OCD Hobbs

ATS-15-155

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Form 3160-3
(March 2012)

FORM APPROVED
OMB No. 1004-0137
Expires October 31, 2014

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

APPLICATION FOR PERMIT TO DRILL OR REENTER

1a. Type of work: ☐ DRILL ☑ REENTER	5. Lease Serial No. NMNM90558
	6. If Indian, Allotee or Tribe Name
	7. If Unit or CA Agreement, Name and No.
1b. Type of Well: ☑ Oil Well ☐ Gas Well ☐ Other ☑ Single Zone ☐ Multiple Zone	8. Lease Name and Well No. Fowler Federal #1 315674
2. Name of Operator Spindletop Oil & Gas Co. (212092)	9. API Well No. 30-025-38408
3a. Address 12850 Spurling Road, #200 Dallas, Texas 75230 — 3b. Phone No. *(include area code)* 972-644-2581	10. Field and Pool, or Exploratory Fowler East (Ellenburger) (26500)
4. Location of Well *(Report location clearly and in accordance with any State requirements.*)* At surface 330' FNL & 1,650' FEL; At proposed prod. zone ~~330' FNL & 1,280' FEL~~	11. Sec., T. R. M. or Blk. and Survey or Area Sec. 18, T 24S, R 38E
14. Distance in miles and direction from nearest town or post office* 6 miles northeast of Jal	12. County or Parish Lea — 13. State NM

15. Distance from proposed* location to nearest property or lease line, ft. (Also to nearest drig. unit line, if any) 330'	16. No. of acres in lease 320 ac.	17. Spacing Unit dedicated to this well 40 ac.
18. Distance from proposed location* to nearest well, drilling, completed, applied for, on this lease, ft. 1,250'	19. Proposed Depth 11,700	20. BLM/BIA Bond No. on file NMB000951 (BLM)
21. Elevations (Show whether DF, KDB, RT, GL, etc.) G.L. 3,195'	22. Approximate date work will start* 12/31/2014	23. Estimated duration 45 days

24. Attachments

The following, completed in accordance with the requirements of Onshore Oil and Gas Order No.1, must be attached to this form:

1. Well plat certified by a registered surveyor.
2. A Drilling Plan.
3. A Surface Use Plan (if the location is on National Forest System Lands, the SUPO must be filed with the appropriate Forest Service Office).
4. Bond to cover the operations unless covered by an existing bond on file (see Item 20 above).
5. Operator certification
6. Such other site specific information and/or plans as may be required by the BLM.

25. Signature	Name *(Printed/Typed)* Chuck D. Howell	Date 09/30/2014
Title Senior Geologist		
Approved by *(Signature)* Ed Fernandez acting for Steve Caffey	Name *(Printed/Typed)*	Date NOV 13 2015
Title FIELD MANAGER	Office CARLSBAD FIELD OFFICE	

Application approval does not warrant or certify that the applicant holds legal or equitable title to those rights in the subject lease which would entitle the applicant to conduct operations thereon.
Conditions of approval, if any, are attached.

APPROVAL FOR TWO YEARS

Title 18 U.S.C. Section 1001 and Title 43 U.S.C. Section 1212, make it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

(Continued on page 2)

KZ 11/23/15

*(Instructions on page 2)

Capitan Controlled Water Basin

Approval Subject to General Requirements & Special Stipulations Attached

SEE ATTACHED FOR CONDITIONS OF APPROVAL

DEC 10 2015

SECTION 1

DRILLING PLAN

1.1 Overview:

This well plan is for a re-entry and side track procedure for the Fowler Federal, Well No. 1 previously drilled and plugged by par Minerals in 2007.

Spindletop Oil & Gas Co. will drill a 7 ⅝" side track hole out of the existing open hole to the planned total depth. In the existing hole, the surface casing is set to 1,425 ft. and intermediate casing is set to 5,999 ft. and the exisiting open hole will be utilized to side track the Fowler Federal, Well No. 1.

Spindletop Oil & Gas Co.'s planned operation on the Fowler Federal, Well No. 1 will be to drill a side track well, holding a constant tangent angle until reaching total depth in the Ellenburger Formation. The side track's bottom hole location will be approximately 370' due east of the well's surface hole location.

A class H cement plug was placed in the Fowler Federal, Well No.1 from 7,615 ft. through 7,871 ft. above a fish left in the hole (top of fish at 7,871 ft.). The planned kick-off point is at approximately 7,600 ft. at which depth a trough will begin being cut on the low side of the exisiting well bore. The side track plan is to test and kick off of the existing cement plug using a near bit fixed bend 1.83° motor. The existing well bore has an inclination of approximately 2° and an azimuth between 260° and 267°. The estimated kick-off point is between 7,600 ft. and 7,871 ft. measured depth. A 5, 4, 3, 2, 1, minute timed-drilling technique will be used to establish and begin drilling the side track well bore. The planned side track will build to an approximate 5° angle which is expected to be reached at about 7,941 ft. measured depth and then hold a tangent angle drilling a slant until the side-track reaches an expected total measured depth of 11,606.18 ft. (approximately a true vertical depth of 11,590 ft.). If we are unsuccessful kicking off of the existing cement plug Spindletop Oil & Gas Co. plans to set a class H cement kick off plug in the open hole between 7,200 ft. and 7,615 ft. and to attempt to kick off the well using an identical 5, 4, 3, 2, 1 minute timed-drilling technique. Alternatively, a whipstock may be placed in the well to successfully kick off. Once the well is successfully kicked off any necessary small adjustments will be made to the drilling plan's tangent angle and azimuth angle (likely falling somewhere between 4° and 5° depending at what point the well is kicked off) to drill to the planned for side track bottom hole location.

1.2 Casing Program:

All casing is new and API approved. The minimum safety factors required according to Onshore Order No. 2 are: Collapse = 1.125, Burst = 1.2, Tension = 1.8. The design factors for the casing strings (existing and proposed) are shown in Table 1.2.1. The surface and intermediate casing is *ALREADY* been installed and cemented in the Fowler Federal, Well No. 1.

At TD, a 5 ½" production liner along with a packer shoe and a multistage tool, if needed, will be run in and set to a depth of approximately 11,430 ft. within the top 100 ft. of the Ellenburger Fm. and the 5 ½" liner will be cemented in. A multi-stage DV tool, if it is determined to be needed, will be placed between 9,000 ft. and 8,000 ft. depending on the integrity of rock encountered in the side track well bore while drilling. Cement will be pumped in above the Ellenburger open-hole completion.

Table 1.2.1. Casing Design and Safety Factors

Casing Summary						**psi**			**Safety Factors**		
Hole Diam.	***Casing OD***	***Depth***	***Weight***	***Grade***	***Type***	***Coll.***	***Burst***	***Joint***	***Coll.***	***Burst***	***Jt. Yield***
*14 ¾"	11 ¾"	1,425'	42#	H-40	STC	1,070#	1,980#	307 kpsi	1.125	1.2	1.8
*11"	8 ⅝"	5,999'	32#.	J-55	LTC	2,530#	3,930#	417 kpsi	1.125	1.2	1.8
7 ⅞" & 7 ⅝"	5 ½"	11,700'	17#.	N-80	LTC	6,390#	7,740#	348 kpsi	1.125	1.2	1.8

1.3 Cementing Program:

1.3.1 5 1/2" Production Liner:

* See COA

A 5 ½" production liner will be hung in intermediate casing using a liner hanger that is set at approximately 5,699 ft. Alternatively, the 5 ½' production casing may be ran back to the surface. The production liner with an open hole casing packer shoe will be ran and set just into the upper beds of the Ellenburger dolomite to an estimated measured depth between 11,400 ft. and 11,600 ft.. A multi-stage DV tool will be placed between 9,000 ft. and 8,000 ft. depending on the integrity and quality of rock at these depths encountered in the side track well bore and cement will be raised from the packer shoe to the liner hanger at 300 ft. inside intermediate casing providing sufficient overlap within the existing intermediate casing. The Fowler Federal, Well No. 1 side track 01 will be an open-hole Ellenburger completion attempt as is locally typically done. The reservoir is an under-pressured fractured dolomite that can be severely damaged by placing cement across the interval. Spindletop Oil & Gas Co. will complete the well naturally or if needed place acid into the Ellenburger reservoir.

Table 1.3.1. Cement Summary Table

Cement Program					
Hole Diam.	***Casing OD***	***Top Depth***	***Bottom Depth***	***Sacks + 20%***	***Yield***
7.925"	**5 ½"**	**5,699'**	**5,999'**	**19**	**2.83**
7 ⅝"	**5 ½"**	**5,999'**	**10,430'**	**288**	**2.83**
7 ⅝"	**5 ½"**	**10,430'**	**11,430'**	**124**	**1.45**

1.3.2 Lead Slurry:

307 sacks of 9.00 ppg. cement, expected thickening time – 70Bc at 08:37 hours. Expected fluid loss: 39 mL in 12 minutes. Additives: Anti-foamer 0.2% BWOB; Dispersant 0.1% BWOB; Fluid loss 0.4% BWOB; Retarder 0.2% BWOB; Expanding agent 2.0% BWOB. Yield 2.83 cf/sack. 1,200 psi compressive strength @ 24 hours. 1,400 psi compressive strength @ 72 hours.

* see COA

Single-stage Cementing Program						
Casing	Number of Sacks	Wt. lb/gal.	H_2O gal./sack	Yield ft3/sack	500# Comp. Strength (hours)	Slurry description
5.5" Prod. Single stage option	307	9	10.541	2.83	10 hr 17 min	Cement + 0.4% BWOB Fluid loss + 0.2% BWOB Anti Foam + 2% BWOB Expanding Agent + 0.2% Retarder + 0.1% dispersant BWOB.
	124	13.2	7.073	1.45	48 hr 15 min	Cement + 0.4% BWOB Fluid loss + 3 lb/sk WBWOB Extender + 0.2% BWOB Anti Foam + 2% BWOB Expanding Agent + 1.1% Retarder + 2lb/sk WBWOB Mica Medium + 2lb/sk WBWOB Mica Coarse.

* see COA

Optional 2-stage Cementing Program						
Casing	Number of Sacks	Wt. lb/gal.	H_2O gal./sack	Yield ft3/sack	500# Comp. Strength (hours)	Slurry description
5.5" Prod. Two stage option	260	13.2	7.073	1.45	48 hr 15 min	Cement + 0.4% BWOB Fluid loss + 3 lb/sk WBWOB Extender + 0.2% BWOB Anti Foam + 2% BWOB Expanding Agent + 1.1% Retarder + 2lb/sk WBWOB Mica Medium + 2lb/sk WBWOB Mica Coarse.
	DV Tool at 10,000'					
	240	9	10.541	2.83	10 hr 17 min	Cement + 0.4% BWOB Fluid loss + 0.2% BWOB Anti Foam + 2% BWOB Expanding Agent + 0.2% Retarder + 0.1% dispersant BWOB.
	100	13	7.314	1.42	13 hr 36 min	Cement + 0.4% BWOB Fluid loss + 0.2% BWOB Anti Foam + 2% BWOB Expanding Agent + 0.6% Retarder + 0.1% dispersant BWOB.

DV tool depth(s) will be adjusted based on hole conditions and cement volumes will be adjusted proportionally. DV tool will be set a minimum of 50 feet below previous casing and a minimum of 200 feet above current shoe. Lab reports with the 500 psi compressive strength time for the cement will be onsite for review.

1.3.3 Tail Slurry:

124 sacks 13.2 ppg. of cement. Expected fluid loss: 53 mL in 30.0 minutes. Additives: Fluid Loss 0.4% BWOB; Extender 3 lb. / sack WBWOB; Anti Foam 0.2% BWOB; Retarder 1.1% BWOB; Mica (medium) 2 lb. / sack WBWOB; Mica (coarse) 2 lb./ sack. Yield 1.45 cf/sack. 1,500 psi compressive strength @ 24 hours. 1,500 psi compressive strength @ 24 hours

1.3.4. Cementing Procedures (Please note that these procedures are for a single stage cementing job and that volumes will need to be adjusted if it is determined a multi-stage tool is needed)

1) Rig up cementers
2) Confirm well data and calculations with cementing contractor (water displacement volume).
3) Check mud properties and record mud yield point, viscosity, and density for cementing
4) Verify rig's circulating pressure prior to start of cementing job.
5) Conduct a safety and procedure meeting with all personnel present before treatment begins. Go over contingencies, recommendations and plans. Well must be circulated a minimum of 2X bottoms up with casing on bottom prior to cementing.
6) Batch Mix 30.0 bbls, 12.0 ppg Losseal pill in advance
7) Pressure test treating lines to 300 psi (low) and 5,000 psi (high)
8) Pump 30.0 bbls of 12.0 ppg Losseal pill ahead
9) Pump 300.0 bbls of 8.80 ppg location water base mud @ 3.5 to 4.0 bpm behind
10) Pump 30.0 bbls freshwater ahead at 3.5 to 4.0 bpm rates.
11) Mix and pump 30.0 bbls MUDPUSH Express* (MPE) spacer at 8.9 ppg density and 3.5 to 4.0 bpm rates.
12) Mix 307 sacks of 9.0 ppg lead slurry and pump at 3.5 to 4.0 bpm rates. If slurry density varies more than 0.2 ppg from the design density, then stop pumping downhole and recirculate slurry in mix tub until density is within range.
13) Mix 124 sacks of 13.2 ppg regular PVL tail slurry and pump at 3.5 to 4.0 bpm rates. If slurry density varies more than 0.2 ppg from the design density, then stop pumping downhole and recirculate slurry in mix tub until density is within range.
14) Shut-down and wash-up surface lines and drop drill pipe wiper dart.

15) Start displacement with fresh water behind at 3.5 to 4.0 bpm rates
16) Continue to displace with location water.
17) Bump top wiper plug with 500psi over (NOTE: do not over-displace)
18) Bleed back pressure to ensure the float is holding
19) Rig to PU liner running tool above TOL and reverse circulate cement clean to surface.
20) Shut down wash-up pump to pit, remember to add sugar to pit, and rig down cementers and wait on cement
21) Notes:
    a. 124 sacks lead tail slurry - minimum slurry volume pumped in order to start displacement in the event of a failure
    b. 20 minutes - maximum allowable shutdown time after slurry mixing as per lab instructions.

1.4 Pressure Control: * See COA

The blowout preventer equipment (BOP), shown in exhibit A, will consist of a double ram-type (5,000 psi W. P.) preventer and an annular preventer (5,000 psi W. P.). Units will be hydraulically operated and the ram-type will be equipped with blind rams on top and drill pipe rams on the bottom. All will be installed on the 11 ¾" surface casing and used continuously until total depth is reached. The ram-type BOP and all accessory equipment will be tested to 5,000 psi and the annular preventer to 70% of the rated working pressure (3,500 psi).

Pipe rams will be operationally checked each 24 hour period. Blind rams will be operationally checked on each trip out of the hole. These checks will be noted on the daily tour sheets. A 2 inch kill line and 4 inch choke line will be included in the drilling spool located below the ram-type BOP. Other accessories to the BOP equipment will include a Kelly cock and floor safety valve (inside BOP) and choke lines and choke manifold with 5,000 psi W. P.

Additional BOP accessories include an upper and lower kelly cock with the locking handle readily available on the rig floor at all times, the choke operating controls and floor safety valves are on the rig floor and pit fluid level sensors are used to monitor pit levels.

Mud monitoring equipment shall be placed on the circulating tanks to detect any abnormal volume changes, (i.e. loss or gain) of the mud system as stated in Onshore Order 2. This equipment shall be made of a pit level indicator and flow line sensor.

See The H_2S Contingency Plan will include placement of H_2S and $S0_2$ gas sensor equipment is to be mounted at the return flow line, bell nipple and rig floor by an independent contractor.

Derrick floor indicators with audio/visual alarms shall be installed and operative before drilling out from underneath casing.

A gas separator shall be installed as required by the BLM. A flare system shall be designed to gather and burn all gas. The discharge shall be no less than 150 feet from the well head, downwind from the prevailing wind direction. A single choke line may be diverted to the separator to vent gas or circulated to mud tanks when and where deemed necessary. The secondary gas vent line shall be buried from separator to the flare area. The bleed line shall remain independent and shall be buried after the choke to the flare area which will be 150 feet minimum from the cellar. A third choke line shall run to the return mud tank. All choke lines can be controlled independently.

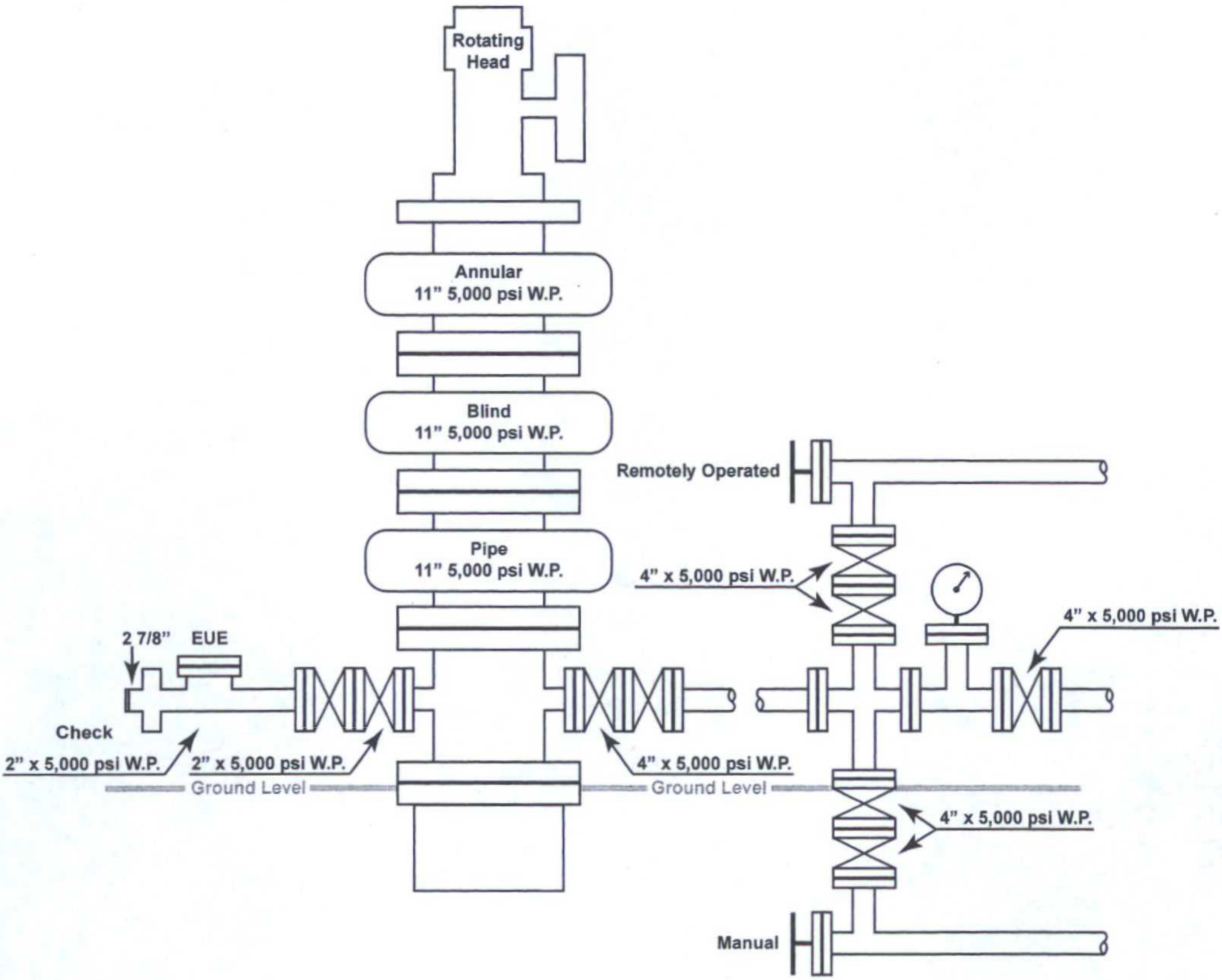
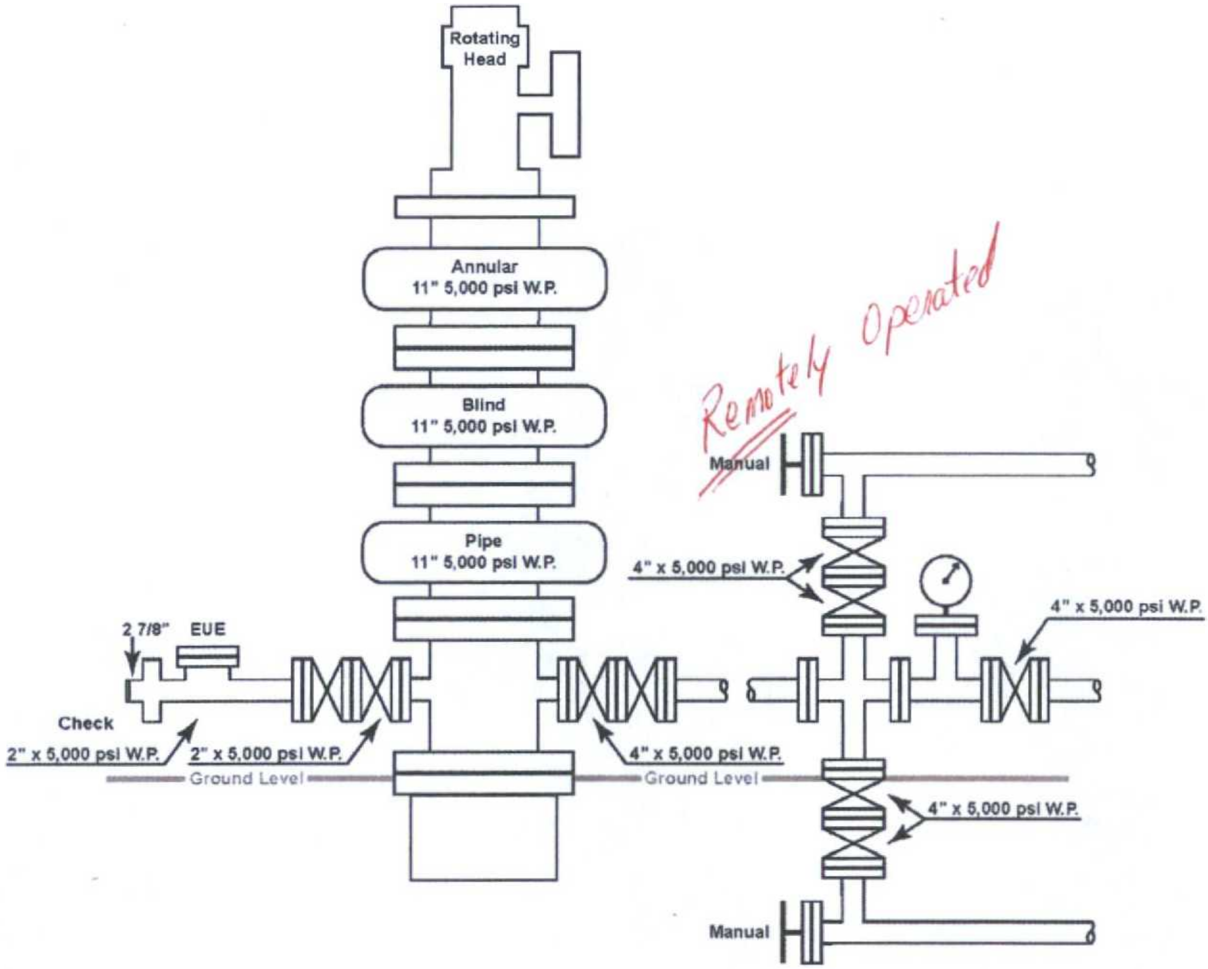

Rotating
Head
Annular
11" 5,000 psi W.P.
Blind
11" 5,000 psi W.P.
Pipe
11" 5,000 psi W.P.
Remotely Operated
4" x 5,000 psi W.P.
4" x 5,000 psi W.P.
2 7/8" EUE
Check
2" x 5,000 psi W.P.
2" x 5,000 psi W.P.
4" x 5,000 psi W.P.
Ground Level
Ground Level
4" x 5,000 psi W.P.
Manual

Exhibit 1.4.1



B.O.P. diagram

A) Drilling nipple to be so constructed that it can be removed without use of a welder through rotary table opening`, with a minimum inner diameter equal to the preventer bore.

B) Wear ring to be properly installed in head.

C) Blow out preventer and all fittings must be in good condition, 5,000 psi W. P. minimum.

D) All fittings to be flanged.

E) Safety valve must be available on rig floor at all times with proper connections, valve to be full-bore 5,000 psi W. P. minimum.

F) All choke and fill lines to be securely anchored, especially the ends of choke lines.

G) Equipment through which bit must pass shall be at least as large as the diameter of the casing being drilled through.

H) Kelly cock on Kelly.

I) Extension wrenches and hand wheels to be properly installed.

J) Blow our preventer control to be located as close to the driller's position as feasible.

K) Blow out preventer closing equipment to include minimum 40 gallon accumulator, two independent sources of pump power on each closing unit installation, and must meet all API specifications.

1.5 Drilling Fluid Program:

The well will be drilled to total depth using a freshwater mud system. Mud weights will be kept very low drilling out from underneath intermediate casing. Pit volumes will be monitored both visually and with electronic sensors. Pit volumes will also be monitored remotely via Pason Systems. The applicable depths and properties of this system are outlined in the table provided below, and generally, they are as follows:

Table 1.5.1 Planned Drilling Fluid Program Summary Table

Depth	Type	Weight (ppg)	Viscosity (sec)	Waterloss (cc)
5,999 ft. to ~8,500 ft.	Freshwater/Bentonite/Low Solids	8.4	28	N/A
8,500' to TD	Freshwater/Bentonite/Low Solids	8.4 – 8.9	36 - 45	N/A

* See COA

Sufficient mud materials to maintain mud properties and meet minimum lost circulation and weight increase requirements will be kept on location at the well-site at all times. Hydrogen Sulfide (H_2S) scavengers will be used if any signs of H_2S are present. There has been *no* H_2S encountered or reported during the drilling operations in any offset wells on this lease and none was encountered in any offset wells in our surrounding leases.

Freshwater mud will be used while drilling the side track hole to obtain optimum hole stability first utilizing a weight gradient of 0.42 lbs./ft. to aid in suppressing any invasion of unexpected oil or gas and to maintain hole stability. Mud materials shall be readily available should the need arise for lost circulation or well control purposes.

1.6 Auxiliary Well Control and Monitoring Equipment:

A) A Kelly cock will be kept in the drill string at all times

B) A full opening drill pipe stabbing valve (inside BOP) with proper drill pipe connections will be on the rig floor at all times

1.7 Testing, Logging and Coring Program: * See COA

1.7.1 Drill Stem Tests:

The number of drill stem tests will be on an as determined basis.

1.7.2 Electrical Logging:

TD to intermediate casing: GR, IND, DLL, MSFL, POR.

The electric logging program will consist of Gamma Ray, Dual Latero, Micro-spherically Focused from total depth to the base of the intermediate casing. A Gamma Ray and Compensated Density Neutron or Sonic log may be ran across various intervals as determined from induction logs within the interval found from TD up to the base intermediate casing. Please note that a full suite of electric logs were ran in the original Foweler Federal, Well No. 1 from TD to base of surface casing.

1.7.3 Mud Logging:

A mud logging contractor may be placed in operations within a reasonable amount of time upon before drilling out from under the Simpson Group. The planned side track well is an in-field infill location and a mudlogger may not be utilized.

1.8 Potential Hazards:

No abnormal pressures or temperatures are anticipated. The Ellenburger Formation is an under-pressured zone that is partially depleted. Bottom hole pressure is not expected to exceed 5,000 psi, (11,600' x .42 psi/ft). Estimated BHT is 175° F. There is no H_2S or other hazardous gas encountered nor is reported to be in area wells nor has any been reported from on the lease. The operator will however have an H_2S Contingency Plan in See COA place. The H_2S Contingency Plan is attached.

1.9 Anticipated Start Date:

We plan to start within the two year permit period once the APD is approved and contractors are scheduled. It should take approximately 45 days to drill the side track well. It is expected to take another 30 to 45 days to complete the well. This well is ***not*** located in the known Lesser Prairie Chicken crucial habitat.

1.10 Surface and Minerals Ownership:

The surface is private land owned by William Jarvis Grobe, P. O. Box G, Jal, New Mexico, 88252. The mineral ownership is USA and managed by the Bureau of Land Management.

THE OPERATOR HAS A SURFACE USE LAND AGREEMENT WITH THE PRIVATE LAND OWNER.

AN ONSITE INSPECTION MEETING WAS DONE ON 09/16/2014 WITH THE BLM AND WAS CONDUCTED BY MS. TRISHIA BAD BEAR.

SECTION 2

GENERAL INFORMATION

2.1 Overview:

Geologic Name of Surface Formation: Permian

2.1.1: Pressure and/or Maximum Mud Weight:

No high pressure zones in offset wells.

2.1.2: Lost Circulation Zones:

Slow seepage problems can be expected at 8,000 ft. to TD. The Mary Kay Evans (2 miles to the east) and the South Mattix #32 (2 ¼ miles southwest) experienced seepage at 8,000 ft. and 9,000 ft. respectively.

2.1.3: Deviation:

This is crooked-hole country. Directional tools will be used while drilling.

2.1.4: The Dollarhide / Drinkard Unit:

Located 2 miles south, is a waterflood with water being injected at 3,500 ft. through 4,000 ft. into the Queen at an injection pressure of 1,400 psi and is injected at 6,000 ft. through 6,500' into the Drinkard at 1,700 psi

2.1.5: Geological Name of Surface Formation:

Permian, Quaternary alluvium deposit

2.1.6: Estimated Tops of Anticipated Oil, Gas or Saltwater-Bearing Zones:

San Andres ~4,400 ft. non-bearing Oil, Gas or Water
(Aready behind casing and cemented)

Glorietta (Already behind casing and cemented)	~5,573 ft.	Possible Oil, Gas or Saltwater
Tubb	~6,576 ft.	Possible Oil, Gas or Saltwater
Drinkard/Bone Spring	~6,688 ft.	Possible Oil, Gas or Saltwater
Abo	~7,058 ft.	Possible Oil, Gas or Saltwater
Devonian	~8,850 ft.	Possible Oil, Gas or Saltwater
Simpson	~10,720 ft.	Possible Oil, Gas or Saltwater
Ellenburger	~11,430 ft.	Oil
Permit Total Depth (MD)	11,700 ft.	

No other formations are anticipated to yield oil, gas or water in measureable or significant volumes.

2.2.2 Company Contact Information:

2.2.1 Physical Address:

Spindletop Oil & Gas Co.
12850 Spurling Road, Suite 200
Dallas, Texas 75230

2.2.2 Main Telephone Number:

Office .... Main (972) 644-2581

2.2.3 Contact Information - Geology:

Chuck Howell .... Cell (214) 532-7583
Office (214) 972-644-2581 ext. 268

Michael Boos .... Cell (214) 991-7991
Office (214) 972-644-2581 ext. 249

2.2.4 Contact Information – Engineering:

Dave Chivvis.......... Cell (214) 546-0179
Office (214) 972-644-2581 ext. 272

David Owen .... Cell (214) 577-0554
Office (214) 972-644-2581 ext. 237