NMU 11-12H
SHL: 413'FNL 1,886' FEL (NW/4 NE/4)
Sec. 11 T9N R79W
BHL: ±1,547' FSL ±264' FWL (NW/4 SW/4) Lot 16
Sec. 2 T9N R79W
Jackson County, Colorado
Surface: Federal
Federal Mineral Lease: COD28963
McCallum Federal Unit: COC47650X

DRILLING PROGRAM

(All Drilling Procedures will be followed as Per Onshore Orders No. 1 and No. 2)

This Application for Permit to Drill (APD) is filed under the Notice of Staking (NOS) process as stated in Onshore Order No. 1 (OSO 1) and supporting Bureau of Land Management (BLM) documents. This NOS process included an onsite meeting on April 25, 2014, prior to the submittal of the application, at which time the specific concerns of Bonanza Creek Energy Operating Company LLC (Bonanza Creek) and the BLM were discussed. All specific concerns of the BLM representatives are addressed herein, as are specific stipulations from the BLM.

Please contact Timothy Jayne with Bonanza Creek at, 720-440-6181, if there are any questions or concerns regarding this Drilling Program.

SURFACE ELEVATION – 8,165' (Ungraded ground elevation)

SURFACE FORMATION – Pierre Shale – Fresh water possible

1. ESTIMATED FORMATION TOPS – (Water, oil, gas and/or other mineral-bearing formations)

Formation	TVD	MD	Geology
Pierre Shale B Sand	1,312'	1,312'	Shale & sandstones
Niobrara	3,193'	3,193'	Sandstone, shale's & siltstones
Carlile	3,661'		Shale
Frontier	4,293'		Sandstone
Mowry	4,724'		Shale & siltstones
Muddy	5,045'		Shale & siltstones
Dakota	5,116'		Sandstone, shale's & siltstones
Total Depth	**5,266'**	**7,295'**	

2. ESTIMATED DEPTHS OF ANTICIPATED WATER, OIL, GAS, OR MINERAL BEARING FORMATIONS

Estimated depths at which water, oil, gas or other mineral-bearing formations are expected to be encountered:

Formation	TVD	MD	Lithology
Pierre Shale B Sand	1,312’	1,312’	Oil bearing
Niobrara	3,193’	3,193’	Oil & gas bearing
Carlile	3,661’		Some oil & gas bearing
Frontier	4,293’		Some oil, gas and/or water bearing
Mowry	4,724’		Some oil, gas and/or water bearing
Muddy	5,045’		Some oil, gas and/or water bearing
Dakota	5,116’		

All fresh water and prospectively valuable minerals encountered during drilling will be recorded by depth and protected.

3. BLOWOUT PREVENTION & PRESSURE CONTROL

- See attached blowout preventer diagram.

Blowout preventer (BOP) and related equipment (BOPE) will be installed, used, maintained, and tested in the manner necessary to assure well control and will be in place and operational prior to drilling the surface sassing show unless otherwise approved by the APD. The BOP and related control equipment will be suitable for operations in those areas which are subject to sub-freezing conditions. The BOPE will be based on known or anticipated sub-surface pressures, geologic conditions, accepted engineering practice, and surface environment. The working pressure of all BOPE will 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.

The choke manifold and accumulator will meet or exceed Colorado Oil and Gas Commission (COGCC) standards. All choke lines will be straight lines unless turns use tee blocks or are targeted with running tees, and will be anchored to prevent whip and reduce vibration. The BOP equipment will be tested when initially installed, whenever any seal subject to test pressure is broken, after any repairs to the equipment and at 30-day intervals. Pipe rams, blind rams and annular preventer will be activated on each trip and weekly BOP drills will be conducted with each crew. All tests, maintenance, and BOP drills will be documented on rig “tower sheets”.

BOP’s and choke manifold will be installed and pressure tested before drilling out of surface casing (subsequent pressure test will be performed whenever pressure seals are broken), and then will be checked daily as to mechanical operating condition. BOP’s will be pressure tested at least once every 30 days. Ram type preventers and related pressure control equipment will be pressure tested to related working pressure of the stack assembly, if a test plug is used. If a plug is not used, the stack assembly will be tested to the rated working pressure of the stack assembly, or 70% of the minimum internal yield of the casing, whichever is less. Annular type preventers will be pressure tested to 50% of their working pressure. All casing strings will be pressure tested to 0.22 psi/ft or 1,500 psi, whichever is greater, not to exceed 70% of the internal yield.

A manual locking device (i.e. hand wheels) or automatic locking devices shall be installed on the system. A valve will be installed in the closing line as close as possible to the annular preventer to act as a locking devise. The valve will be maintained the open position and will be closed only when the power source for the accumulator system is inoperative. Remote controls will be readily accessible to the driller.

Remote controls for the 5M system will be capable of closing all preventers. Master controls will be at the accumulator and will be capable of opening and closing all preventers and the choke line valves (if so equipped).

The drilling rig has not been selected for this well. Selection will take place after approval of this application is granted. Manual and/or hydraulic controls will be in compliance with BLM and COGCC standards for 5,000 psi system.

Auxiliary Equipment:
5M System:
Annular preventer, pipe ram, blind ram, and, if conditions warrant, as specified by the authorized officer, another pipe ram shall also be required, a second pipe ram preventer shall be used with a tapered drill string, 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), 3 inch diameter choke line, 2 choke line valves (3 inch minimum), kill line (2 inch minimum), 2 chokes with 1 remotely controlled from rig floor (refer to diagram in attachment 1), 2 kill line valves and a check valve (2 inch minimum), upper kelly cock valve with handle available, when the expected pressures approach working pressure of the system, 1 remote kill line tested to stack pressure (which shall run to the outer edge of the substructure and be unobstructed), lower kelly cock valve with handle available, safety valve(s) and subs to fit all drill string connections in use, inside BOP or float sub available, pressure gauge on choke manifold, all BOPE connections subjected to well pressure shall be flanged, welded, or clamped, fill-up line above the uppermost preventer.

If expected pressures approach the working pressure of the system, one remote kill line tested to stack pressure will be utilized.

HORIZONTAL DRILLING PROGRAM

A. Kick-Off-Point (KOP) is estimated to be at ±3,096’ MD.
B. The well will be drilled as a horizontal Niobrara well.

4. CASING PROGRAM

Proposed Casing:

Hole Diameter	Casing Diameter	Setting Depth	Grade	Weight (lbs/ft)	Thread/ Coupling	Condition
28”	20”	0’ – 80’	H-40	63	Welded	New
17-1/2”	13-3/8”	0’ – 250’	J-55	54.4	ST&C	New
12-1/4”	9-5/8”	0’ – 3,000’	J-55	40	LT&C	New
8-3/4”	5-1/2”	0’ – 7,200’	N-80	17	LT&C	New

Centralizers: Surface casing will have a centralizer at the shoe and on each joint.

Intermediate casing will have centralizers on shoe joint and every third joint to surface casing.

Production casing will have centralizers through curve section.

Design Criteria:

Size	Grade	Weight (lbs/ft)	Thread/ Coupling	Collapse Rating PSI	Burst Rating PSI	Joint Strength Lbs.	Safety Factor Collapse	Safety Factor Burst
13-3/8	J-55	54.4	ST&C	1130	2730	514,000	5.51	1.50
9-5/8	J-55	40	LT&C	2570	3950	452,000	2.22	2.38
5-1/2	N-80	17	LT&C	6280	7740	348,000	1.27	1.40

5. CEMENT PROGRM

Cement for Casing	Cement Interval	Cement Blend	Cement Volume (cu. ft.)	Cement Volume Sacks	Cement Mix Water (gal/sack)	Cement Weight (lbs/gal)	Cement Yield (ft3/sack	Cement Excess for calc
Conductor	0’-80’	Redi-Mix	250	50				
Surface	0’-250’	Class G Premium	347	300	5.0	15.8	1.15	100%
Intermediate Lead	0’-1,000’	Halliburton Econocem	438	250	10.27	12.50	1.89	40%
Intermediate Tail	1,000’-3,000’	Halliburton Expandacem	877	600	6.09	14.40	1.46	40%
Plugback 2 plugs	3,000’-5,266’	Class G Premium	313 each	300 each	5.0	15.8	1.15	50%
Production	3,930’-7,295’	Halliburton Expandacem	1025	702	6.09	14.40	1.46	0

Cement additives – (Note: Some additives are proprietary products. If another cement contractor is used, these blends and products may vary slightly).

Cement additives:

Surface:	Lead:	**Premium Class “G”** 2.0 lb/sk Enhancer 923 2.0% Free Water Control 0.2% Thixotropic Additive 2.0% Accelerator
	Top Out (only if necessary)	**Premium Class “G”** 2% $CaCl_2$ Fresh Water
Intermediate	Lead:	**EconoCem** 35 lb/sk Poz 5 lb/sk Bentonite 3 lb/sk Accelerator 0.2% Acid 17% Silica 0.5% LCM Fresh Water

	Tail:	**Expandacem** 35 lb/sk Poz 6 lb/sk Additive Material 3 lb.sk Additive Material 0.15% Fluid Loss 0.3% Expansion 17% Silica 0.4% Retarder Fresh Water
Plug Back		**Premium Class G** 35 lb/sk Poz 6 lb/sk Additive Material 3 lb.sk Additive Material 0.15% Fluid Loss 0.3% Expansion 17% Silica 0.4% Retarder Fresh Water
Production		**Expandacem** 35 lb/sk Poz 6 lb/sk Additive Material 3 lb.sk Additive Material 0.15% Fluid Loss 0.3% Expansion 17% Silica 0.4% Retarder Fresh Water

If necessary, 100’ of the casing top will be 1-inched with Class “G” cement.

6. MUD PROGRAM

0’	-	250’	**Spud/Fresh Water** MW: 8.4 – 8.6 ppg Viscosity (s/qt): 30 – 40 WL: NC
250’	-	3,000’	**Spud/Fresh Water** MW: 8.4 – 9.5 ppg Funnel Viscosity (s/qt): 30 – 40 WL: NC
3,000’	-	5,266	**LSND** MW: 8.6 – 9.4 ppg Funnel Viscosity (s/qt): 30-40 WL: NC
3,000’	-	7,200’	**LSND** MW: 8.6 – 9.4 ppg Funnel Viscosity (s/qt): 40-75 WL: 6 - 10

Sufficient quantities of mud materials will be maintained at the wellsite to assure well control. Specifically, 100 sx barite, 100 sx sawdust, 100 sx Walnut plug, 100 sx cedar fiber and 50 sx Mica will be kept on location to control lost circulation and to contain a "kick". Mud tests will be performed at least once per 24 hours after mud up to monitor mud weight, viscosity, water loss, pH, gel strength, etc. The mud circulating system will be monitored each tour for leaks and operation. A PVT system will be in operation to monitor pit levels. A trip tank, stroke counter and flow sensor will be in use on this well. A mud logger with gas detector and chromatograph will be in use from 3000' to TD to monitor hydrocarbon gas and pore pressure.

7. LOGGING, CORING & TESTING PROGRAM

Electric Logging:	Electric Logs at TD of the vertical pilot hole at 5,266' Triple Combo (Dual Induction Log, GR-Neutron and Density), Sonic Scanner, Magnetic Resonance, Elemental Capture Spectroscopy and FMI Logs log will be run from total depth of the pilot hole to the surface casing at 250'. A Gamma Ray log while drilling tool will be run in the horizontal lateral.
Mud Logging:	Two man mud logging unit with a gas chromatograph from the top of the Niobrara Formation at 3175' to total depth at 7,200'.
Coring:	A 60' full core is planned to be cut in the Niobrara Formation at 3,460' to 3,520' depending on actual formation tops. 100 Sidewall cores will be cut during logging operations as determined by log data.
Testing:	None Anticipated.

8. GEOLOGIC CONDITIONS

Estimated bottom-hole pressure gradient: 0.52 psi/ft
Estimated maximum bottom-hole pressure: 1,340 psi
Abnormal pressures: None anticipated
Abnormal temperatures: None anticipated
Additional potential hazards: None anticipated
Additional information:

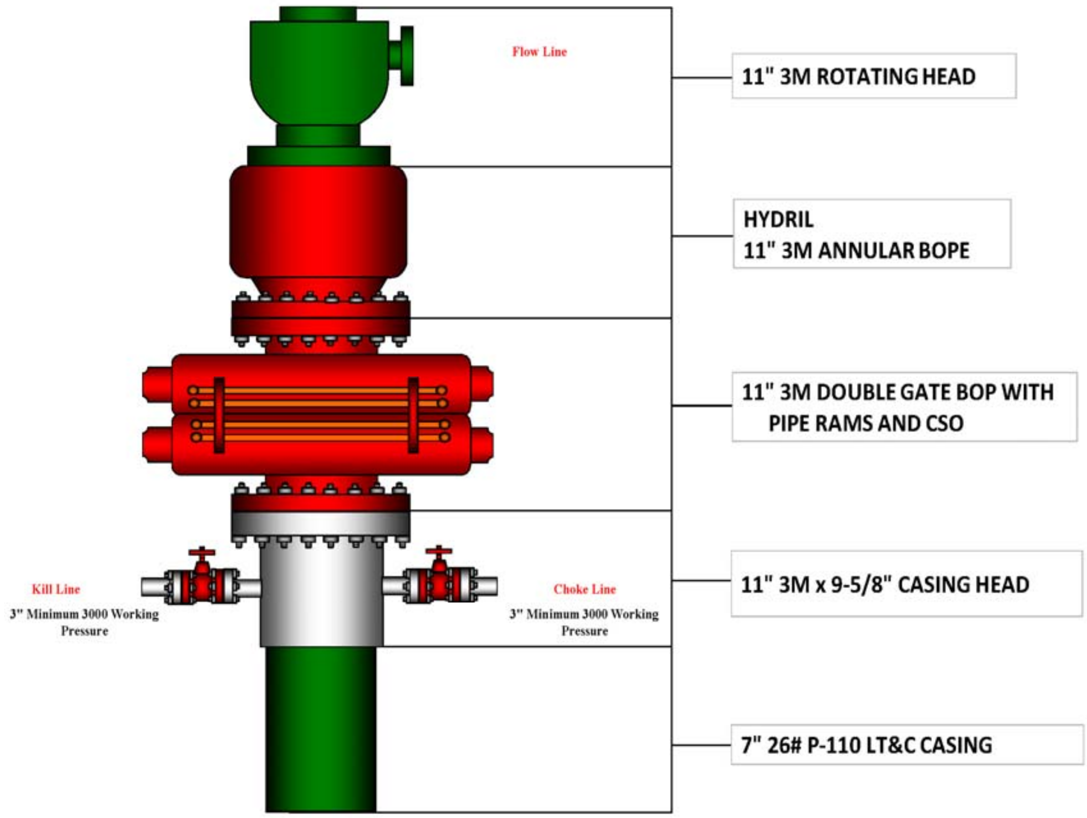
Based on data from wells in the area, it is anticipated bottomhole pressure will be 1340 psig in the Pierre "B" section of the well at 1200'. This is a gradient of 1.12 psi/ft or the equivalent of 9.3 lb/gal mud. At total depth of the pilot hole at 5266' in the Dakota/Lakota Formation, pressure is anticipated to be 750 psi. This is a pressure gradient of 0.15 psi/ft. It is anticipated that lost circulation may be encountered in this zone, but can be controlled with lost circulation materials. Anticipated bottomhole pressure in the Niobrara Formation in the horizontal lateral is expected to be 1800 psi, for a gradient of 1.2 psi/ft, or an equivalent mud weight of 9.2 lb/gal. Anticipated fracture gradient is 1.0 psi/ft. Bottomhole temperature is expected to be 125° F. No abnormal pressures or temperatures are expected.

9. ADDITIONAL FACETS OF PROPOSED OPERATIONS

August 1, 2014

Completion:
If production is indicated from log analysis and casing is run, it is anticipated the well will be completed using swell packers and frac sleeves set at approximately 250’ intervals throughout the horizontal lateral. Fracture stimulation is not anticipated for this well. If production tests indicate the well will need stimulation, it will be fractured down the 5-1/2” production casing and will be produced using 2-7/8” tubing. All production equipment necessary will be sited on the drilling location.

PROPOSED 11" BOPE FOR DRILLING 8-3/4" and 6-1/8" HOLES



PROPOSED 3" 5M CHOKE MANIFOLD

All valves and fittings 3" Min ID with 5000 psi Working Pressure