 ft3 / sk / 5.22 gal / sk
Cement Cap Slurry: Specifications:	100 sks => Standard Cement 94lbm/sk + 2% $CaCO_3$ + 5% Cal-Seal 15.0 ppg / 1.37 ft3 / sk / 6.32 gal / sk
Displacement:	~289 bbls freshwater @ 8 - 10 bbls / min
Volume Based:	Use 13” 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 - 2964' (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.

2964' - 5654' (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.

5654' – 7781' (25' into the Leadville / 7" Casing Point) and Pilot Hole (7781' – 8032'):

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.

7862' – 9862' Lateral (Lateral Length 2000'):

Hole Size: 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. Drill blind with freshwater at normal pump rates. 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 2 person crew is required for 24 hour coverage.

A measure while drilling (MWD) tool with gamma ray (GR) capability will be run from 7600' 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 – data 9' from bottom
- 2nd run density – data 4' from bottom
- 3rd run neutron and GR, data 3' and 13' from bottom

SECTION 7 – Expected Pressures and Identified Hazards

BOTTOM HOLE PRESSURE

The Leadville formation bottom hole pressure is 2,000 psi in the Goodman Point area, and 2,400 psi in the Doe Canyon area. Given the well depths of approximately 8000’, a fresh water column provides approximately 3,500 psi for well control.

H2S POTENTIAL

H2S is expected to be circulated to the surface during the drilling of the Killer Shales located within the Paradox Salt interval located at 6436’ - 7344’. 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 3,500 psi downhole pressure, and the reservoir pressure is 2,000 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 4,800 to 5,600 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 fallback.

A nitrogen managed pressure/underbalanced 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 and regain circulation in a managed pressure scenario. Managed pressure/underbalanced drilling equipment will be used to handle the return flow of nitrogen and any influx of CO_2 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.

In the event that the managed pressure/underbalanced 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'.

The reason for attempting to extend the lateral length (past the point where circulation is lost) is to decrease well decline, improve success rate, and improve well productivity, which will ultimately decrease the number of infill wells in the future.

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 Tops of Important Geologic Markers and Formations
2. 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. 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. Any supplementary information more completely describing the drilling equipment and casing program.
5. Type and characteristics of the proposed circulating medium 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. The anticipated type and amount of testing, logging and coring.
7. 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. Any other facets of the proposed operation which the lessee or operator wishes to point out for BLM's consideration of the application.

Two attachments are referenced in sections of the document.

1. H2S Contingency Plan
2. Directional Well Plan.

CONTACT INFORMATION	OFFICE	CELL	HOME
Operations Manager - Todd Gentles	713-369-8487	713-249-2805	713-249-2805
Drilling Director - Doug Frederick	713-369-9208	281-421-2333	
Geologist - Jerry Greer	71-369-8995	832-515-4325	281-353-3704

APPROVAL

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