DRILLING PLAN (CONFIDENTIAL)

Banta Ridge Federal 11-18-1-103

Lot 4, Sect. 18, T1S, R103W Rio Blanco County, CO

BLM Lease # COC-56873

Foundation Energy Management, LLC (Operator) presents the following Drilling Plan for the Federal 11-18-1-103 well with a surface location of 1383' FNL and 954' FWL in the SWNW (Lot 2) Section 18, TIS, RI03W. This well will be located on BLM managed lands and is authorized under lease COC-56873. The proposed well will be drilled directionally to a bottom hole location of 2070' FNL and 1816' FWL in the SENW Section 18, T1S, R103W to a MD TD of 4714' and a TVD of 4500'.

In accordance with the requirements of Onshore Oil and Gas Order Number 2 (43 CFR 3162.3), the following detailed drilling plan is provided.

Geologic Prognosis

Estimated Formation Tops	Graded GL: 6054'	KB elevation: 6069'
	MD (ft)	TVD (ft)
Mesa Verde	310	310
Sego	2817	2716
Castlegate	3195	3021
Mancos B	4389	4186
Mancos Shale	4540	4336
TD	4703	4500

Estimated Depths and Names of Anticipated Oil, Gas and Water Bearing Formations

Substance	Formation	Depth
Water	Castlegate	3211' MD
Oil and/or gas	Mancos B	4391' MD

All shows of fresh water will be reported and protected behind cemented casing.

Well Control Equipment

1. Operator's minimum specifications for pressure control are as follows:

Depth Range	Well Control Equipment
0-300' (surface interval)	No Control
300'-TD	11", 3000 psi double ram preventer with one set of blind and one set of pipe rams, as per the attached Figure 1.
No abnormal temperatures or H2S gas are anticipated. No over-pressure intervals are expected	

2. Operator will comply with all requirements pertaining to well control as listed in Onshore Oil and Gas Order No. 2 as well as Colorado Oil and Gas Conservation Commission (COGCC) Rules and Regulations.

3. Operator will comply with Onshore Oil and Gas Order No. 2 as well as COGCC regulations concerning the installation and testing of blow out prevention (BOP) equipment for a **2M system** to include the following:

   a. Ram type preventers and associated equipment shall be tested to approved stack working pressure if isolated by test plug or to 70% 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% 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.

   b. All BOP tests will be performed by a tester and not by the rig pumps using clear water or an appropriate clear liquid for subfreezing temperatures. Pressure shall be maintained at least 10 minutes or until provisions of test are met, whichever is longer.

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

      i. When initially installed;

      ii. Whenever any seal subject to test pressure is broken;

      iii. Following related repairs;

      iv. At 30-day intervals; and

      v. Valves shall be tested from working pressure side during BOP tests with all downstream valves open.

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

   e. Annular preventers shall be functionally operated at least weekly, if installed.

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

   g. A BOPE pit level drill shall be conducted weekly for each drilling crew, while mud drilling.

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

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

   j. See Figure 1 for a typical BOP diagram.

Casing Program

Hole Size (in)	Casing / Tubing Size (in)	Wt. (#/ft)	Grade	Connection	Length (ft)	Setting Depth(ft)
12-1/4”	8-5/8”	24	J-55	STC	300	300
7-7/8”	4-1/2”	11.6	N-80	LTC	4600	4600

	Tension	Burst	Collapse	SF tension	SF burst	SF collapse
8-5/8” 24# J-55 STC	263,000 lbs	2,950 psi	1,370 psi	36.5	14.03	10.38
	Tension	**Burst**	**Collapse**	**SF tension**	**SF burst**	**SF collapse**
4-1/2” 11.6# N-80 LTC	223,000 lbs	7,780 psi	6,350 psi	4.08	3.57	2.92
4-1/2” 11.6# J55 LTC	162,000 lbs	5,350 psi	4,960 psi	2.96	2.46	2.28

The 8 5/8” surface casing string will be centralized using bow spring centralizers. The bottom (3) joints of casing will be centralized. From that point up, one centralizer will be run on every other joint to surface.

The 4½” production casing will be centralized using bow spring centralizers. Every other joint from the shoe to 3200’ and every third joint from 3200’ to the top of cement will be centralized with bow spring centralizers.

The above safety factors assume a maximum formation pressure gradient of 0.44 psi/ft and a fracture gradient of 0.70 psi/ft, per Onshore Order #2 Section III.B. Expected formation pressure gradient is expected to be approximately 0.35 psi/ft.

All pipe will be new or electronically inspected to minimum 87.5% wall thickness.

Cementing Program

8 5/8” Surface Casing:

Cement with approximately 100 sx of Halliburton Versacem with a yield of 2.34 ft3/sk and a mix wt of 12.3 lbs/gal. Volumes include approximately 75% excess to help assure circulating cement to surface. If the primary cement job does not circulate to surface, sufficient top jobs will be performed to bring cement to surface. WOC until cement reaches 500 psi compressive strength minimum prior to drilling out.

4 ½” Production Casing:

Cement with approximately 970 sx of Halliburton Halcem System with .25 #’s/sk Poly E Flake, 13.5 ppg, 1.41 yield. Volumes to include 10% excess over caliper. Design cement top is at surface. A bond log will be run to verify cement top if cement does not surface.

Mud Program

Interval	Mud Description	Weight	Viscosity	Wtr Loss
Surface to 300’	Spud Mud	8.5-8.9	35-40	NC
300’ to TD	3% KCl Polymer	8.6-9.3	38-45	5-7

The hole will be drilled using conventional rotary drilling mud circulating equipment. Mud circulating equipment, water, and sack mud materials sufficient to maintain the capacity of the hole and circulating tanks will be on location. A closed loop mud system will be used.

Mud products to be used:

Product	Description	Function	Concentration
Barite	Barium Sulfate	Weighting Material	As required for slugs and mud weight
Gel	Bentonite	Viscosifier	15-20 ppb
Caustic Soda	Sodium Hydroxide	Alkalinity Control	0.15-0.25 ppb
PHPA	PHPA polymer	Viscosifier / Encapsulator	0.5 ppg
Drispac	Polyanionic Cellulose	Fluid Loss	0-5-1.0 ppb
Soda Ash	NA_2CO_2	Calcium Precipitant	As required
Calcium Carbonate	40/250 mesh blend	LCM Material	As required
Duro Gel	Sepiolite clay	Viscosifier	As required
Desco	Sulfomethylated Tannin	Thinner	As required
Sawdust	Sawdust	LCM	As required
Biocide	1decanaminium, n-decyl-n,n-dimethyl-,chloride, ethanol	Bacteria Control	As required
KCl	Potassium Chloride	Inhibitor	3% BWOW
Magma fiber	Spun mineral fiber	LCM	5-15 #'s/bbl
Chem Seal	Blended fibrous materials	LCM	5-15 #'s/bbl
Poly Swell	Graded size polymer	LCM	5-10 #'s/bbl
SAPP	Sodium acid pyrophosphate	dispersant	As required
Fedzan	Xanthan gum	Viscosifier	As required
KD 700	Organophosphate	Corrosion control	1.2 gal/bbl

Logging Program

Type Log Suite	Interval Top	Interval Bottom
Resistivity	Base of surface casing	TD
Density-Neutron	Base of surface casing	TD

Gamma Ray	Surface	TD

Water Source

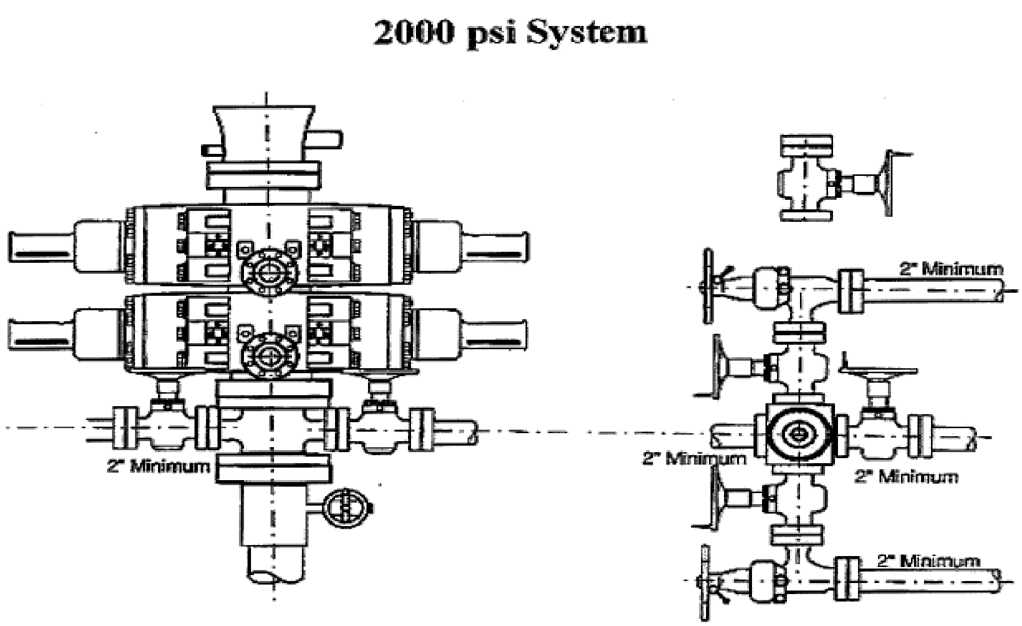
The freshwater required for the drilling operation will be trucked in from the nearest local water source.

Additional Information

1) No abnormal pressures are expected.
2) Maximum expected bottom hole pressure: 1610 psi
3) Maximum expected bottom hole temperature: 135 deg F
4) H2S is not expected.

Figure 1: Typical Blowout Preventer Diagram

2,000 psi BOP stack minimum equipment:



2M psi system:

- Double ram with blind rams and pipe rams
- Drilling spool, or blowout preventer with 2 side outlets, (choke side shall be a 2-inch minimum diameter, kill side shall be at least 2-inch diameter)
- Kill line (2 inch minimum)
- A minimum of 2 choke line valves (2 inch minimum)
- 2-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
- 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

Anticipated spud date is August 1, 2011, or as soon as permits are received. Estimated drilling time is 7 days.