

**Well Name:** Doe Canyon #16

**Well Configuration Type:** Directional

**Account Category/Property ID:**

**Surface Location:** 331' FNL & 2302' FEL, SEC 18, T.40 N, R. 17 W., NMPM

**County:** Dolores

**State:** Colorado

**Lat/Long Datum:** NAD 83

**Latitude (°):** 31.73363

**Longitude (°):** -108.76499

**Field Name:** DOE CANYON

**API/UWI:**

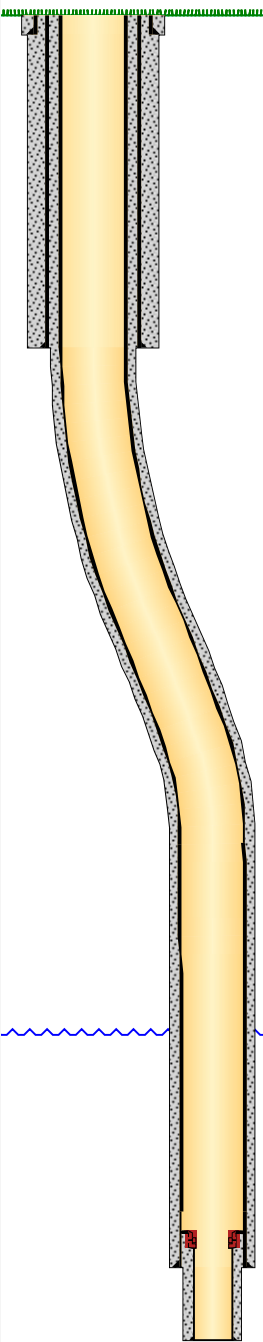
**Objective:**

**Bottom Hole Location:** 106' FNL & 3261' FEL, SEC 18, T.40 N., R. 17 W., NMPM

**Estimated KB Elevation (ft):** 7,405.20

**Ground Elevation (ft):** 7,405.20

**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 PARADOX SALT SHALES**

Directional - Proposed Original Hole, 12/17/2018 1:50:00 PM			DRILLING PROCEDURE: (add KB to measurements below)
Formations	TVD (ftKB)	MD (ftKB)	Directional schematic
Dakota Morrison	500	500	
Entrada	1,000	1,000	
Chinle	1,500	1,500	
Cutler	2,000	2,000	
	2,500	2,500	
	2,996	3,000	
	3,466	3,500	
	3,927	4,000	
Upper Hermosa	4,388	4,500	
	4,849	5,000	
Paradox Upper Ismay	5,327	5,500	<p><b>Objective</b> 16" conductor pipe will be set at ~80' before moving in the rig. A 14-3/4" hole drilled from surface to 2464' TVD/MD, ~100' below the top of the Cutler, set 10-3/4" casing run to 2464' TVD/MD with cement to surface. A 9-1/2" hole drilled out from surface casing point to 7-5/8" casing point at 8725' TVD/MD. Run 7-5/8" carbon steel casing set with last 200' comprised of 13-Chrome. A 6-1/2" production hole will be drilled out from the 7-5/8" casing point to ~400' below the Leadville Top. The production hole will be logged from TD to ~500' inside 7-5/8" casing shoe. A 4-1/2" 13-Chrome liner will then be run and cemented in place.</p> <p><b>CASING/CEMENTING DETAILS:</b> Comment 10 3/4" 40.5# J-55 STC =&gt; 0'-2464' TVD/MD Cement: Conventional =&gt; Lead 1250sx VersaCem + Tail 300sx LifeCem + Displacement ~200bbls Fresh Water Comment 7-5/8" 29.7# L-80 LTC =&gt; 0' - 5737 TVD/0' - 5913' MD (100' above top of Paradox Salt) Cement: Lead 2200sx HalCem + Tail 300sx HalCem + Cement Cap 100sx Premium Cement Comment 7-5/8" 33.7# L-80 LTC =&gt; 5737' - 8463' TVD/5913' - 8639' MD (run to 100' below Base Salt) Rytwrap Comment 7-5/8" 29.7# CR13 BEAR =&gt; 8463' - 8591' TVD/8639' - 8767' MD Comment 4-1/2" 12.6# CR13 VamTop =&gt; 8516' - 8970' TVD/8692' - 9146' MD Cement: Conventional =&gt; Lead 100sx HalCem + Displacement ~60bbls Fresh Water</p> <p><b>DRILLING FLUIDS:</b> Description 14-3/4" Surface Comment Spud 14-3/4" surface hole with spud mud and circulate. Use paper for seepage and LCM sweeps for lost circulation problems. Pump viscous sweeps if tight connections are encountered and prior to running casing. Description 9-1/2" (100' TVD above Desert Creek) Comment Drill out of the 10-3/4" casing with clean spud mud and circulate. Sweep for hole cleaning or lost circulation problems and use paper for seepage. Description 9-1/2" (25' TVD into the Leadville/7-5/8" Csg Pt) Comment Displace the spud mud system with salt saturated brine 100' above the Desert Creek formation. Pre-treat mud for H2S prior to drilling the P4 Shale. Description 6-1/2" Production Hole Comment During the production hole drill, fresh water will be treated so that the Cl2 content is ~20,000ppm. Acid soluble LCM will be added to mitigate lost circulation.</p> <p><b>SURVEY INFORMATION:</b> Comment 500' intervals from spud to the 10-3/4" casing point ~1000' intervals from below the 10-3/4" casing point to the top of the Paradox Salt Do not drop surveys while drilling below the Paradox Salt due to potential sticking ~500' intervals from below the Paradox Salt Shales to TD</p> <p><b>EVALUATION PROGRAM:</b> Evaluation Program 6-1/2" Pilot Hole: 1st run gamma ray, neutron, density, monopole sonic 2nd run dual laterolog Cased Hole: 1st run GR, pulse neutron from 7-5/8" shoe to surface casing shoe 2nd run CBL over 7-5/8" casing 3rd run CBL over 4-12" liner</p>
	5,825	6,000	
Gothic Shale	6,325	6,500	
Desert Creek	6,825	7,000	
Paradox Salt	7,325	7,500	
	7,825	8,000	
	8,325	8,500	
Base of Paradox Salt	8,825	9,000	
Pinkerton Trail (L Hermosa)	9,325	9,500	
Leadville I/C			
Leadville (Base of Karst)			
Ouray			
			Not to Scale

**Expected Bottom Hole Pressure = 2000 psi (2500 psi max if compartmentalized)**

- Objectives:**
1. Maintain a focused effort by everyone on location to eliminate all accidents.
  2. Drill, evaluate, case and complete the well at or under AFE cost estimate.
  3. Run the 7-5/8" production casing to ~25' TVD below the top of the Leadville formation.
  4. Isolate the 7-5/8" to surface with high quality cement.
  5. Run the 4-1/2" 13-Chrome liner through the Leadville formation.
  6. Isolate the 4-1/2" 13-Chrome liner with high quality cement.

## **WELL PROGNOSIS OVERVIEW**

This well prognosis is organized to follow the Bureau of Land Management (BLM) Nine-Point Drilling Plan referenced in “Onshore Oil and Gas Order Number 1, Approval of Operations.” The Nine Points correspond to the following sections of this Prognosis:

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

1. Names and estimated tops of all geologic groups, formations, members, or zones.
2. Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or prospectively valuable deposits of other minerals that the operator expects to encounter, and the operator’s plans for protecting such resources.

### **SECTION 3 – Pressure Control Equipment**

3. The operator’s minimum specifications for blowout prevention equipment and diverter systems to be used, including size, pressure rating, configuration, and the testing procedure and frequency. Blowout prevention equipment must meet the minimum standards outlined in Order 2.

### **SECTION 4 & 5 – Drilling Equipment, Casing, and Cementing Programs**

4. The operator’s proposed casing program, including size, grade, weight, type of thread and coupling, the setting depth of each string, and its condition. The operator must include the minimum design criteria, including casing loading assumptions and corresponding safety factors for burst, collapse, and tensions (body yield and joint strength). The operator must also include the lengths and setting depth of each casing when a tapered casing string is proposed. The hole size for each well bore section of hole drilled must be included. Special casing designs such as the use of coiled tubing or expandable casing may necessitate additional information.
5. The estimated amount and type(s) of cement expected to be used in the setting of each casing string. If stage cementing will be used, provide the setting depth of the stage tool(s) and amount and type of cement, including additives, to be used for each stage. Provide the yield of each cement slurry and the expected top of cement, with excess, for each cemented string or stage.

### **SECTION 6 – Mud Program**

6. Type and characteristics of the proposed circulating medium or mediums proposed for the drilling of each well bore section, the quantities and types of mud and weighting material to be maintained, and the monitoring equipment to be used on the circulating system. The operator must submit the following information when air or gas drilling is proposed:
  - Length, size, and location of the bloop line, including the gas ignition and dust suppression systems;
  - Location and capacity of the compressor equipment, including safety devices, describe the distance from the well bore, and location within the drill site; and
  - Anticipated amounts, types, and other characteristics as defined in this section, of the stand by mud or kill fluid and associated circulating equipment.

### **SECTION 7 – Evaluation Program**

7. The testing, logging, and coring procedures proposed, including drill stem testing procedures, equipment, and safety measures.

### **SECTION 8 – Expected Pressures and Identified Hazards**

8. The expected bottom-hole pressure and any anticipated abnormal pressures, temperatures, or potential hazards that the operator expects to encounter, such as lost circulation and hydrogen sulfide (see Order 6 for information on hydrogen sulfide operations). A description of the operator’s plans for mitigating such hazards must be included.

### **SECTION 9 – Other Items**

9. Any other facets of the proposed operation that the operator would like the BLM to consider in reviewing the application. Examples include, but are not limited to:
  - For directional wells, proposed directional design, plan view, and vertical section in true vertical and measured depths;
  - Horizontal drilling; and
  - Coil tubing operations.

Other attachments are referenced in sections of the document

1. Paradox Salt Drilling Procedure (Appendix A)
2. H<sub>2</sub>S Contingency Plan

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

<b>Formation</b>	<b>Top (TVD, ft)</b>	<b>Top (MD, ft)</b>	<b>Composition</b>	<b>Anticipated Fluids</b>
Dakota	Surface	Surface	Sandstone/Shale	Fresh Water
Morrison	112	112	Sandstone/Shale - Unconsolidated	Fresh Water
Entrada	1020	1020	Sandstone - Unconsolidated	Fresh Water
Chinle	1647	1647	Sandstone - Unconsolidated	Fresh Water
Cutler	2364	2364	Sandstone/Shale	None Anticipated
Honaker Trail (Upper Hermosa)	4159	4251	Limestone/Shale	None Anticipated
Paradox	5117	5284	Limestone/Shale/Anhydrite	None Anticipated
Upper Ismay	5246	5417	Limestone/Shale	HC Gas
Gothic Shale	5565	5740	Shale	HC Gas
Desert Creek	5718	5894	Limestone/Shale	HC Gas
Paradox Salt	5837	6013	Halite/Anhydrite/Shale Stringers	H2S/HC Gas
Base of Paradox Salt	8315	8491	Shale/Salt Stringers/Limestone Stringers	None Anticipated
Pinkerton Trail (Lower Hermosa)	8363	8539	Limestone/Siltstone/Shale	CO2/HC Gas/Water
Molas	8466	8642	Red Siltstone	None Anticipated
Leadville U/C (Seismic Horizon)	8566	8742	Limestone/Shale	CO2
Leadville (Base of Karst)	8612	8788	Dolomite/Limestone/Shale	CO2/Water
Ouray	8869	9045	Dolomite/Shale	None Anticipated
<b>Drilling TD</b>	<b>8970</b>	<b>9146</b>		

- **10-3/4" Surface Casing:**
  - Set ~100' TVD into the Cutler formation, and
  - Cemented to surface to isolate the usable fresh water bearing sandstone formations above.
- **7-5/8" Intermediate Casing:**
  - Set ~25' TVD into the Leadville U/C (Unconformity) formation, and
  - Cemented to surface to isolate the paradox salt section, which may contain hydrogen sulfide gas, and all zones above.
- **4-1/2" Production Liner**
  - Set ~400' TVD into the Leadville producing formation, and
  - Cemented in place for completion purposes.

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 8 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 & Testing Procedure for 10-3/4"**

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

**Doe Canyon and McElmo Dome Wells**

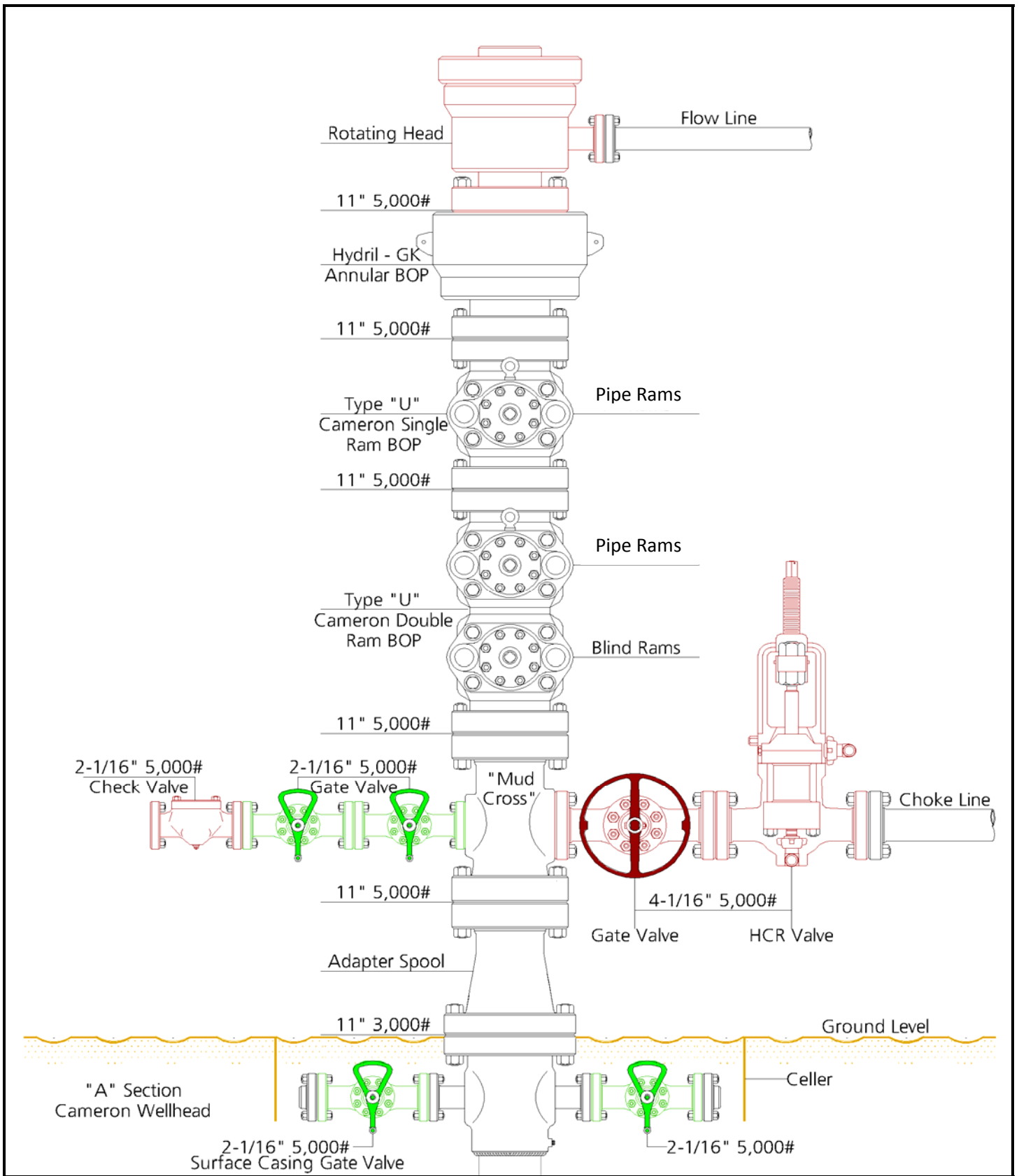
**A 16-3/4" 3M annular preventer with a diverter will be used on the surface hole.**

1. NIPPLE UP ON 10-3/4" X 11" 3000# SCREW ON WELLHEAD
  - a. INSTALL 11" X 11" 3000# SPOOL W/ TWO SIDE OUTLETS (4" & 2")
  - b. INSTALL 11" 3000# SINGLE HYDRAULIC BOP (NO RAM BLOCK INSTALLED)
  - c. INSTALL 11" X 11" 3000# SPACER SPOOL (8" - 10" LONG)
  - d. INSTALL 11" 3000# DOUBLE RAM BOP (BLIND ON BOTTOM, PIPE ON TOP)
  - e. INSTALL 11" 3000# HYDRIL ANNULAR BOP
  - f. INSTALL 11" 3000# ROTATING HEAD
  - g. NIPPLE UP FLOW LINES TO ROTATING HEAD
  - h. INSTALL 4" 3000# MANUAL VALVE ON SIDE OF SPOOL
  - i. INSTALL 4" 3000# HCR VALVE ON SIDE OF MANUAL VALVE
  - j. NIPPLE UP HCR VALVE TO 3000# CHOKE MANIFOLD (IF H2S EXPECTED, INSTALL HYDRAULIC SUPER CHOKE)
2. FUNCTION TEST BLIND RAMS, PIPE RAMS, AND HCR VALVE
  - a. USE CLEAR WATER TO TEST
  - b. MAKE SURE ALL BOP's ARE HOOKED UP TO ACCUMULATOR
  - c. MAKE SURE ALL RAMS, HYDRIL AND HCR VALVE FUNCTION PROPERLY
3. TEST BOPE WITH CASING AND NO PLUG
  - a. CLOSE BLIND RAMS WITH NO PLUG
  - b. TEST 10-3/4" CSG & BLIND RAMS TO 300# FOR 30 MIN. & 1000# FOR 30 MIN.
  - c. A DECLINE OF MORE THAN 10% IN 30 MIN. SHALL BE CONSIDERED FAILED
4. TEST BOPE WITH CASING AND WITH PLUG
  - a. INSTALL TEST PLUG IN 10-3/4" X 11" 3000# WELL HEAD WITH ALL VALVES OPEN BELOW TEST PLUG
  - b. MAKE SURE BOP's ARE FULL OF WATER AND VALVES SHALL BE TESTED FROM WORKING PRESSURE SIDE DURING BOP TEST
  - c. CLOSE PIPE RAMS AND TEST 300# FOR 10 MIN. & 1000# FOR 10 MIN. WITH NO LOSS IN PRESSURE
5. TEST BOPE WITH NO CASING AND WITH PLUG
  - a. REMOVE DRILL PIPE WITH TEST PLUG IN PLACE
  - b. CLOSE BLIND RAMS
  - c. TEST BLIND RAMS, HCR VALVE, MANUAL VALVE & CHOKE MANIFOLD TO 300# FOR 10 MIN. & 3000# 10 MIN. WITH NO LOSS IN PRESSURE
6. TEST HYDRIL
  - a. OPEN BLIND RAMS, INSTALL DRILL PIPE
  - b. CLOSE HYDRIL
  - c. TEST HYDRIL TO 300# FOR 10 MIN. & 1500# FOR 10 MIN. WITH NO LOSS IN PRESSURE)

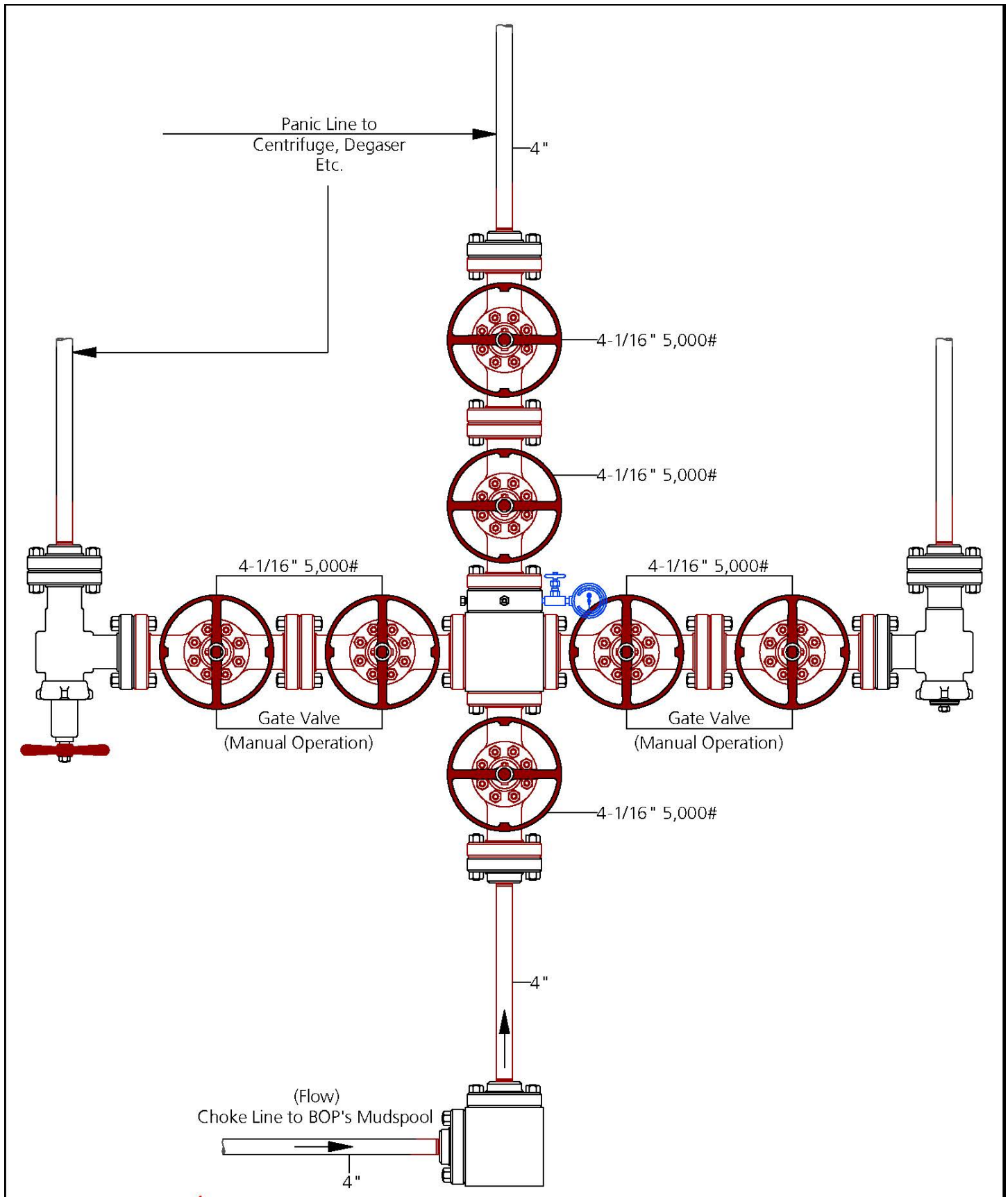
**\*\*\*EMAIL KM REGULATORY REP 24HOURS PRIOR TO BOPE TEST\*\*\***

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

## BOP CONFIGURATION



## CHOKE MANIFOLD



**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, bridge plug, 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 pre-charge. 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 pre-charge 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 pre-charge 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 pre-charge Pressure is found to be above or below the maximum or minimum limit specified below (only Nitrogen gas may be used to pre-charge):

<b>Accumulator working pressure rating</b>	<b>Minimum acceptable operating pressure</b>	<b>Desired pre-charge pressure</b>	<b>Maximum acceptable pre-charge pressure</b>	<b>Minimum acceptable pre-charge pressure</b>
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 pre-charge 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 & 5 – Drilling Equipment, Casing, and Cementing Programs

### PROSPECT INFORMATION

The Doe Canyon 16 (DC-16) will be drilled during the 2019 drilling program at Doe Canyon. The wellplan calls for a 10-3/4" x 7-5/8" casing x 4-1/2" 13-Chrome liner program.

### WELL OBJECTIVE

The main objectives for the drilling operation on the DC-22 are:

1. Maintain a focused effort by everyone on location to eliminate all accidents.
2. Drill, evaluate, case and complete the well at or under the AFE cost estimate.
3. Run the 7-5/8" intermediate casing to ~25' TVD into the Leadville formation.
4. Isolate the 7-5/8" to surface with high quality cement.
5. Run the 4-1/2" 13-Chrome liner through the Leadville formation.
6. Isolate the 4-1/2" 13-Chrome liner with high quality cement.

### POTENTIAL PROBLEMS

The main problems for the DC-16 are the typical problems expected while drilling in the area:

1. **Lost Circulation in the Surface Hole:** Lost circulation can be expected at any depth while drilling the surface hole. Maintain a clean fresh water system, utilizing the closed loop system 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 Formation:** 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 H<sub>2</sub>S from the Paradox Salt Shales:** Geo-pressured shales from the P4 on down will contain varying amounts of gas and associated H<sub>2</sub>S. Circulate the salt water of the closed loop system to remove excess gas. Pre-treat the mud using H<sub>2</sub>S scavenger for H<sub>2</sub>S contamination.
4. **Stuck Pipe in the Paradox Salt Shales:** The Paradox Salt Shale is a high pressure, low volume shale which "flows" into the well causing stuck pipe. An attached list of recommendations for drilling the Paradox Salt Shale, titled "Paradox Salt Drilling Procedure", is located in Appendix A of this prognosis. 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 Paradox Salt shale and discuss in detail the procedure for drilling the shale.
5. **Gas Kick from Leadville after Production Casing set:** Gas kicks have been encountered during the drilling/well stimulation within the open hole segment of the Leadville. The primary barrier is the BOPE and the hydrostatic pressure of the kill fluid (fresh water). Drill pipe/workstrings will be utilized with double float valves inserted. This will prevent kicks from occurring up the drill pipe/workstring during drilling or stimulation in the Leadville.

## GENERAL DRILLING PROCEDURE

16" conductor pipe will be set at ~80' prior to moving in the drilling rig. It is necessary to rig up a 16-3/4" 3M annular preventer with diverter to drill the surface hole.

A 14-3/4" hole will be drilled from surface to 2464' TVD/MD, located ~100' TVD below the top of the Cutler. A full string of 10-3/4" surface casing will be run to 2464' TVD/MD with cement circulated to surface. The 10-3/4" surface casing will protect the groundwater in the area. After the casing is run and cemented, screw on the 10-3/4" 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.

A 9-1/2" hole will be drilled out from the surface casing point to the 7-5/8" casing point at 8591' TVD/8767' MD, located ~25' TVD into the Leadville formation. At approximately 8400' TVD/8576' MD a measurement while drilling (MWD) gamma ray (GR) system will be picked up. This, along with mud logging, will be used to pick the 7-5/8" casing point. A string of 7-5/8" carbon steel casing with the last 200' comprised of 13-Chrome casing will be run and set ~25' TVD into the Leadville. The well integrity is dependent on the 13-Chrome casing being handled and run correctly. The 7-5/8" 13-Chrome requires special handling and is to be handled according to the procedures specified on site. The 7-5/8" casing will be cemented back to surface in one stage. A CBL log will be run.

A 6-1/2" production hole will be drilled out from the 7-5/8" casing to ~400' TVD below the Leadville top. A gyro will be dropped at TD of the production hole on the trip out of the hole. The production hole will then be logged from TD to ~500' inside the 7-5/8" casing shoe. After logging and analysis of the logs indicates a productive interval, a 4-1/2" 13-Chrome liner will be run and cemented in place. The liner will then be perforated, tested for CO<sub>2</sub> production and/or acid stimulated.

This well will be drilled with a closed loop, pitless system.

## SURVEY DETAIL

Normal well deviation is not a concern.

### Inclination surveys:

- ~500' intervals from spud to the 10-3/4" casing point and
- ~1000' intervals from below the 10-3/4" casing point to the top of the Paradox Salt
- **Do not drop surveys while drilling below the Paradox Salt due to potential sticking**
- ~500' intervals from below the Paradox Salt to TD

CASING DETAILS							
SIZE	INTERVAL L	INTERVAL	LENGTH	DESCRIPTION	COLLAPSE	BURST	TENSIO N
	(ft, TVD)	(ft, MD)	(ft)		(psi / SF)	(psi / SF)	(klbs / SF)
<b>Surface Casing</b>							
<i>(Surface to TD ~100' TVD into the Cutler Formation)</i>							
10-3/4"	0' – 2464'	0' – 2464'	2464'	40.5# J-55 STC	1580 1.52	3130 2.3	629 2.26
<b>Intermediate Casing</b>							
<i>(Surface to 100' TVD above top of Paradox Salt)</i>							
7-5/8"	0' – 5737'	0' – 5913'	5913'	29.7# L-80 LTC	4790 2.66	6890 2.28	683 1.77
<i>*RytWrap* (100' TVD above top of Paradox Salt to 100' TVD below Base Salt)</i>							
7-5/8"	5737' – 8463'	5913' – 8639'	2726'	33.7# L-80 LTC	6560 2.66	7900 2.46	778 2.88
<i>(100' TVD below Base Salt to TD ~25' into the Leadville U/C formation)</i>							
7-5/8"	8463' – 8591'	8639' – 8767'	128'	29.7# CR13 BEAR	4918 1.94	7315 2.27	726 2.64
<b>Liner</b>							
<i>(Hanger set ~75' in 7-5/8" to TD)</i>							
4-	8516' –	8692' –	454'	12.6# CR13 Vam	4918	7315	726

1/2"	8970'	9146'		Top	1.94	2.27	2.64
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All of the 33.7# casing will be coated with Rytwrap (ICO in Odessa) prior to arriving on location.

#### DESIGN ASSUMPTIONS:

10-3/4" 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 = 1.32
7-5/8" Intermediate	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
4-1/2" Liner	Tension:	Buoyed weight in 8.4 ppg fresh water
	Collapse:	Full evacuation in 9.0 ppg on outside
	Burst:	3000 psi shut in pressure at the surface

## CEMENTING PROCEDURE

### 10-3/4" SURFACE CASING → Single stage

Use API 9-1/2" drift on location

Shoe Type:	Regular Guide Shoe
Collar Type:	Regular Float collar, 40' above shoe
Centralizers:	15 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 294,000 lbs based on 40.5# J-55 STC w/ a 1.6 SF
Preflush:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
<b>Lead CMT Slurry:</b>	1250 sks → VersaCem™ System → 5 lb/sk KOL-SEAL + 0.125 lb/sk POLY-E-FLAKE + 0.1% Halad®-9
Specifications:	12.4 ppg / 1.92 ft <sup>3</sup> / sk / 9.91 gal / sk
<b>100% Excess</b>	
<b>Tail CMT Slurry:</b>	300 sks → LifeCem™ System → 0.125 lb/sk POLY-E-Flake + 0.1% Halad-9
Specifications:	15.6 ppg / 1.15 ft <sup>3</sup> / sk / 5.06 gal / sk
<b>100% Excess</b>	
<b>Displacement:</b>	~200 bbls → Fresh Water @ 8 - 10 bbls / min
Volume Based:	All volumes listed are estimates only, for calculations use 14-3/4" 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# J-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:	<ol style="list-style-type: none"><li>1. Report the volume of cement circulated to the surface.</li><li>2. WOC for a minimum of 12 hours prior to drilling out.</li><li>3. NU 3M - 11 - BOP and test to rating.</li><li>4. Test the casing to 500 psi.</li><li>5. Cement Co. → Send copy of pressure charts, job log and summary to: Kinder Morgan, Attn: Todd Gentles, 1001 Louisiana St, Suite 1000, Houston, TX 77002</li></ol>

## CEMENTING PROCEDURE

### 7-5/8" INTERMEDIATE CASING → Single stage

Shoe Type:	Differential Fill Float Shoe
Collar Type:	Differential Fill Float Collar, 40' above shoe
Centralizers:	80 required => 10' above shoe and every other joint excluding wrapped casing
Flag Joints:	Cross over from 32# to 29# 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:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
Lead Slurry:	2200 sks → HalCem™ System → 0.2% Versaset + 0.2% Halad-766
Specifications:	13.0 ppg / 1.43 ft <sup>3</sup> / sk / 6.61 gal / sk
100% Excess	
Tail Slurry:	300 sks → HalCem™ System → 0.2% Halad-766 + 0.2% Versaset
Specifications:	13.5 ppg / 1.3 ft <sup>3</sup> / sk / 5.77 gal / sk
50% Excess	
Cement Cap Slurry:	100 sks → Premium Cement → 2% CaCl <sub>2</sub>
Specifications:	15.8 ppg / 1.17 ft <sup>3</sup> / sk / 5.13 gal / sk
Displacement:	~300 bbls freshwater @ 8 - 10 bbls / min
Volume Based:	Use 9.5" 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
CBL Survey:	A CBL will be run after setting and cementing of this casing.
Wellhead:	Install section "B" assembly
Special Note:	<ol style="list-style-type: none"><li>1. Circulate 3 annular volumes prior to cementing @ maximum rate possible.</li><li>2. Displace cement at the maximum rate possible.</li><li>3. Report volumes of cement circulated.</li><li>4. Report any circulation problems on the morning report.</li><li>5. Cement Co. → Send copy of pressure charts, job log and summary to: Kinder Morgan, Attn: Todd Gentles 1001 Louisiana St., Suite 1000, Houston, TX 77002</li></ol>

## CEMENTING PROCEDURE

### 4-1/2" PRODUCTION LINER → Single stage

Shoe Type:	Differential Fill Float Shoe
Collar Type:	None
Centralizers:	None
Flag Joints:	None
Other Equipment:	Thread lock the bottom 3 joints of casing + all float equipment.
Reciprocate:	If required, limit @ 50,000 lbs
Preflush:	10 bbls → Fresh water 20 bbls → Chemical wash 10 bbls → Fresh water
Lead Slurry:	100 sks → HalCem™ System → 0.2% Halad®-9 + 0.1% HR-5 + 5lbm Kol-Seal + 0.1% CFR-3 W/O
Specifications:	13.0 ppg / 1.43 ft3 / sk / 6.76 gal / sk
50% Excess	
Displacement:	~60 bbls freshwater @ 8 - 10 bbls / min
Volume Based:	Use 6.5" 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:	None
CBL Survey:	A CBL will be run after setting and cementing of this casing.
Wellhead:	None
Special Note:	1. Displace cement at the maximum rate possible. 2. Report any circulation problems on the morning report. 3. Cement Co. → Send copy of pressure charts, job log and summary to: Kinder Morgan, Attn: Todd Gentles 1001 Louisiana St., Suite 1000, Houston, TX 77002

## **SECTION 6 – Mud Program**

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

### **Surface - 2464’ TVD | Surface – 2464’ MD (10-3/4” Casing Point):**

Hole Size: 14-3/4”  
Mud Type: Spud mud  
Mud Weight: 8.5 – 9.0 ppg  
pH: 9.5  
Salt Conc: 1,200 ppm

Spud the surface hole with spud mud and circulate the closed loop system. 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 casing.

### **2464’ - 5618’ TVD | 2464’ - 5794’ MD (100’ TVD above the Desert Creek):**

Hole Size: 9-1/2”  
Mud Type: Spud mud  
Mud Weight: 8.5 – 9.0 ppg  
pH: 9.5  
Salt Conc: 1,200 ppm  
Problems: Seepage, hole cleaning

Drill out of the surface casing with clean spud mud. Circulate the closed loop system 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.

### **5618’ – 8591’ TVD | 5794’ – 8767’ MD (25’ TVD into the Leadville , 7-5/8” Casing Point):**

Hole Size: 9-1/2”  
Mud Type: Salt saturated brine  
Mud Weight: 10+ ppg  
pH: 11+, as required to control H2S  
Salt Conc: 190,000 ppm (as saturated as possible)  
Problems: H2S, Paradox Salt Shale gas influx, hole cleaning

Displace the fresh water system with salt saturated brine 100’ above the Desert Creek formation. Circulate through the closed loop system 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 Paradox Salt Shale, titled “Paradox Salt Drilling Procedure”, which is located in Appendix A of this prognosis. The recommendations have proven to be very successful in recent drilling programs.

### **8591’ – 8970’ TVD | 8767’ – 9146’ MD (Production Hole):**

Hole Size: 6-1/2”  
Mud Type: Fresh water  
Mud Weight: 8.4 ppg  
pH: 9-9.5 with caustic soda  
Salt Conc: 20,000 ppm  
Problems: LC, Hole cleaning, Lubricity

During the production hole drill the fresh water will be treated so that the Cl<sub>2</sub> content is ~20,000ppm. A pill containing ~30,000 ppm CL<sub>2</sub> will be placed over the open hole interval after TD. This is for logging purposes. Acid soluble LCM will be added to mitigate lost circulation. If circulation is lost and unable to be regained, nitrogen (or air) 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 7 – Evaluation Program**

Mud logging services will be used from surface to TD. Samples will be taken in 10' intervals.

A measure while drilling (MWD) tool with gamma ray (GR) capability will be run from 8400' TVD | 8576' MD 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 6-1/2" production hole will be logged with 2 runs as follows:

- 1<sup>st</sup> run: gamma ray, neutron, density, monopole sonic
- 2<sup>nd</sup> run: dual laterolog

The wellbore will be logged to the surface casing shoe through casing with 3 runs as follows (COGCC Rule 317.p)

- 1<sup>st</sup> run GR, pulsed neutron from 7-5/8" casing shoe to surface casing shoe
- 2<sup>nd</sup> run CBL over 7-5/8" casing
- 3<sup>rd</sup> run CBL over 4-1/2" liner

## **SECTION 8 – Expected Pressures and Identified Hazards**

### **BOTTOM HOLE PRESSURE**

The Leadville formation is approximately 325' thick in the Doe Canyon and McElmo Dome area. This vertical hole will be drilled in the Leadville formation. The expected bottom-hole pressure is currently about 1900 psi in the Doe Canyon area. Original field pressures were in the range of 2500 psi; 2500 psi would be the maximum pressure expected should there to be compartmentalization within the reservoir. This reservoir is unpressured; given the well depths of approximately 9000' TVD, a fresh water column provides approximately 3900 psi for well control. During drilling/well stimulation operations, the drill pipe/workstring will have double float valves installed to prevent kicks from coming up the string.

### **H<sub>2</sub>S POTENTIAL**

H<sub>2</sub>S is expected to be circulated to the surface during the drilling of the Paradox Salt Shales. The H<sub>2</sub>S contingency plan that was used in the previous programs has been updated and revised and will be in force. This plan is located in Appendix A of this prognosis. All the necessary precautions, drills, and training will be done to protect personnel on location. H<sub>2</sub>S monitors and safety equipment will be on location and operational prior to drilling the section and remain until rig release.

## **SECTION 9 – Other Items**

### **LOST CIRCULATION CONTINGENCY PLAN**

Circulation may be lost in the 6-1/2" production hole. In this situation, managed pressure drilling techniques may be implemented. A normal fresh water fluid column of water is approximately 3900 psi downhole pressure, and the reservoir pressure is 2500 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 5280 to 6150 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 drilling package can be brought out to location while drilling the production hole 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.

## **GENERAL COMPLETION PROCEDURE**

The well will be completed by perforating the 4-1/2" liner in the Leadville formation. Log analysis will determine placement of the perforations and whether the perforations will be acidized. A static pressure test may be collected prior to the well being tested for CO<sub>2</sub> production. The well will then be shut in until production facilities are constructed.

<b>CONTACT INFORMATION</b>	<b>OFFICE</b>	<b>CELL</b>
Operations Manager – Todd Gentles	713-369-8487	713-249-2805
Drilling Director – Doug Frederick	713-369-9208	281-421-2333
Drilling Engineer – Michael Matson	713-420-5447	281-220-7385
Geologist – Kevin Schmidt	713-420-5549	817-217-8504

## **APPROVAL**

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

## Appendix A: Paradox Salt Drilling Procedure

Ten distinct shale bodies occur in the Paradox Salt formation. Most notably, shale numbers 4, 5 and 6, and their associated anhydrite, in the sequence of the Paradox Salt that has the potential for high H<sub>2</sub>S content and tendency to stick pipe. This section lies approximately 400'-500' into the Paradox and usually has a 20'-30' salt section between shale number 4 and 5. Because these shales are subject to plastic flow, to prevent sticking, the following procedure has worked in the past and is recommended.

### *Preparing to drill the Paradox Salt Formation*

1. Test the BOPs on the last bit trip prior to drilling the Paradox Salt.
2. Pick up a set of mechanical Daily Oil Tool drilling jars on the last bit trip prior to drilling into the Paradox.
3. Run a survey to the top of the salt. This will help to avoid shutting down while drilling the sticky shales.
4. Use the salt formation cross-section as an indicator for predicting where each of the shale bodies will be encountered. Shales number 4, 5 and 6 are considered to be the most troublesome.
5. Increase flow rate to an annular velocity of at least 200 ft/min. Limitations of the rig's hydraulic system should be considered when selecting bit nozzle sizes.

### *Drilling the Paradox Salt Formation*

6. The Driller will hand drill the interval beginning at the top of the Paradox Salt and continue until all problem shales have been penetrated and normal conditions return.
7. Control drill the Paradox while noting the normal torque values for the salts. If there is any fluctuation in pump pressure or torque, pick up off bottom and ream until hole conditions stabilize. Drill a maximum of 5' of salt and 1'-2' of shale before picking up 15'- 20' and reaming to bottom slowly to clean the wellbore. The severity of torque, and increases in pump pressure, should dictate the interval lengths. Some portions of the hole may require drilling only a few inches before picking up and reaming.
8. After 1' to 2' of shale is penetrated, expect 50,000-100,000 lbs drag to free the bit initially. After freeing the bit, pick up 15'-20' and start reaming back to bottom. If the torque increases 20-30 ft-lb above normal, pick up and expect 25,000-50,000 lb drag.
9. On each Kelly down, have the Driller pick up a full Kelly plus one single, then ream back to bottom. Reaming serves two purposes:
  - a. It conditions the walls of the wellbore
  - b. It allows for the cuttings to be carried away from the bit and collars before making a connection.
10. Pipe should be pulled and run slowly to avoid problems in the tight sections of the hole. Torque should dictate the frequency of the short trips. Periodic short trips through the entire salt section have proven useful in reducing high torque due to sticky shale.

At the present time, the key to drilling these sticky shales in the Paradox Salt is **PATIENCE**. It should be noted that good gas shows are also present in these shale stringers, and as the gas out of the sticky shales starts to subside, the hole starts to stabilize.