PRAIRIE PROVIDENT RESOURCES CANADA LTD.
ABANDONMENT INFORMATION PACKAGE

S. POINTED MOUNTAIN (D-1) L-68
300/L-68-60-20-123-45/1

DEVIATED WELL

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1 WELL DATA

Operator:	Prairie Provident Resources Canada Ltd. 1110, 640 – 5th Avenue SW Calgary, Alberta T2P 3G4		
24 Hour Emergency #:	1-866-405-4854		
Coordinates:	60°17'42.83"N 123°57'55.91"W		
Elevations:	**KB:**	737.0 m	**KB – THF:** 4.7 m
	GL:	723.0 m	
	PBTD:	3971.0 mKB MD	
	TD:	4200.0 mKB MD / 4139.86 mTVD	

Maximum deviation: ~31.25° at 3714 mMD
See attached directional surveys

Conductor Casing: 508.0 mm, 139.89 kg/m, S00-95 LT&C landed at 165.0 mKB. (Cemented with 55 tonnes Oilwell Neat G cement, 100% returns) – 660 mm open-hole

Surface Casing: 339.7 mm, 107.15 kg/m, S00-95 LT&C landed at 1424.0 mKB (Cemented with 3 blends: 42.7 tonnes Class G + 2% gel (0:1:2); 64.8 tonnes Class G + 8% gel (0:1:8); and 13.2 tonnes Class G neat (0:1:0), full returns) – 445 mm open-hole

Intermediate Casing: 244.5 mm, 64.7 kg/m, S00-95 LT&C landed at 3297.0 mKB (External casing packer at 1367.82 mKB. Cemented with 122.3 m³ class G + 8% gel (33.3 tonnes 0:1:0 G, 103.3 tonnes 9:1:8), hole bridged off after 89.5 m³ displaced, ECP was set with 32.8 m³ cement left in casing) – 311 mm open-hole

Liner: 177.8 mm, 38.69 kg/m, S00-95 LT&C from 3234.88 to 4130.0 mKB (Cemented with 24 m³ class G cement + 30% Silica flour, received 2.3 m³ cement returns to surface) – 216 mm open-hole

Frac string (permanent): 114.3 mm, 22.47 kg/m, P-110 casing from 3217.2 to 3899.71 mKB with permanent liner top packer set at 3217.2 mKB. Ball actuated frac sleeves with ARES two stage hydraulic set packers, and permanent packer on bottom of string (see details on wellbore diagram) – 10K WR plug set at 3339 mKB

Tie-back string: 139.7 mm, 34.23 kg/m, P-110, LT&C casing joints, latched into permanent liner packer at 3217.2 mKB to surface.

Whipstock: Whipstock plug set at 4083.6 mKB inside 177.8 mm liner, window cut in liner at 4078.89 mKB and drilled to 4200 m.

Perforations: See perforations table below

Wellhead: 279.4 mm x 139.7 mm 69 MPa flowing style bonnet

Base of Groundwater Protection: 614.0 mKB (600 m below ground level)

OBJECTIVE: Abandon well as per OROGO regulations, repair SCVF and cut and cap.

Table 1 – Tubular Data

	Production Casing	**Tie-back string**	**Frac String**	**Workstring**
Size OD [mm]	244.5	139.7	114.3	
Size ID [mm]	222.38	118.62	99.57	
Weight [kg/m]	64.74	34.23	20.09	
Grade	S-95	P-110	P-110	
Drift [mm]	218.42	115.44	96.39	
Capacity [m³/m]	0.038840	0.011051	0.0078	
Annular Capacity [m³/m]	0.023511 (139.7 mm inside string)	-	-	
Collapse [MPa]	38.6	100	73.6	
Burst [MPa]	51.8	94	85.6	
Tension [1000 daN]	-	286	197	

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Table 2 – Perforations, open-hole details

Perf Date	Formation	Top Shot	Bottom Shot	Status	Gun Data
5-Sep-11	Exshaw	3351.00	3356.00	Suspended	17 SPM, 25 gr, 60°
5-Sep-11	Exshaw	3365.00	3370.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3784.00	3789.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3805.00	3810.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3935.00	3940.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3948.00	3953.00	Suspended	17 SPM, 25 gr, 60°
12-Oct-82	Nahanni	4079.80	4200.00	Abandoned	Whip-stock, 153 mm open-hole
13-Sep-82	Nahanni	4130.00	4200.00	Abandoned	216 mm Open-hole

2 Detailed Well History

Amoco Canada Petroleum Company Ltd. began its operations on Amoco S. Pointed Mountain (D-1) L-68 in January 1982. Upon completion of surveying, and access road and location construction, the well was spudded on March 3, 1982. Drilling and completion operations concluded with the abandonment of the well and subsequent release of the rig Hi-Tower #4 on November 4, 1982.

The original drilling summary scans are attached, and detailed below:

Date	Summary of Drilling Operations
1982-02-06	Construction of lease and road begins.
1982-03-09	Rig move to lease.
1982-03-25	Spudded well at 0930 hours. Drilled 445 mm pilot hole. Drilling rig: Hi-Tower #4.
1982-03-31	Finished drilling 445 mm pilot hole to 189 m. Opened hole to 660 mm.
1982-04-09	660 mm hole opened to 165 m. Ran 508 mm casing to 165 m. Cemented with 55 tonnes Oilwell Neat G cement. 100% returns.
1982-04-12	Rigged up diverter, tested to 3500 kPa for 15 minutes. Drilled out cement and began drilling 445 mm hole.
1982-04-21	Encountered drilling break at 577 m. Fresh water kick from formation. Controlled with 1184 kg/m³ mud, drilling resumed with 1200 kg/m³ mud.
1982-05-14	Converted mud system to fresh formation water. Depth 1065 m.
1982-05-20	Sour gas bubbling to surface, convert mud system back to gel-benex mud, density 1200 kg/m³. Depth 1227 mKB.
1982-06-07	Depth 1424 m. Ran 340 mm, 107 kg/m casing. Cemented with 42.7 tonnes Class "G" + 2% gel, 64.8 tonnes Class "G" + 8 % gel, and 13.2 tonnes Class "G" tail in. Full returns.
1982-06-13	Nippled up BOP's. Tested to 31,000 kPa for 15 minutes. Drilled out cement for 311 mm hole. Performed leak off test, surface pressure 12,400 kPa with 1150 kg/m³ mud at 1434 m. Frac gradient of 19.9 kPa/m. Resumed drilling 311 mm hole.
1982-06-15	Encountering slight deviation problems at 1519 m. Inclination of 5.25°. Added stabilizers to BHA and reduced WOB to combat angle building.
1982-07-05	Depth 2373 m. Encountering severe gas cutting in mud. Combatted by increasing mud weight to 1150 kg/m³ diverting mud through poorboy degasser and drilling with a 1.5 m flare.

1982-07-11	Gas kick at 2679 m with 1125 kg/m³ mud, 7.5 m³ / 45 min pit gain. SICP 3800 kPa, SIDP 100 kPa. Circulated out dick with 1140 kg/m³ mud.
1982-07-24	Deviation off scale on recording device, great than 8° inclination. RIH with strong dropping BHA.
1982-07-29	Reached casing point of 3297 mKB. Hole suffering from severely sloughing shales. Tried to condition hole for logging.
1982-08-08	Logging program waived by government due to hole programs. Ran 245 mm, 64.7 kg/m, S0095 casing to 3297 m, with a Lynes External Casing Packer at 1367.82 m. Cemented with 122.3 m³ neat G + 8% gel, hole bridged off after 89.5 m³ displaced. ECP is set and 32.8 m³ cement left in casing.
1982-08-10	Cement top at 2434 m, drilled out cement to 3285 m. Ran gyro-survey and cased hole logs.
1982-08-14	Drilled out shoe and drilled 216 mm hole.
1982-09-05	Drilled to T.D. of 4200 m, ran multishot survey. Logged.
1982-09-13	Ran 177.8 mm liner, hung at 3234.88 m and land at 4130 mKB. Cemented with 24 m³ Class "G" cement plus 30% Silica flour. Received 2.3 m³ cement returns at surface.
1982-09-16	While drilling out cement, could not get by 4103 mKB. Parted liner suspected. Attempted milling through.
1982-10-01	Whipstocking tool set at 4083.6 m. Window cut in liner at 4078.89 m.
1982-10-12	Reached T.D. of 4200 m with 153 mm bit.

Date	Summary of Initial Completion & Abandonment Operations
1982-10-15	Set packer at 4070 m, RIH with 88.9 mm C.S. Hydril tubing. While pressure testing annulus to 34,000 kPa, tubing collapsed.
1982-10-16	Fishing operations initiated.
1982-10-29	Fish fully retrieved. Ran Halliburton RTTS tool to perform DST. No fluid inflow recorded on DST.
1982-10-30	Set new packer at 4165 m. RIH with new 88.9 mm C.S. Hydril tubing string. Set 1 m³ 28% HCl across Nahanni in attempt to initiate feed rate. Surface pressure of 49,630 kPa applied at surface, negligible feed rate.
1982-11-01	Latched Baker DR plug into packer. Ran cement plug #1: 4005 to 40065 m with 1.5 m³ Oilwell Neat G cement. Ran cement plug #2: 3207 to 3267 m with 1.6 m³ Oilwell Neat G cement. Plug # 2 tagged at 3206 m.

1982-11-04	Rig released at 1982-11-04 at 0800 hours. All equipment to be left on location until winter when ice bridge is built. Sump will be treated and cleaned up during the winter months as well.
1982-11 (date unknown)	Cut and capped casings at surface with welded plate at 400 L Neat G cement.

Note: at the time in 1982, this well was abandoned in accordance with regulations. The original Nahanni open-hole completion remains abandoned as per the original abandonment requirements to this day.

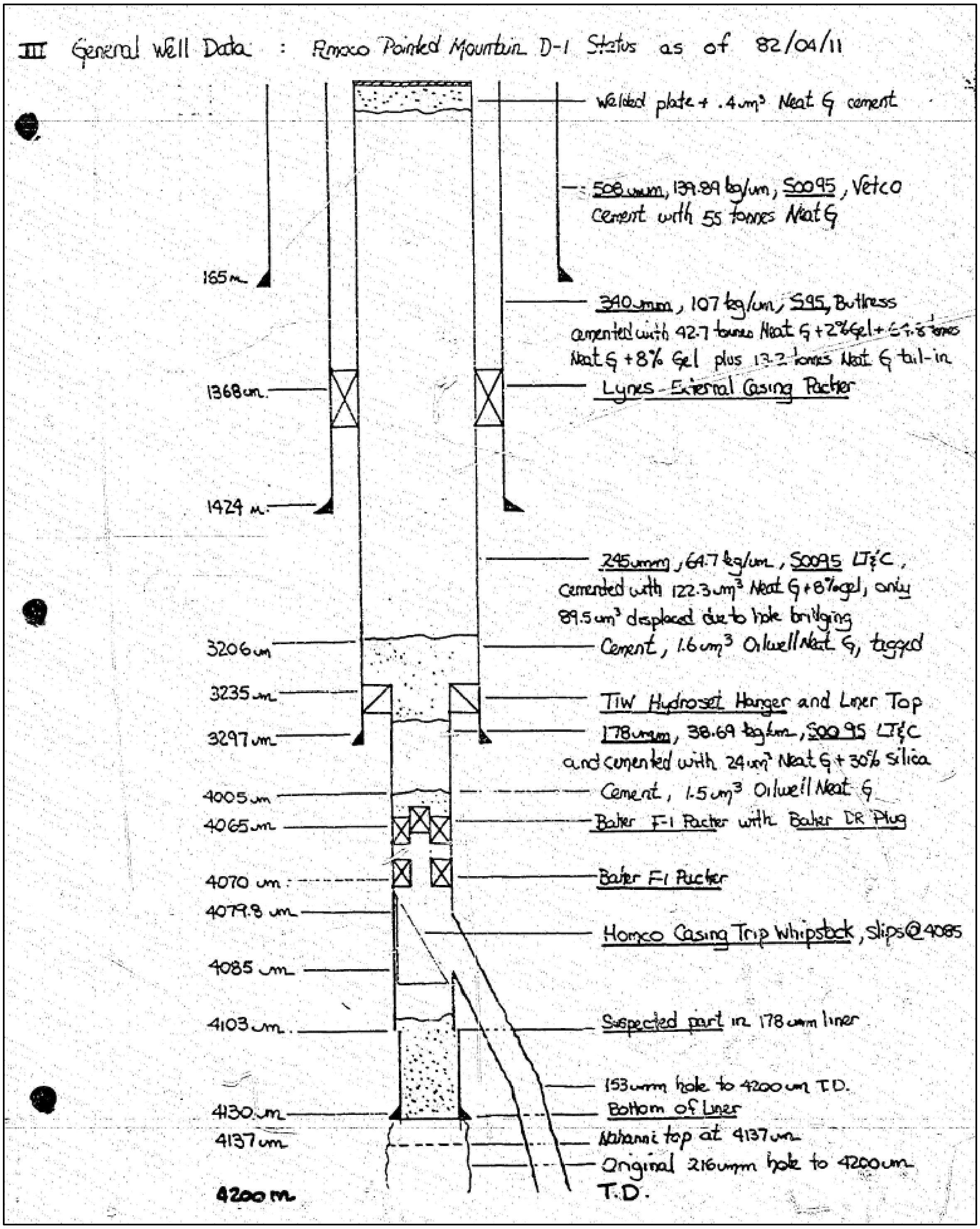

Figure 1 - Wellbore schematic after initial drill, completion and abandonment operations

The well was re-entered in 2011 to perforate, fracture and evaluate the Upper and Lower Muskwa and Exshaw formations. A 114.3 mm ball-drop frac string was run into the liner, with a permanent packer set in the 244.5 mm casing at 3217 mKB. A 139.7 mm tie-back string was installed. The well was left suspended with 114.3 mm retrievable bridge plug set at 3339.0 mKB and the configuration remains the same today. A summary of the re-entry operations is as follows, with detailed reports attached as backup:

Date	**Summary of Re-entry Operations**
2011-08-24	Drive to lease, safety meeting regarding hot-tap, conduct hot-tap, bleed off pressure, monitor well and wait on daylight. Costs inputted include waiting on weather and standby costs for services while gaining access to lease. All new people on location oriented at entryway, workers on standby were oriented at camp.
2011-08-25	Wait on daylight, no flow or pressure at well when arrived on site. Test for LEL's, cut conductor, cut 508mm csg, cut cap. Cement observed, discuss plan with Calgary, install csg bowl and NU BOP's. Leveled area for water tank. Pressure test blind rams, spot rig and rig up same.
2011-08-26	Continued to pressure test 10 K BOP stack components. Crew Change. Held pre-job and safety meeting. Orientated all new personnel and issued safe work permits to new contractors. Completed pressure testing of all components to 1 & 45 MPa on 10K BOP stack. Installed cross-over spool and 50.8 mm single gate rams. Finished rigging up remaining rig equipment. Hauled in and unloaded a total of 431 joints of 88.9 mm, 13.84 kg/m, L-80, tubing. Started building lined water tank and connecting walls. Rigged up snubbing unit above BOP stack. Drill pilot hole in cement plug, no pressure present. Rig down snubbing unit.
2011-08-27	Move in and spotted picker unit. Removed single gate pipe rams and cross-over spool. Crew change. Held pre-job and safety meeting. Made up 215.9 mm Tri-cone Bit and 88.9 mm Drill collar. Rigged up power swivel and pack-off head. Established reverse circulation. Drilled out excess cement at surface left from pilot hole previously drilled. Encountered good torque approximately 1.5 m below casing bowl. Circulated clean and rigged out power swivel and pack-off head. Rigged out rig and moved rig and associated equipment away from well center. Tore down and removed 10K BOP stack. Installed 139.7 mm gate valve and secured well. Moved in track hoe and excavated around wellhead. Wait on people and parts to cut casing bowl.
2011-08-28	Continued to wait on people and parts to arrive. Crew change. Held pre-job and safety meeting. Removed 139.7 mm gate valve and tubing head. Had track hoe finish excavating around wellhead. Welder, wellhead technician, and machined couplings arrived. Cut 339.7 mm surface casing 25 cm below previous welded coupling, removed casing bowl. Install 244.5mm casing extension and weld same. Install 339mm casing collars and casing and install casing bowl to approx. ground level. Jack 244.5mm casing and set slips with 45daN tension. Cut 244.5mm casing, install seal assembly and lift tubing spool into place. Hand tighten studs and wait on construction.
2011-08-29	Continued to wait on construction. Crew change, held pre-job and safety meeting. Back filled hole around wellhead using track hoe and cat. Tightened tubing head onto casing bowl, pressure tested primary and secondary seals to 22 MPa, good test. Installed 70 MPa BOP stack using picker. Spotted rig matting and associated rig equipment. Spotted service rig and rigged up. Rigged up floor and pipe handling equipment. Functioned and pressure tested all components on 70 MPa BOP stack to 1 MPa & 35 MPa, 10 minutes each test. PU bit, 88.9mm collars, install pack-off, drill out cement at surface, trip, remove packoff, torque all

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connections, RIH. Level rig. RIH, obstruction at ~584m. Install power swivel and work through obstruction.

2011-08-30 Continued to drill out cement obstruction tagged at 584 m. Crew change, held pre-job and safety meeting. Picked up another 2 joints and continued to drill down through cement stringers. Ran another 2 joints down without rotating, casing appears cleaned out. Rigged out power swivel and pack-off head. Continued to pick up, tally, drift, and RIH with 88.9 mm, 13.84 kg/m, L-80, tubing. Tag cement at approx. 3204m. LD 1 joint, perform p-test on 9.5/8" csg to 21MPa for 10min. Bleed off, trapped pressure in tubing string. Install CIRC swedge, pressure up, open valve. Reverse CIRC btms up. Run out of suction due to thick fluid left in hole. Wait on vac skid and fluid.

2011-08-31 Continued to wait on fluid and vacuum truck. Crew change. Held pre-job and safety meeting with all personnel on site. Ordered vacuum truck from Ft Nelson (vacuum skid broke down). Note: Towed up 2 water trucks from barge landing last night and 1 water truck this morning. Encountered good rain last night, today sunny and road slowly drying. Hauled in and unloaded 70 m3 of 7% KCL water. Sent 5 water trucks (body jobs) in afternoon down to the barge landing and loaded 90 m3 of fresh water from Ft Liard river. Pump water into 400bbl. Break CIRC, pump returns into 400bbl. Drill cmt plug, pack-off failure. Replace pack-off rubber, drill ahead, CIRC btms up, pack-off failure again. Swap Weatherford pack-off for rig pack-off. Drill cmt plug, power swivel stalling frequently.

2011-09-01 Continued forward circulating, started drilling down. Crew change, held pre-job and safety meeting. Orientated new personnel and issued safe work permit to Troyer vacuum service. Changed back to reverse circulating and circulated bottoms up. Added 8 m3 of clean KCL water to circulating system to help dilute viscous mud in hole. Drilled out approximately 18 m of hard cement down to a total depth of 3240 mKB. Did not tag liner top, estimated liner top within 2 m. Fluid in circulating system more viscous, having trouble pumping. Finished circulating bottoms up and decided to pull out and drill out remaining cement with 158.8 mm bit. Rigged out power swivel and pack-off head, prepared to pull pipe. POOH, pipe not draining. Install mud can and suck with vac truck. Pipe began draining around 2000m, release vac truck, pump 1m3 at 152m to clear pipe (not draining again). Change bit and RIH.

2011-09-02 Continued to run in out of derrick with 88.9 mm tubing. Crew change, held pre-job and safety meeting. Continued running in with 158.8 mm Bit and 88.9 mm Drill collars on 88.9 mm tubing. Ran in out of derrick a total of 154 joints. Landed tubing bottom 9.5 m above previous drilled depth @ 3240 mKB. Picked up 1 joint and rigged up power swivel and RS stripping head. Hauled in 80 m3 of fresh water from the Ft Liard river and spotted tank trucks. Sucked out of tank trucks and reverse circulated to displace mud out of wellbore. Observed golden sand like barite in returns. Started drilling, ran down and cleaned out approximately 7 meters of fill to cement top @ 3240 mKB. Drill from 3240m to 3260m. RIH 2 jts w/o pumping, rig down power swivel and RS head, RIH with 88.9mm tubing.

2011-09-03 Continued to pick up, tally, drift, and run in off pipe racks with 88.9 mm tubing. Crew change, held pre-job and safety meeting with all personnel on site. Ran in a total of 414 joints and tagged plug back @ 3971 mKB. Rigged up power swivel and RS head. Established reverse circulation, could not rotate tubing string, power swivel to small (85 tonne) not enough torque to turn string around bend at this depth. Observed thick mud and good signs of gas in returns. Circulating system more viscous again, lost prime on pump. Continued to circulate gas bubble out using clean KCL water, mud returns less viscous. Rigged out power swivel and RS-head. Pulled out a total of 77 joints, tubing pulling wet, used mud can and vacuum truck. Worked joint # 337 through liner top @ 3235 mKB. Pressure tested the casing to 21 MPa for15 minutes, good test. Continue to POOH, LD BHA, MU logging tools, install lubricator, RIH and log well.

2011-09-04 Continued to bond log well. Crew change, held pre-job and safety meeting with all personnel on site. Conducted GR-CCL-VDL-CBL-Radio log inside 177.8 mm casing from PB at 3961 mKB to top of liner @ 3236 mKB, correlated to an emailed copy of open hole log dated March 25/1982. Cement bond looked good over all zones of interest. Cement bond was questionable over liner top, conducted 7 MPa pressure pass from 3500 m to liner top and improved bond slightly, estimated cement top above liner top behind the 244.5 mm casing. Conducted GR-CCL-VDL-CBL-Radio log inside the 244.5 mm casing from 2950 m to 2000 m. Cement bond looked very poor, conducted 7 MPa pressure pass with no improvement, could not determine cement top. Pulled out and laid down logging tools. RIH and perf 6 intervals as per time log. All charges fired in runs #1-5. Perforated with 127 mm ERHSC, 17 spm, 25 gr salt/pepper, 60° phasing:
3948 – 3953 mKB
3935 – 3940 mKB
3805 – 3810 mKB
3784 – 3789 mKB
3365 – 3370 mKB
3351 – 3356 mKB

2011-09-05 Pulled out and recovered last gun, all shots fired. Rigged out and released wireline unit. Made up and ran in as follows; 155.6 mm Tri-cone Bit, 177.8 mm casing scraper, x-over, 88.9 mm pup joint, 79 joints of 88.9 mm, 13.84 kg/m, L-80, tubing, x-over, 244.5 mm casing scraper, x-over, 88.9 mm pup joint, and 340 joints of 88.9 mm, 13.84 kg/m, L-80, tubing. Worked scraper over all perforated intervals. Tagged hard PB same as before @ 3971 mKB (rig tally). Circulated down and cleaned out approximately 0.5 m of fill, PB was solid. Continued to circulate and displaced well over to 3% KCL water. LD RS head, POOH, LD casing scrapers.

2011-09-06 Continued to pull out with 88.9 mm tubing, racked a total of 328 joints into derrick. Crew change, held pre-job and safety meeting with all personnel on site. Rigged up casing tongs and 114.3 mm handling equipment. Made up, tallied, drifted and ran in with 57 joints of 114.3 mm casing liner and packer assembly. Ran in with weatherford setting tool on 340 joints of 88.9 mm tubing. Set packers, pull test packers, p-test packer top to 21MPa for 15 min. Back-off from packer and POOH laying down 88.9mm tubing.

2011-09-07 Continued to pull out with 88.9 mm tubing, racked a total of 328 joints into derrick. Crew change, held pre-job and safety meeting with all personnel on site. Rigged up casing tongs and 114.3 mm handling equipment. Made up, tallied, drifted and ran in with 57 joints of 114.3 mm casing liner and packer assembly. Ran in with weatherford setting tool on 340 joints of 88.9 mm tubing. Set packers, pull test packers, p-test packer top to 21MPa for 15 min. Back-off from packer and POOH laying down 88.9mm tubing.

2011-09-08 Continued to wait on rig repair to cracked gusset on A-leg frame.

2011-09-09 Repair gusset, test weld with magnetic particles, test is good. Shutdown by NEB.

2011-09-10 Continued to wait on NEB approval to move forward. Conducted CAODC level III inspection on derrick components and documented. NEB approval was granted to continue operations. Held pre-job and safety meeting with all personnel on site. Stood derrick and rigged up rig. Rigged up floor and pipe handling equipment. Made up and ran in with 176.9 mm Ultrapak Latch Seal assembly on 139mm 34.23kg/m P110 LT&C casing. RIH to joint 229, stab into upper packer, mark 20 and 25kdaN compression, back out of packer.

2011-09-11 Continued to wait on NEB approval to move forward. Conducted CAODC level III inspection on derrick components and documented. NEB approval was granted to continue operations. Held pre-job and safety meeting with all personnel on site. Stood derrick and rigged up rig. Rigged up floor and pipe handling equipment. Made up and ran in with 176.9 mm Ultrapak Latch Seal assembly on 139mm 34.23kg/m P110 LT&C casing. RIH to joint 229, stab into upper packer, mark 20 and 25kdaN compression, back out of packer.

2011-09-12 Started up, held pre-job and safety meeting. Rigged out and loaded remaining equipment, cleaned rig tank. Removed 70 MPa BOPS and installed upper 139.7 mm x 70 MPa wellhead. Secured well. Spotted evaporation tank and propane skids. Released water haulers. Total water hauled from Ft Liard river and stored in double lined C-ring tank on location was 6,010 m3. Hauled all rig equipment down to barge landing and prepared to move across river in morning. SDFN.

2011-09-13 Started up, held pre-job and safety meeting. Loaded rig equipment onto barge and moved across river. Loaded rig onto wheeler and moved back to base in Grande Prairie. Hauled rental equipment back to Grande Prairie. Released service rig. Transferred fluid on location to evaporation tank. Wait on frac equipment. Note: Ordered High rate pressure truck and surface gauges to conduct breakdown and feed rate test.

2011-09-14 Wait on availability of Cal-Frac pumping equipment. Assisted NEB on camp and location site inspection.

2011-09-15 Wait on pressure truck to arrive, had tug boat barge across river and unload. Held pre-job and safety meeting. Rigged up pressure truck, installed adapter flange to flow-tee on 70 MPa wellhead. Installed surface recorders. Applied annular pressure. Pumped off tubing end plug and achieved breakdown on Lower Muskwa intervals @ 65.5 MPa. Initial feed rate was 40 lit/min @ 70 MPa, final feed rate was 80 lit/min @ 65.5 MPa. Secured well with surface recorders monitoring pressure every 30 seconds. Rigged out and released pressure truck. Continued to wait on availability for Cal-Frac pumping equipment.

2011-09-16 Continued to wait on Cal-Frac pumping equipment. Surface recorders still monitoring leak off pressure from previous injection test. SITP: 32,280 kPa.

2011-09-17 Continued to wait on availability of Cal-Frac pumping equipment. Surface recorders still monitoring leak off pressure from previous injection test to Lower Muskwa intervals. SITP: 26,200 kPa.

2011-09-18 Continued to wait on availability of Cal-Frac pumping equipment. Scheduled to arrive on Friday Sept 23. Hauled in and spotted sand cans on location, prepared to haul in frac sand next day. Surface recorders still monitoring leak off pressure. SITP was 24,254 kPa.

2011-09-19 Barged 9 transports across river and moved up to location. Unloaded 260 tonnes of sand into sand cans on location. Prepared to move sand transports across river and release units in the morning. Continued to wait on remaining Cal-Frac pumping equipment.

2011-09-20 Hauled in and rigged up transfer pumps and tank manifold to supply water from C-ring tank. Continued to wait on CalFrac pumping equipment.

2011-09-21 Hauled in and rigged up 36.5 m flare stack. Installed ammonia scrubbers to shipping tanks. Continued to wait on availability of Cal-Frac pumping equipment.

2011-09-22 MIRU wellhead isolation tool. Rigged up wind monitoring tower. Continued to wait on Cal-Frac pumping equipment. First wave of equipment to arrive at barge in the morning.

2011-09-23 Barged 15 frac units across river and moved up lease road to camp site. Chained up all equipment and had tow cats assist equipment up access road. Orientated all new personnel.

2011-09-24 Move in remaining CWS units, spot same and rig up to frac. Wait on daylight.

2011-09-25 Rig up to frac. Start transfer pumps from water tank, return line fell from tank edge striking 1 person. See incident report for further details. Review transfer equipment, add additional return line and secure same. Test transfer equipment. Prep to p-test CWS and p-test same. Pump frac treatment as per time long summary. Shut IES isolation equipment, bleed off CWS and rig-down flow lines. Shut-down for daylight.

2011-09-26 Started up, held pre-job and safety meeting with all personnel on site. Staged out wellhead isolation tool. Dropped 84 mm ball onto gate valve. Installed wellhead isolation tool, opened well and dropped ball, staged in isolation tool. Rigged up pumping lines. Pressure tested surface equipment and lines to 83 MPa. Spearheaded 3 m3 of 15% HCL acid + additives. Seated ball and shifted frac sleeve port @ 70 MPa, spotted acid into formation and allowed to soak for 5 minutes. Fracture treated the upper Muskwa intervals down 139.7 mm casing at an average rate of 9 m3/min. Observed breakdown (feed rate) at 70 MPa with an average treating pressure of 69 MPa. Pumped a total of 1,763 m3 fresh water. Down hole sand concentration went from 30 kg/m3 to 220 kg/m3 with sweeps between stages. Total sand pumped was 10 tonne 50/140 mesh, 80 tonne 40/70 mesh and 20 tonne 40/70 prime plus mesh. Total sand into formation was 110 tonne, over flushed by 15 m3. ISIP was 54.7 MPa, 5 min SIP was 52.6 MPa, 15 min SIP was 51.5 MPa. Rigged off pumping lines and secured well for night. SDFN.

2011-09-27 Started up, held pre-job and safety meeting with all personnel on site. Staged out wellhead isolation tool. Dropped 88.9 mm ball onto gate valve. Installed wellhead isolation tool, opened well and dropped ball, staged in isolation tool. Rigged up pumping lines. Pressure tested surface equipment and lines to 83 MPa. Spearheaded 4 m3 of 15% HCL acid + additives. Seated ball and shifted frac sleeve port @ 75 MPa, had difficulty shifting sleeve, spotted acid into formation and allowed to soak for 5 minutes. Fracture treated the upper Exshaw intervals down 139.7 mm casing at an average rate of 3.6 m3/min. Observed no breakdown, very tight, started to feed at 65 MPa with a lower rate initially. Average treating pressure was 72 MPa. Pumped a total of 871 m3 fresh water. Down hole sand concentration was between 30 kg/m3 to 70 kg/m3 with sweep stages. Total sand pumped was 10 tonne 50/140 mesh and 17 tonne 40/70 mesh. Total sand into formation was approximately 26 tonne. Sanded off with approximately 1 tonne inside pipe, total flush volume was 9.5 m3. ISIP was 75 MPa, 5 min

SIP was 55.8 MPa. Rigged off pumping lines, rigged out wellhead isolation tool. SITP: 48,170 kPa; SICP: 10,220 kPa. Opened well up and flowed back to P-tank through 7.9 mm bean choke. Made straight fluid, no sign of any gas, returns slightly foamy, average recovery rate was 40 m3/hr. Water salinity was 14,000 ppm, temperature was 124 deg C, no sign of any sand. After 8 hours of continuous flowing the tubing pressure was down to 28,870 kPa, total fluid recovered was 324 m3. See testers field notes for all details. Continued to flow well back on clean up.

2011-09-28 Continued to flow back well on clean up. Held pre-job and safety meeting. Rigged out Cal-frac pumping equipment. Moved mostly all of Cal-Frac equipment off location. Chained up equipment and had tow tractors assist equipment down access road back to camp. Continued to flow well back to P-tank up 139.7 mm casing. Observed first signs of burnable gas after 15 hours of flowing and approximately 20% load fluid recovered. Gradually increased choke size until flowing wide open through gutline. Average fluid recovery rate gradually decreased to 15.5 m3/hr. After 32 hours of continuous flowing the tubing pressure gradually declined to 830 kPa. Well appeared to be slowly loading up. Estimated gas rate between 2,000 - 3,000 m3/d, no sign of any H2S, tested approximately 15% CO2. No sign of any more sand in returns. Total load fluid recovered was 1,031 m3 water, load fluid left to recover was approximately 2,837 m3. Final water salinity was 30,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well back on clean up.

2011-09-29 Continued to flow well back to P-tank up 139.7 mm casing. Moved remaining frac equipment off location, emptied sand cans and prepared to move. Flowed back wide open through 50.8 mm gutline. Pressure and rates gradually declined. Well appears to be slowly dying off and loading up, but still pushing fluid. Average fluid recovery rate decreased to 7.5 m3/hr, no sign of any sand. After 56 hours flowing tubing pressure (139.7 mm csg) declined to 800 kPa, estimated gas rate around 2,000 m3/d. No sign of any H2S, tested 15% CO2, flow temperature at 39 deg C. Total load fluid recovered to date was 1,327 m3 water, load fluid left to recover was approximately 2,541 m3. Water salinity was 28,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well until dead.

2011-09-30 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Well appears to be slowly dying off and loading up, but still pushing fluid. Average fluid recovery rate decreased to 6.5 m3/hr, no sign of any sand. After 80 hours flowing tubing pressure (139.7 mm csg) appeared stable between 650 to 700 kPa, estimated gas rate between 2,000 to 3,000 m3/d. No sign of any H2S, tested 15% CO2, flow temperature at 32 deg C. Total load fluid recovered to date was 1,488 m3 water, load fluid left to recover was approximately 2,380 m3. Water salinity was 30,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well on clean up.

2011-10-01 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Well appears to be slowly dying off and loading up, but still pushing fluid. Shut in well for 1 hour 3 times and monitored build up pressure. SITP increased to 9,700 kPa twice and 8,940 kPa on the third time. Pressure bled off immediately each time well was opened, very little gas head, all fluid pressure. Average fluid recovery rate decreased to 3.5 m3/hr, no sign of any sand. After 104 hours flowing tubing pressure (139.7 mm csg) would flux between 570 to 650 kPa, estimated gas rate at 2,000 m3/d or less. Unable to get accurate gas rate because meter too big to measure small rates, smaller meter to arrive and install today. No sign of any H2S, tested 15% CO2, flow temperature at 30 deg C. Total load fluid recovered to date was 1,575 m3 water, load fluid left to recover was approximately 2,293 m3.

Water salinity was 40,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well on clean up.

2011-10-02 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Average fluid recovery rate was 3.5 m3/hr, flowing tubing pressure (139.7 mm csg) was 650 kPa. No sign of any H2S, tested 15% CO2, flow temperature at 32 deg C. Shut in well for 4 hours. Removed ball catcher from wellhead and retrieved 88.9 mm ball stuck inside catcher. Rigged up flowline back to wellhead, installed smaller meter before outlet to flare stack. SITP was 11,250 kPa. Flowed back to P-tank wide open through 50.8 mm gutline. Pressure bled off immediately, observed small gas head followed by straight fluid. Pressure decreased to 100 kPa, no sign of any more gas, average fluid recovery rate increased to 6.4 m3/hr last 4 hours. Shut in well and monitored pressure build up overnight. Flowed well for a total of 106 hours. Total load fluid recovered to date was 1,611 m3 water, load water left to recover was approximately 2,257 m3. Water salinity was 39,000 ppm, PH was 7. SIWP after 13 hrs was 13,800 kPa. See testers field notes for all details. Continued to monitor build up pressure.

2011-10-03 Continued to monitor build up pressure. After 26 hours SIWP was 15,470 kPa. Rigged out and released 36.5 m flare stack. Rigged up 12.2 m flare stack. Collected 2 gas samples. Opened well up and flowed back to P-tank through 50.8 mm gutline. Pressure bled down immediately to 800 kPa, observed very small gas head then started making straight fluid. Flowing pressure would flux between 300 to 600 kPa, average fluid recovery rate was approximately 6.4 m3/hr. No sign of any gas. Total fluid recovered last 11 hours was 69.9 m3. Total fluid recovered to date was 1,680.6 m3 water, load water left to recover was approximately 2,187.4 m3. Water salinity was 36,000 ppm, flow temperature was 18 deg C. See testers field notes for all details. Continued to flow well back on clean up.

2011-10-04 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Well was still pushing fluid, average fluid recovery rate last 6 hours was 3.8 m3/hr, no sign of any sand. After 35 hours of continuous flowing, the tubing pressure (139.7 mm csg) appeared stable around 410 kPa, estimated gas rate just below 1,000 m3/d. No sign of any H2S, tested 15% CO2, flow temperature at 18 deg C. Total load fluid recovered to date was 1,798 m3 water, load fluid left to recover was approximately 2,070 m3. Water salinity was 48,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well on clean up.

2011-10-05 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Well was still pushing fluid, very little gas again, average fluid recovery rate was 3.5 m3/hr, no sign of any sand. After 59 hours of continuous flowing, the tubing pressure (139.7 mm csg) would flux between 100 to 300 kPa, estimated gas rate just below 1,000 m3/d. No sign of any H2S, tested 15% CO2. The well stopped making gas last 8 hours, used propane to ship fluid. Flow temperature at 18 deg C. Total load fluid recovered to date was 1,882.6 m3 water, load fluid left to recover was approximately 1,985.4 m3. Water salinity was 44,000 ppm, PH was 7. See testers field notes for all details. Continued flowing well on clean up.

2011-10-06 Continued to flow well back to P-tank up 139.7 mm casing. Flowed back wide open through 50.8 mm gutline. Well appears to be slowly dying off and loading up, but still pushing fluid. Presently no sign of any gas (comes & goes). Average fluid recovery rate decreased to 2.7 m3/hr, no sign of any sand. After 70.5 hours flowing tubing pressure was around 450 kPa. Last estimated gas rate was below 1,000 m3/d, no sign of any H2S, tested 15% CO2. Final flow temperature was at 20 deg C. Total load fluid recovered to date was 1,914 m3 water, load fluid left to recover was approximately 1,954 m3. Water salinity was 44,000 ppm, PH was 7. See testers field notes for all details. Shut in well and rigged up electric wireline unit. Installed lubricator with grease injector head. Ran in with 70 mm gauge ring and tagged possible frac ball at 2350 m, chased ball down to bottom and tagged frac sleeve port @ 3811 m. Pulled out with gauge ring and rigged off lubricator. Continued to monitor build up pressures. SIWP after 11.5 hours was 10,100 kPa. Opened well up and flowed back to P-tank through 50.8 mm gutline. Pressure bled down rapidly and started making straight fluid, very little signs of gas. Recovered 7.7 m3 load water in first hour. Continued to flow well and prepared for spinner log.

2011-10-07 Continued to flow up 139.7 mm casing back to P-tank wide open through 50.8 mm gutline. Flowing straight fluid around 200 kPa, very little signs of gas, average fluid recovery rate last 3 hrs was 5 m3/hr. Held pre-job and safety meeting. Rigged up wireline lubricator with grease injector head. Continued flowing well and ran in with production-spinner log. Ran down through both frac sleeve ports to a total depth of 3850 mKB, no sign of missing shifting sleeve ball. Correlated on depth to Encore Radial Cement Bond Log dated Sept 4/2011. Conducted 3 up and 3 down passes at 30, 20, and 10 m/min from 3850 m to 3250 m. Started to see more gas at surface while logging, measured gas rate at 0.4 m3/d. Made 10 minute station stops at 3835, 3775, 3380, and 3340 mKB. Collected 2 gas samples prior to shutting in well. Total load water recovered was 1,953 m3. See testers report for details. Made 3 shut in passes at 30, 60, and 90 minute intervals at 20 m/min from 3850 m to 3250 m. Pulled out with logging tools. Rigged out grease injector and lubricator with BOPS. Rigged out wireline unit and moved equipment back to camp. Prepared to barge across river in the morning. Moved in and rigged up High rate pressure truck, held prejob and safety meeting. Started to inject load water back into wellbore. Initial pumping rate was 0.5 m3/min @ 30 MPa. Final pumping rate was 0.5 m3/min @ 48 MPa. Stopped pumping to cool down unit and tighten leak on flange.

2011-10-08 Continued to suck out of C-ring tank and pump load water down wellbore at an average pumping rate of 0.4 m3/min @ 48 MPa. Injection pressure remained stable last 20 hours. Total pumping time was 33 hours including cool down and maintenance breaks. Estimated total volume pumped was 620 m3. Continued to dispose load water down wellbore.

2011-10-09 Pressure truck shut down due to diesel pollution control for exhaust, urea pod was empty. Wait on hot shot from Ft Nelson with more urea. Continued to suck out of C-ring tank and pump load water down wellbore at an average pumping rate of 0.4 m3/min @ 49 MPa. Injection pressure remained fairly stable. Total pumping time was 48 hours including cool down and maintenance breaks. Estimated total volume pumped was 900 m3. Continued to dispose load water down wellbore.

2011-10-10 Continued to suck out of C-ring tank and pump load water down wellbore at an average pumping rate of 0.4 m3/min @ 49 MPa. Injection pressure remained stable last 33 hours. Total pumping time was 72 hours including cool down and maintenance breaks. Estimated total volume pumped was 1400 m3. Continued to dispose load water down wellbore.

2011-10-11 Continued to suck out of C-ring tank and pump load water down wellbore. Sucked out C-ring tank mostly dry for a total of 1,420 m3 disposed down wellbore. Rigged out pressure truck and moved over to suck out of tank farm. Started to pump from tank farm when pressure truck broke down due to clutch failure, could not continue. Rigged out pressure truck and lines. Towed pressure truck down to barge landing for morning. Secured well. Note: Backup pressure truck still not available, on waiting list with several contractors. Attempt to line up tank trucks to transfer remaining fluid, approximate load water left on location is 530 m3. SDFN.

2011-10-12 Barged picker and tractor trailers across river to assist in tear down of C-ring tank. Access road very wet and muddy, very slippery at barge landing. Tow tractors had to assist all equipment up to camp, took all day to get equipment that far, road condition bad. Has been wet fog and light rain/snow last several days. Wait on availability of high rate 10K pressure truck, initial truck possibly has clutch repaired tomorrow.

2011-10-13 Towed picker and trucks up to location from camp. Dismantled and loaded C-ring tank along with liner for disposal. Towed equipment back to camp. Access road very wet and muddy, used both tow tractors on each end of units to assist in and off location, very slippery conditions.

2011-10-14 Towed bed truck trailers down to barge landing with heavy loads (c-ring walls & liner debris). Access road in poor condition at sections, tow tractor and bed truck both stuck, wait on cat to assist equipment free. Had to repair chains on one tow tractor. Loaded trucks onto barge, Tiggo picker still at camp waiting for tow. Towed wireline unit and picker from barge landing up to camp. Wireline unit broke down, tore fan belt off, have no power to computer end. Replace fan belt and check fuses in morning and attempt to fix electrical problem. Note: Access road from camp to location site starting to dry and improve.
Note: Ordered 2 commanders with 24 hr crews for Monday Oct 17 to start demobilization of camp. Will also use another commander previously here for Apache.

2011-10-15 Worked on wireline truck. Replaced fan belt and repaired electrical problem. Moved Boreal electric wireline unit from camp to location site. Access road was frozen early morning, equipment moved in chained up with no problems. Held pre-job and safety meeting. Rigged up wireline unit with picker. Installed lubricator with grease injector head, pressure tested lubricator. SIWP: 26,000 kPa. Ran in with 94 mm gauge ring to just above the Exshaw intervals. Ran in with Tryton 10K WR plug, correlated to Boreal Production-Spinner Log dated October 7/2011. Set Retrievable Bridge Plug inside the 114.3 mm Liner 12 m above the Exshaw intervals @ 3339 mKB. Pulled out and recovered setting tools. Rigged out and released wireline unit. Bled well pressure off back to P-tank, pressure bled off quickly and recovered minimum fluid, well was dead, plug was holding. Ran hose down tubing and had vacuum truck suck down fluid level. Pour 160 liters of weighted corrosion inhibitor down tubing for approximately 0.5% inhibited volume. Shut in and secured well. Rigged out remaining test equipment. Rigged out all remaining rental equipment. Prepared to move equipment in the morning. SDFN.

2011-10-16 Had tow tractors assist wireline equipment and testers down to barge landing. Loaded barges and transported equipment across river and released. Hauled evaporation tank and wellsite shack down to barge landing. Hauled all remaining equipment including P-tank off location and down to camp site. Left 12 rental tanks with approximately 530 m3 load water on location. Cleaned up location site and secured well. Note: Sent 4 gas samples to AGAT in Ft St John for routine analysis.

2011-10-17 Barged 2 commander units across river. Started to dismantle camp. Emptied water tanks and sucked out sewer tank. Tore down water lines and sewer lines. Pulled all pumps from water wells. Released camp staff and moved all other necessary personnel over to base camp on other side of river. Started hauling camp and equipment down to barge landing. Total of 3 commander units hauling 24 hr/d.

2011-10-18 Continue to load and haul camp and equipment down to barge landing using commanders to travel access road. Had 1 bed truck working camp site and another bed truck loading barges. Encountered rain again, access road soft and muddy, tow tractors had to assist commanders through bad section. Had cats continue to work section of road. The smaller commander unit broke down, could not repair drive shaft, continued hauling with remaining commanders. Approximately 60% of camp and equipment hauled down to barge landing with approximately 40% across river.

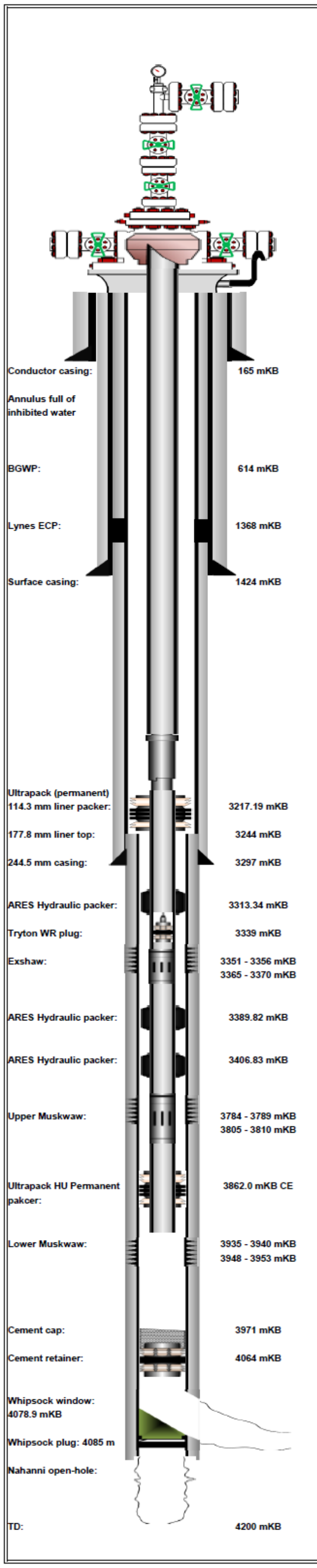
2011-10-19 Continued to load and haul camp and equipment down to barge landing using commanders. Had cat and grader smooth out location site and access road down to camp site. Remaining cats worked bad section on access road to barge landing to help keep equipment moving. Road getting better. Continued barging equipment and shacks across river. Had bed trucks haul camp shacks to Acho camps yard near Ft Liard. Hauled and set up camps wellsite unit at main base camp in Ft Liard. Hauled P-tank and pipe skid to Ft St John. Hauled 10K rental pipe and manifold to Grande Prairie. Approximately 90% of camp and equipment hauled down to barge landing with approximately 70% across river. Continued with camp clean up and road repair.

2011-10-20 Continued to haul final loads down to barge landing. Cleaned up camp site. Loaded barges and transported all remaining camp and equipment across river. Transported bed trucks and commanders across river. Hauled and returned all camp shacks back to Acho yard near Ft Liard. Load and release commanders in the morning. Note: Left construction equipment on other side of river to clean up access road.

2011-10-21 Had cats and grader work access road and smooth all ruts out. Moved all construction equipment down to barge landing and prepared to transport across river in the morning. Started loading and hauling out all rental equipment.

2011-10-22 Cleaned up barge landing site and restored to original condition. Loaded all construction equipment and barged across river. Loaded and returned all rental equipment back to origins in Edmonton, Red Deer, Grande Prairie, Ft St John, and Ft Nelson. Access road left in fair condition with no bad ruts. Well secured. Left 12 rental tanks with approximately 530 m3 water equally balanced between all tanks on location to freeze over winter. Job completed.

Note: Beaver Enterprises will tear up and load liner material into Kris Muller's end dumps and haul to Secure in Grande Prairie for disposal.



WELLBORE PROFILE

Prairie Provident Resources Canada Ltd.

S. Pointed Mountain (D-1) L-68

UWI:	300/L-68-60-20-123-45/1	Licence:	1207	Date:	April 29, 2021
Surface:		Deviation:	Deviated	AFE / Job #:	

ELEVATIONS & DEPTHS (m)

TMD	4200.00	KB ELEV	737.00	KB TO SCF	
TVD	4139.86	GL ELEV	723.00	KB TO THF	4.70
PBTD	3971.00	KB - GL	14.00	Well Status	Suspended

CASING DESCRIPTION & GRADE	OD (mm)	WEIGHT (kg/m)	TOP LOCATION	LANDED DEPTH (m)
Conductor Casing: SOO-95, LT&C	508.0	139.9	Surface	165.00
Surface Casing: SOO-95, LT&C	339.7	107.2	Surface	1424.00
Production Casing: SOO-95, LT&C	244.5	64.7	Surface	3297.00
Liner: SOO-95, LT&C	177.8	38.7	3244	4130.00
Tie-back: P-110, LT&C	139.7	34.2	Surface	3217.20

Perf Date	Zones	Top Shot	Bottom Shot	Status	Gun Data
5-Sep-11	Exshaw	3351.00	3356.00	Suspended	17 SPM, 25 gr, 60°
5-Sep-11	Exshaw	3365.00	3370.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3784.00	3789.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3805.00	3810.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3935.00	3940.00	Suspended	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3948.00	3953.00	Suspended	17 SPM, 25 gr, 60°
12-Oct-82	Nahanni	4079.80	4200.00	Abandoned	Whip-stock, open-hole
13-Sep-82	Nahanni	4130.00	4200.00	Abandoned	Open-hole

DOWNHOLE DESCRIPTION FROM BOTTOM UP (Tubing String)

QUANTITY	DESCRIPTION	LENGTH (m)	TOP OF (mKB)
1	125 mm pump out shoe (28.7 MPa shear)	0.25	3900.06
2	3 - 114.3 mm, 22.47 kg/m, P-110 casing joints	34.25	3865.81
3	114.3 mm pup joint	2.76	3863.05
4	149 mm Weatherford Ultrapak HU hydraulic set permanent packer	3.40	3859.65
5	4 - 114.3 mm, 22.47 kg/m, P-110 casing joints	46.19	3813.46
6	139.7 mm Weatherford frac sleeve port (84 mm ball seat)	1.23	3812.23
7	35 - 114.3 mm, 22.47 kg/m, P-110 casing joints	403.64	3408.59
8	147.3 mm ARES Hydraulic set open-hole packer	3.60	3404.99
9	1 - 114.3 mm, 22.47 kg/m, P-110 casing joint	11.55	3393.44
10	114.3 mm pup joint	1.86	3391.58
11	147.3 mm ARES Hydraulic set open-hole packer	3.60	3387.98
12	1 - 114.3 mm, 22.47 kg/m, P-110 casing joint	11.35	3376.63
13	114.3 mm pup joint	3.07	3373.56
14	139.7 mm Weatherford frac sleeve port (89.2 mm ball seat)	1.23	3372.33
15	5 - 114.3 mm, 22.47 kg/m, P-110 casing joints	57.23	3315.10
16	147.3 mm ARES Hydraulic set open-hole packer	3.60	3311.50
17	8 - 114.3 mm, 22.47 kg/m, P-110 casing joints	91.85	3219.65
18	219.1 mm Ultrapack Liner Top Packer	1.40	3218.25
19	176.9 mm Ultrapack Latch Seal Assembly	0.76	3217.49
20	229 - 139.7 mm, 34.23 kg/m, P-110, LT&C joints (frac string)	3193.10	24.39
21	1 - 139.7 mm pup joint	4.94	19.45
22	1 - 139.7 mm casing joint	13.85	5.60
23	279.4 x 139.7 mm tubing hanger	0.30	5.30
			-
	SITP before setting 114.3 mm bridge plug: 26,000 kPa		-
		0.45	4.85
		0.15	4.70
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WEIGHT OF TUBING STRING (daN)		TOTAL STRING LENGTH	3895.61
TENSION/COMPRESSION (+/- daN)		STRETCH/SLACKOFF (+/- m)	
LANDED STRING WEIGHT (daN)	-	TUBING BOTTOM (mKB)	3900.31

WELLHEAD DESCRIPTION

ITEM #	DESCRIPTION	SERIAL #	MWP (MPa)	SIZE (mm)
	Casing Bowl		35.0	346 x 339.7
	Upper flowing style wellhead		69.0	279.4 x 139.7

ABANDONMENT SPECIFICS

ZONES	SCVF / GM	LOW CEMENT	REMEDIAL	TUBING (Y/N)	RODS (Y/N)
1	Yes	N	N	Y	N

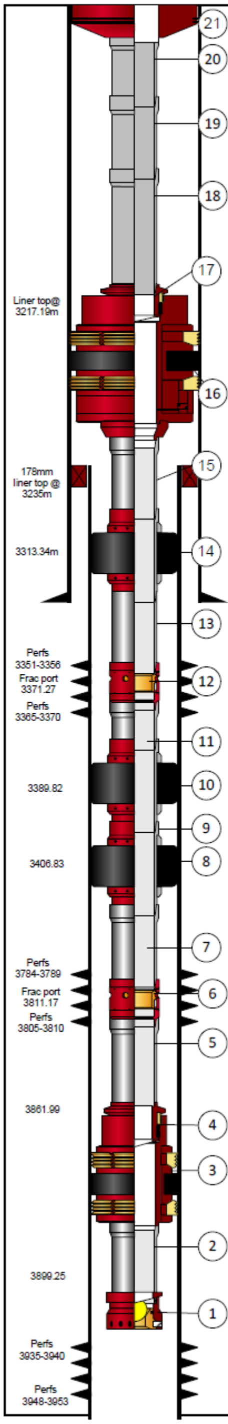
REMARKS

Prepared by: Jonah Urton

Figure 2 - Well diagram after 2011 re-entry

Weatherford®

Large Bore Multi-Zone Frac Assembly



Final Installation Report

Company	Canadian Forest Oil			Reference	ZS11231 - B
Prepared for	Dana Roney	Phone	403-292-8049	Location	L-68-60-20-123-45
Prepared by	Dan Johnson	Sales Rep	Randal B.		
Service Centre	Edmonton Liner 1-866-844-0316	Drawn by	Dan Johnson	Date	7-Aug-2011 Page 1

TUBULAR	Size (mm)	Weight (kg/m)	Grade	Thread	Depth
Casing	244.5	64.7	SOO-95	LT&C	3235
Liner 1	177.8	38.69	SOO-95	LT&C	4130
Liner 2	114.3	22.47	P-110	LT&C	3899.25
Tubing 1	139.7	34.23	P110	LT&C	3217.19

ITEM	DESCRIPTION	I.D. (mm)	O.D. (mm)	Length (m)
1.	High Pressure Pump Out Ball Seat	101.6	127	0.25
2.	3 joints 114.3mm Liner Casing	97.2	114.3	34.25
3.	Ultrapak HU Series, Hydraulic Set Permanent Packer w/ Large Upper (120.65mm) Seal Bore, includes 1.24m pup below	99	149	2.76
4.	Ultrapak Series Latch Seal Assembly. Minimum ID: 98.425mm (3..875") includes 3.08m pup on top	98.4	149	3.40
5.	4 joints 114.3mm Liner Casing	97.2	114.3	46.19
6.	ZS Series Single Shot, Ball Actuated, Frac-Through Sleeve. Seat Size: 79.76mm (3.14"), Ball Size: 84.07mm (3.310")	101.6	139.7	1.23
7.	35 joints 114.3mm Liner Casing	97.2	114.3	403.64
8.	13.5# ARES Two Stage Hydraulic Set Packer w/ Top Handling Pup	99.6	147.3	3.60
9.	1 joint, 1 pup joint 114.3mm Liner Casing	97.2	114.3	13.41
10.	13.5# ARES Two Stage Hydraulic Set Packer w/ Top Handling Pup	99.6	147.3	3.60
11.	1 joint, 1 pup joint 114.3mm Liner Casing	97.2	114.3	14.42
12.	ZS Series Single Shot, Ball Actuated, Frac-Through Sleeve. Seat Size: 84.71mm (3.34"), Ball Size: 89.03mm (3.51")	101.6	139.7	1.23
13.	5 joints 114.3mm Liner Casing	97.2	114.3	57.23
14.	13.5# ARES Two Stage Hydraulic Set Packer w/ Top Handling Pup	99.6	147.3	3.60
15.	8 joints 114.3mm Liner Casing	97.2	114.3	91.85
16.	Ultrapack Series High Pressure Rated (8,000psi), Permanent Liner Top Packer c/w 120.65mm (4.75") Seal Bore w/ Latch Profile.	99.6	210	1.40
17.	Ultrapak Series Latch Seal Assembly. Minimum ID: 98.425mm (3.875"), NEOS Seals	99	177	0.28
18.	227 Joints of 139.7mm Casing	118.62	139.70	3193.1
19.	(2) 139.7mm Pups(1.87m, 3.07m)	118.62	139.70	4.94
20.	Joint #228 of Casing w/o collar	118.62	139.70	13.85
21.	Tubing Hanger	139.70		0.28
22.	KB to THF			13.00
23.	Compression			-.75
24.	Tubing Correction			-7.51

NOTES

KB difference 9.00m
Tubing tally correction -8.00m
Top of ARES packer assemblies to center of element 2.90m
Down weight of string is 90000daN and up weight is 92000daN
5000daN confirmation pull over
23000daN compression on packer

Figure 3 - Detailed frac string schematic

Procedure:

Boreal E-Line – a division of Bonnett's Energy Corp., rigged in the hole on October 7th, 2011 with a Production Logging tool string with GR/CCL, Pressure, Temperature and spinner sensors. Three down passes and three up passes at 20, 30, 40 m/min cable speed were recorded from 3250 mKB to 3852 mKB under flowing condition. Then the well was shut in and three shut in passes (30/60/90 minute) were done from 3250 mKB to 3852 mKB. A list of the files acquired is:

Oct 7, 2011	Interval	Direction	Line Speed	Pressure(kPa)	Gas Prod (E^3m^3/d)
Flowing	3250 – 3852 mKB	Down	10 m/min	324	1.18
Flowing	3250 – 3852 mKB	Up	10 m/min	324	1.18
Flowing	3250 – 3852 mKB	Down	20 m/min	412	0.48
Flowing	3250 – 3852 mKB	Up	20 m/min	412	0.48
Flowing	3250 – 3852 mKB	Down	30 m/min	256	0.41
Flowing	3250 – 3852 mKB	Up	30 m/min	256	0.41
Shut-In	3250 – 3852 mKB	Down	20 m/min		0
Shut-In	3250 – 3852 mKB	Down	20 m/min		0
Shut-In	3250 – 3852 mKB	Down	20 m/min		0

Results:

Production:
From the surface data, the production is gas (1.18E^3m^3/d) with water (1.6 m^3/d) on October 7, 2011.

Frac Port	Perforations/Frac Ports (mKB)	Fluid	Gas Contribution	Gas Prod. E^3m^3/d	Cum Gas Prod. E^3m^3/d
1	3351.0 – 3356.0	No Apparent	0%	0.0	0.0
1	3365.0 – 3370.0	Gas	17%	0.20	1.18
2	3784.0 – 3789.0 3805.0 – 3810.0	Gas	83%	0.98	0.98
3	3935.0 – 3940.0 3945.0 – 3953.0	No Apparent	0%	0.0	0.0

From the spinner response (both down passes and station stops) it appears there is inflow from the frac ports #1 & #2; most of the response is from the second frac port at 3811.17mKB (perforations at 3805.0 – 3810.0 mKB & 3784.0 – 3789.0 mKB). From the spinner response of down pass at 10m/min cable speed, it is calculated that around 83% of production is coming from the second frac port (3805.0 – 3810.0 mKB & 3784.0 – 3789.0 mKB), the rest of 17% of production is coming from the top frac port (3365.0 – 3370.0 mKB). The spinner response at station stop 3825.0 mKB is 0 rps, indicating that there is no inflow from the lower perforation intervals 3935.0 – 3940.0 mKB & 3945.0 – 3953.0 mKB

From the cooling traces across the perforations zones, it appears that a large amount of gas is coming from the two perforations at 3805.0 – 3810.0 mKB & 3784.0 – 3789.0 mKB (large cooling effect across the zones). The temperature data shows slightly cooling effect over the perforation interval (3365.0 – 3370.0 mKB), indicating gas is entering into wellbore from this perforation interval; temperature data does not show any cooling effect at perforation interval (3351.0 – 3356.0 mKB) which would mean no gas is entering into wellbore from perforation interval 3351.0 – 3356.0 mKB.

CDN Forest S. Pointed Mountain L-68 - PL report

Figure 4 - Spinner log notes – Boreal Eline Oct 7, 2011

3 Abandonment Program – Recommended Procedure

Refer to Vertex Professional Service standard procedure, "Fire and Explosion Prevention" regarding Directive 33.

3.1 Wellbore Abandonment

Note: Copy of Operations Authorization, Well approval and operating manuals and other procedures to execute the work activity should be available all the time in the location

- All depths in the program are measured depths.
- "Oil and Gas Occupational Health and Safety Regulations", "Oil and Gas Drilling and Production Regulations" and "Oil and Gas Operations Act" Copies should be followed and available on site all the time.
- Personnel and equipment certificates should always be available during operations.

2. Notify the PPR field office and OROGO at least 24 hours before commencing well site operations. Ensure the following documentation is completed prior to commencing wellsite operations:
   - PPR Wellsite Hazard Assessment Plot Plan; scout the location for construction requirements, hazard identification, and wellhead specification.
   - PPR Notice of Supervision form.
   - PPR Well Site / Facility Handover Form with the PPR production staff.
   - PPR 'Ground Disturbance' requirements.
   - PPR Flaring / Venting / Incinerating Resident Notification Form; deliver to all the applicable residents and document the date and time of delivery in daily report - confirm with the Calgary office that the resident notification has been conducted.
     i. Note: Refer to the key contacts in the program for names and numbers.
3. No flaring is anticipated on this wellbore.
4. Perform a surface casing vent flow and gas migration test. Ensure the PPR Surface Casing Vent Flow/Gas Migration Data Sheet is completed and sent in with the final report.
5. Rig in free standing Class III rig and associated equipment in accordance with which OROGO, PPR Exploration and OH&S specifications. Complete CAODC service rig inspection and rectify any deficiencies before continuing. Function test crown saver and all diesel engine kills.
   - Note: Ensure the Unit and associated equipment can handle 73.0 mm / 60.3 mm tapered work string, and 3200 m of 139.7 mm tie-back string

6. Rig in the following safety services as required:

Service	**Condition**
ETV	Travel time from wellsite to health care facility > 40 min
Medic	Number of workers on location > 19
Air Trailer	H2S > 0 ppm
Safety Supervisor	H2S > 1.0%
Fire Protection	Heating or high pressure pumping of flammable fluids
Shower unit	Potential of body exposure to injurious materials

7. Sweep area for 'LELs'. Check wellhead for H2S and shut-in pressures.

8. Hold a safety and procedural meeting; conduct a pre-job hazard assessment with all onsite personnel and document in the daily report.
   - Note: Ensure the Directive 033 - Explosive Mixture and Ignition Potential Identification Sheet is filled out, discussed, and posted in the doghouse.

9. Stump test the BOP equipment, manifold, and lines. Ensure the well is dead; kill well by circulating well over to fresh water. Remove wellhead, install the BOPs and pressure test the ring groove connection. Perform all pressure and function tests.
   - Note: Low pressure test: 1400 kPa. High pressure test: 21 000 kPa (Or Max. capability of wellhead)
   - Note: water will be used as a kill fluid since Hydrostatic Pressure of water @ deepest existing open perforation is higher than the determined BHP @ that depth. Please see below calculations:

   Data: BHP = 40 MPa

   H (top of open-hole section): 3351 mKB

   Hydrostatic Pressure of water @ top of open hole. = 9.81 kPa/m * 3351 = 32.87 MPa

   Therefore water as a kill fluid will be enough to suppress the pressure of formation fluids

10. Run in hole with Tryton "WR" retrieving tool on 60.3 mm / 73.0 mm tapered tubing string. Latch on to plug and open equalizing valve. Unset "WR" plug at 3339 mKB and let elements relax for 10 minutes. Pull and stand tapered tubing string. Lay down "WR" plug.

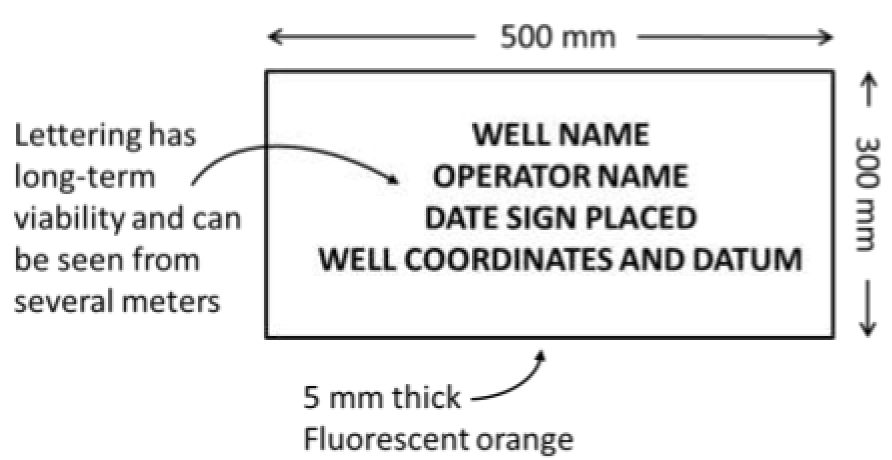
11. Conduct injectivity test in to the Exshaw, Upper and Lower Muskwa perforations with at least 2.0 m3 of fresh water. Design a cementing program based on the injectivity test results. Record the ISIP and monitor SCVF during injection.

12. Run recommended Weatherford 5-Blade Mill to tag ball seat in frac sleeve at 3372.33 mKB. Rig in power swivel and mill through ball sleeve. Continue to mill through second frac sleeve at 3812.23 mKB. Circulate clean, pull and lay down milling equipment.
13. Rig up wireline unit with pressure tested lubricator, run gauge ring to approximately 3900 mKB and retrieve.
14. Run and set cement retainer above lower frac sleeve at ~3775 mKB.
15. Run cement stinger on tapered work string, sting into cement retainer (cementing program pending injection test results).
    - Move in C&A unit, bulker and vacuum truck. Conduct slow rate cement squeeze through the cement retainer in to the Muskwa perforations.
        i. The cement volume squeezed must be at least equal to the casing volume from the bottom of the retainer to the bottom perforations plus 0.5 m3.
        ii. The final squeeze pressure must be a minimum of 7 MPa above the current reservoir pressure of the Muskwa.
16. Sting out of retainer and balance a 30 m cement cap on the retainer. Pull and stand tapered tubing string.
17. Conduct secondary injectivity test into Exshaw perforations while monitoring SCVF. Document ISIP.
18. Rig up wireline unit, run and set second cement retainer above upper frac sleeve at ~3340 mKB. Pressure test to 7000 kPa for 10 minutes.
19. Run cement stinger on tapered work string, sting into cement retainer (cementing program pending injection test results).
    - Move in C&A unit, bulker and vacuum truck. Conduct slow rate cement squeeze through the cement retainer in to the Exshaw perforations.
        i. The cement volume squeezed must be at least equal to the casing volume from the bottom of the retainer to the bottom perforations plus 0.5 m3.
        ii. The final squeeze pressure must be a minimum of 7 MPa above the current reservoir pressure of the Exshaw.
20. Sting out of retainer and balance a 30 m cement cap on the retainer. Pull and stand tapered tubing string.
21. Change tubing handling equipment and pipe rams to 139.7 mm. Attempt to unlatch from Ultrapack Liner top packer.
    - Contingency: if unable to unlatch, chemical cut 139.7 mm tie-back string above seal assembly

22. Once released from permanent liner hanger, top up with fresh water and pressure test entire wellbore to 7000 kPa for 10 minutes, pending results a bridge plug may need to be set before running logs.
23. Pull and lay down 139.7 mm tie-back string.
24. If required: run and set 244.5 mm bridge plug as close as practicable to liner hanger packer at 3217 mKB. Pressure test 244.5 mm casing to 7000 kPa for 10 minutes.
25. Allow wellbore to stabilize before logging. Rig in wireline unit, run noise-temperature logs as per wireline proposal from bridge plug to surface. Send logs for interpretation.
26. Pending results of initial cement squeezes and review and interpretation of logs, additional cement squeezes will be conducted to repair SCVF at depths to be determined.
27. Contingency:
    - Perforate the identified SCVF source(s) with a 127 mm x 1 m ERHSC (25 Gram GH, 20 SPM, 60 Deg)
    - Conduct injectivity test in to the remedial perforations with at least 2.0 m3 of fresh water. Design a cementing program based on the injectivity test results. Record the Initial Shut in Pressure.
    - Run in with a 244.5 mm cement retainer on hydraulic setting tool on 73.0 mm tubing and set the cement retainer within 5 m of remedial perforations (sweep the setting area with the MCCL prior to setting to ensure there are no nearby collars). Pressure test cement retainer to 7 MPa for 10 minutes.
    - Move in C&A unit, bulker and vacuum truck. Conduct slow rate cement squeeze through the cement retainer in to the remedial perforations.
        i. The cement volume squeezed must be at least equal to the casing volume from the bottom of the retainer to the bottom perforations plus 0.5 m3.
        ii. The final squeeze pressure must be a minimum of 7 MPa above the current reservoir pressure
    - Sting out of the retainer and balance a 30 m cement cap on the retainer
    - Pull and lay down tubing.
28. Pending results of cement squeezes on SCVF, rig out service rig.

3.2 Surface Abandonment

1. Conduct surface casing vent flow test to confirm the wellbore can be cut and capped. Fill out and sign the Surface Casing Vent Flow data sheet. Also ensure there is no pressure on the wellbore. If no evidence of gas migration or surface casing vent flow exits, proceed with cut and cap operation.
2. Excavate a ditch / hole around the wellhead down to a depth of 2.5 m.
3. Ensure no wellhead pressure has built up by opening the casing or tubing valve. Perform a LEL atmospheric measurement in the excavation to ensure cutting operations are safe. Secure the wellhead with overhead rigging. Cut two windows into the production casing – DO NOT EXCEED 1/3 CASING CIRCUMFERENCE WITH EITHER WINDOW. Cut off both casings so that the production casing is recessed lower than the surface casing and that both casing strings are at least 2.0 meters below ground level when capped. Ensure all workers are fully prepared for well head and casing movement during this operation and are protected accordingly.
4. TACK Weld a metallurgic ally compatible steel plate across the production casing, using non continuous fillet welds to allow the production string to vent. Weld a separate steel plate in a similar fashion onto the surface casing. Weld the first two numbers of the location onto the top of the surface casing plate for future identification (i.e. – LSD-SECTION).
   - NOTE: All steel plates must be compatible with the production casing to avoid corrosion.
5. Fill in the excavation above the casings. Remove all debris and move off location. Install post and sign at casing stub location with the following information:
   - NOTE: No fluid or solids waste is anticipated during the operations.



6. Inform the field foreman that the job is complete.

7. Rig out and release all equipment. Note: All waste should be handled in accordance with PPR NWT Waste Management Plan document.
8. Prepare a sketch of the lease, including surplus equipment, contaminated area, etc. and forward to Calgary.

3.3 Daily Reports

Daily activity report for the preceding 24 hours is to be in typed form and emailed to Vertex Professional Services weekdays prior to 7:30 A.M. MST time. VPS's Calgary email is reports@vertex.ca. On weekends email field copy of report daily to contacts listed below.

After hours, weekdays or holiday, call the advised appointed contact at:

Jonah Urton	jurton@vertex.ca
Vertex Professional Services	(587) 580-8514 (cell)
David Duncan	dduncan@ppr.ca
Prairie Provident	(403) 292-8188 (office)
	(403) 660-1821 (cell)
Brad Likuski	blikuski@ppr.ca
Prairie Provident	(403) 292-8034 (office)
	(403) 512-8305 (cell)
Rob Lemermeyer	rlemermeyer@ppr.ca
Prairie Provident	(403) 292-8046 (office)
	(403) 554-2202 (cell)

NOTES: All operations carried out on behalf of Prairie Provident shall be conducted in a safe manner, in compliance with the occupational health and safety act, Office of the Regulator of Oil and Gas Operations regulations, and any other relevant act, regulation, or law.

Prairie Provident's operations must protect and maintain the quality and integrity of the environment in compliance with all environmental acts and regulations.

All tickets to be stamped and labeled with the AFE number or cost center number, coded and signed by the Completion Field Supervisor.

All contracted services must have an on-going safety program in place, which is being implemented and monitored.

A copy of this program shall be on location at all times.

Ensure that CAODC safety inspections are completed on a weekly basis and emailed to VPS's Calgary office.

Ensure safety meetings are held on a weekly basis with each crew. Minutes of these meetings are to be forwarded to VPS's Calgary office with the morning report and noted in the tour book.

Ensure that daily BOP function tests are conducted and noted in the tour book.

Ensure that every seven (7) days a BOP drill is conducted and noted in the tour book.

Ensure that all personnel on site are aware of Prairie Provident's EH&S policy

Ensure pre-job safety meetings are held and documented.

Ensure all personal protective equipment is in place and kept in good usable condition.

Ensure that all personnel are wearing/using personal protective equipment as required.

Ensure that hazards are identified and marked where required:

- Sump fences or markers should be in place
- Check and locate pipelines, power lines, and telephone lines before digging or trenching

Ensure that all spills are reported and cleaned up or recovered; this includes spilled drilling fluid, oil, produced water, diesel fuel or other chemicals.

Ensure that all wastes are disposed of in an approved manner, whether they are liquid or solid wastes.

Review MSDS sheets with crewmembers when handling hazardous chemicals.

Ensure that first aid equipment and supplies are in the designated location and readily available for use.

Record the fire extinguisher's number and location and ensure that they have recent inspection tags on them.

Ensure that all confined areas around the rig are thoroughly checked out with both a toxic gas detector and explosive meter, before workers enter the confined spaces.

Ensure that the air quality is monitored on locations where H_2S may be present.

Supervisor and the rig manager should be familiar with Prairie Provident's emergency response plan. When working in an area where Prairie Provident does not have an established field operation, the supervisor and rig manager will be responsible for the initial implementation of the ERP.

Ensure that security around the wellsite is adequately maintained, to prevent unauthorized entry, and prevent the theft and damage of materials and supplies.

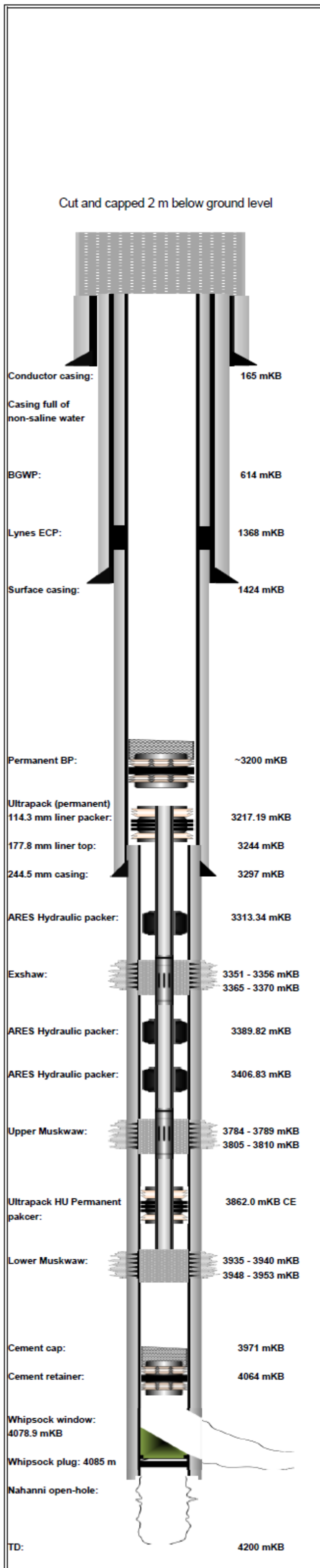
ALL OPERATIONS WILL CONFORM TO ALL CURRENT OROGO, OH&S AND PRAIRIE PROVIDENT RESOURCES CANADA LTD. REQUIREMENTS.

3.4 Services

Table 3 – Service Contacts

Service	Name	Number
Wellsite Supervisor	TBD	
PPR Foreman	TBD	
Rentals	TBD	
Cementers	TBD	
Testers	TBD	
Wireline	TBD	
Slickline	TBD	
Fluid Heating	TBD	
Water Source	TBD	
Fluid Hauling	TBD	
Fluid Tanks	TBD	
Wellhead / Frac-head	TBD	
Service Rig	TBD	
Safety (medic)	TBD	
Production Tubing	TBD	
Hydraulic Catwalk	TBD	

4 APPENDIX A – DOWNHOLE SCHEMATIC POST ABANDONMENT



WELLBORE PROFILE

Prairie Provident Resources Canada Ltd.

S. Pointed Mountain (D-1) L-68

UWI:	300/L-68-60-20-123-45/1	**Licence:**	1207	**Date:**	April 29, 2021
Surface:		**Deviation:**	Deviated	**AFE / Job #:**	

ELEVATIONS & DEPTHS (m)

TMD	4200.00	**KB ELEV**	737.00	**KB TO SCF**	
TVD	4139.86	**GL ELEV**	723.00	**KB TO THF**	4.70
PBTD	3971.00	**KB - GL**	14.00	**Well Status**	Suspended

CASING DESCRIPTION & GRADE	OD (mm)	WEIGHT (kg/m)	TOP LOCATION	LANDED DEPTH (m)
Conductor Casing: SOO-95, LT&C	508.0	139.9	Surface	165.00
Surface Casing: SOO-95, LT&C	339.7	107.2	Surface	1424.00
Production Casing: SOO-95, LT&C	244.5	64.7	Surface	3297.00
Liner: SOO-95, LT&C	177.8	38.7	3244	4130.00
Tie-back: P-110, LT&C	139.7	34.2	Surface	3217.20

Perf Date	Zones	Top Shot	Bottom Shot	Status	Gun Data
5-Sep-11	Exshaw	3351.00	3356.00	Cemented	17 SPM, 25 gr, 60°
5-Sep-11	Exshaw	3365.00	3370.00	Cemented	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3784.00	3789.00	Cemented	17 SPM, 25 gr, 60°
4-Sep-11	Upper Muskwa	3805.00	3810.00	Cemented	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3935.00	3940.00	Cemented	17 SPM, 25 gr, 60°
4-Sep-11	Lower Muskwa	3948.00	3953.00	Cemented	17 SPM, 25 gr, 60°
12-Oct-82	Nahanni	4079.80	4200.00	Abandoned	Whip-stock, open-hole
13-Sep-82	Nahanni	4130.00	4200.00	Abandoned	Open-hole

DOWNHOLE DESCRIPTION FROM BOTTOM UP (Tubing String)

QUANTITY	DESCRIPTION	LENGTH (m)	TOP OF (mKB)
1	125 mm pump out shoe (28.7 MPa shear)	0.25	687.27
2	3 - 114.3 mm, 22.47 kg/m, P-110 casing joints	34.25	653.02
3	114.3 mm pup joint	2.76	650.26
4	149 mm Weatherford Ultrapak HU hydraulic set permanent packer	3.40	646.86
5	4 - 114.3 mm, 22.47 kg/m, P-110 casing joints	46.19	600.67
6	139.7 mm Weatherford frac sleeve port (84 mm ball seat)	1.23	599.44
7	35 - 114.3 mm, 22.47 kg/m, P-110 casing joints	403.64	195.80
8	147.3 mm ARES Hydraulic set open-hole packer	3.60	192.20
9	1 - 114.3 mm, 22.47 kg/m, P-110 casing joint	11.55	180.65
10	114.3 mm pup joint	1.86	178.79
11	147.3 mm ARES Hydraulic set open-hole packer	3.60	175.19
12	1 - 114.3 mm, 22.47 kg/m, P-110 casing joint	11.35	163.84
13	114.3 mm pup joint	3.07	160.77
14	139.7 mm Weatherford frac sleeve port (89.2 mm ball seat)	1.23	159.54
15	5 - 114.3 mm, 22.47 kg/m, P-110 casing joints	57.23	102.31
16	147.3 mm ARES Hydraulic set open-hole packer	3.60	98.71
17	8 - 114.3 mm, 22.47 kg/m, P-110 casing joints	91.85	6.86
18	219.1 mm Ultrapack Liner Top Packer	1.40	5.46
19	176.9 mm Ultrapack Latch Seal Assembly	0.76	4.70

WEIGHT OF TUBING STRING (daN)		**TOTAL STRING LENGTH**	682.82
TENSION/COMPRESSION (+/- daN)		**STRETCH/SLACKOFF (+/- m)**	
LANDED STRING WEIGHT (daN)	-	**TUBING BOTTOM (mKB)**	687.52

WELLHEAD DESCRIPTION

ITEM #	DESCRIPTION	SERIAL #	MWP (MPa)	SIZE (mm)
	Casing Bowl		35.0	346 x 339.7
	Upper flowing style wellhead		69.0	279.4 x 139.7

ABANDONMENT SPECIFICS

ZONES	SCVF / GM	LOW CEMENT	REMEDIAL	TUBING (Y/N)	RODS (Y/N)
1	Repaired	N	N	Y	N

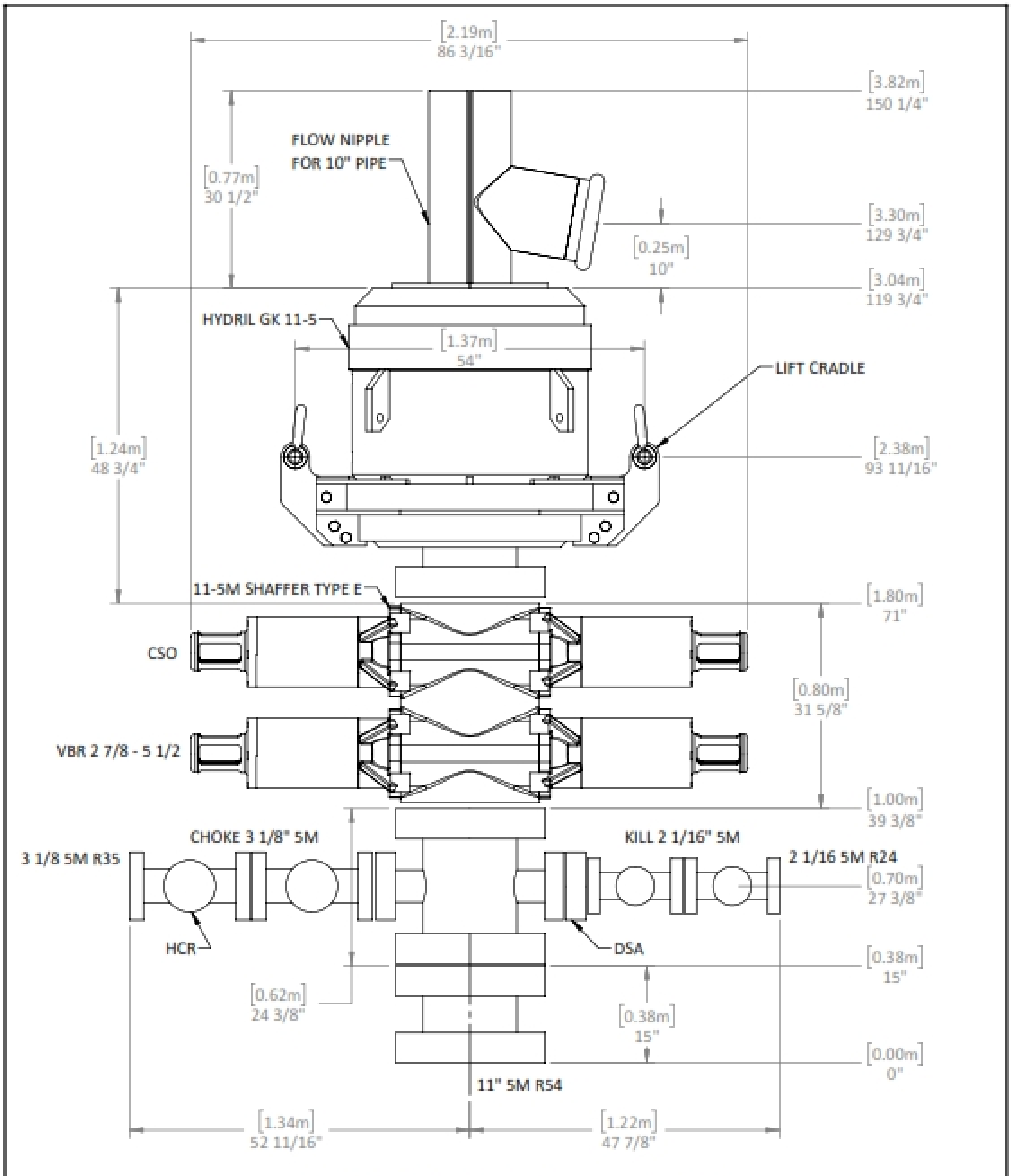
REMARKS

Prepared by: Jonah Urton

5 APPENDIX B – WELL CONTROL EQUIPMENT REQUIREMENT

Well Control Equipment Requirements

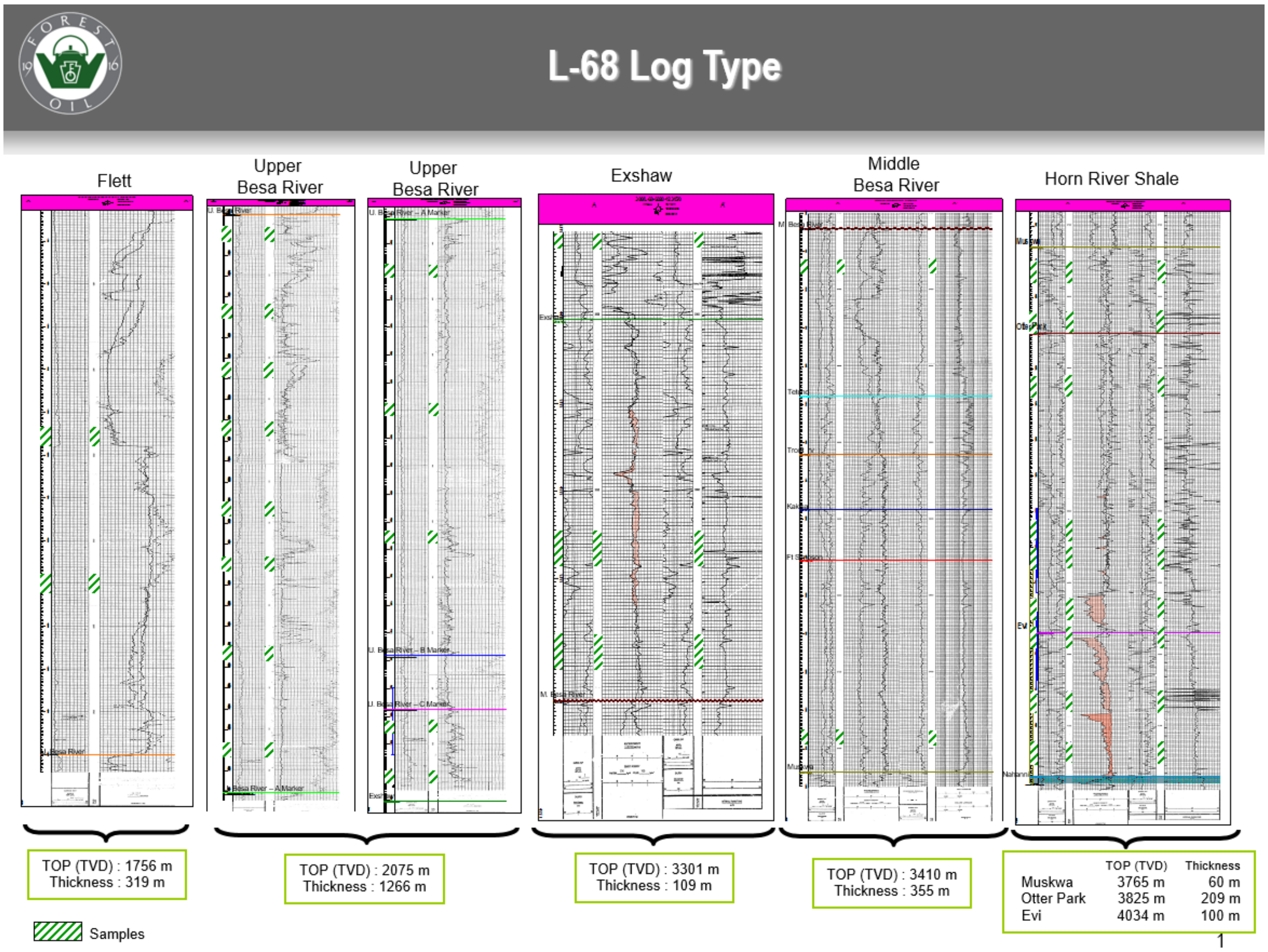
- A well servicing 35 MPa blowout preventer (BOP) stack will be used for well control (see schematic below
  - The BOP stack will consist of
    - Work spool
    - Pipe rams (sized tubing installed in the 2K-02 wellbore – 139.7 mm tie-back string and 73 mm workstring)
    - Blind rams
    - Annular Preventer
    - Remote Controls
- The BOP stack was chosen for two reasons:
  - The working pressure of the stack is well above the expected bottomhole pressure
  - The addition of the Annular Preventer allows for an additional level of backup for the pipe rams when tripping tubing, pumping kill fluid, etc.
- An appropriately size 35 MPa pump will be mobilized to the location with the service rig for well kill operations
- Enough kill fluid for 2 times the hole volume will be mobilized to location for well kill operations.



ICON ENERGY SERVICES	THE INFORMATION INCLUDED IN THIS DOCUMENT IS PROPRIETARY AND SHALL NOT BE REPRODUCED, TRANSFERRED, OR DISCLOSED TO OTHERS, FOR ANY PURPOSE WHATSOEVER, WITHOUT THE WRITTEN AUTHORIZATION OF ICON ENERGY SERVICES.	DRAWN: EJN	CUSTOMER: STAR VALLEY DRILLING
		CHECKED:	FILE: 11771
	SHEET 1 OF 1	APPROVED:	TITLE: 11-5 BOP LAYOUT
	SHEET SIZE: A REV: 0	DATE: 2019-08-20	DWG#: 115660

VERTEX

6 APPENDIX C – GEOLOGICAL INTERPRETATION



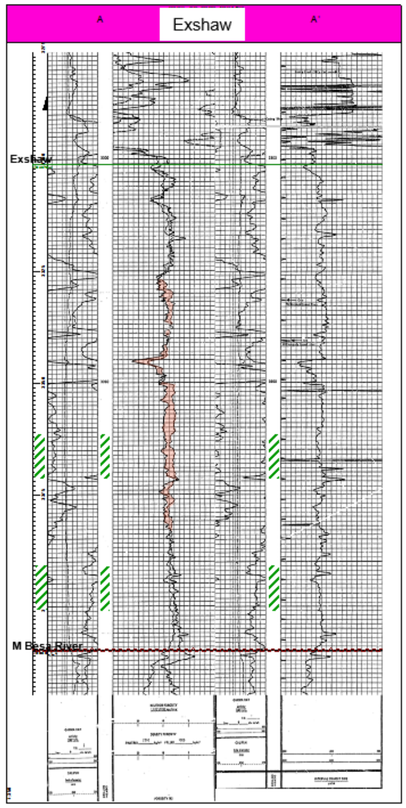
Exshaw and Horn River Shale - L-68 Log Type

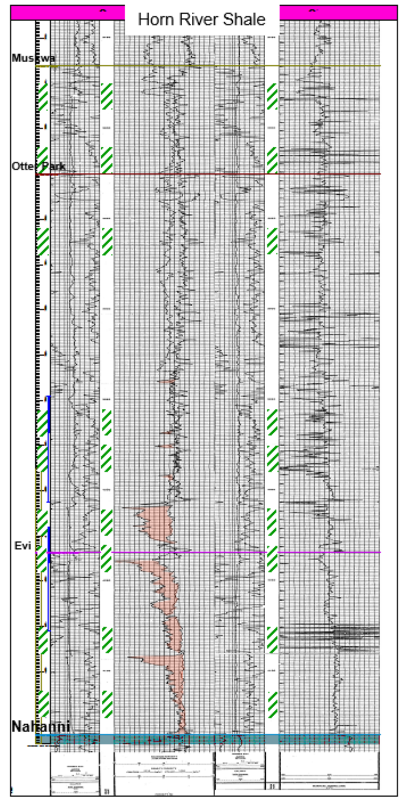
L-68

Formation	Top (TVD)	Thickness
Upper Besa River	2075 m	1226 m
Exshaw	3301 m	109 m
Middle Besa River	3410 m	355 m
Horn River Shale		
-Muskwa	3765 m	60 m
-Otter Park	3825 m	209 m
-Evi	4034 m	100 m
Nahanni	4134 m	

Presence of X-over and porosity in the Exshaw and Horn River Shale intervals

Samples





2

VERTEX

L-68
Interpretation of Gas-Mud Log

From Well Report:

- *195m geological description (5m samples) and mud logging began (continued to TD)*
- *577m drilling break. Fresh water kick from Mattson Formation.*
- *1227m sour gas bubbling to the surface.*
- *1530-1575m (**45m thick**) oil staining in the Flett Formation. 3-6% porosity*
- *1688-1703m (**15m thick**) gas readings 2000-6000 units from fair porosity.*
- *1744-1751 (**7m thick**) 8000 units with heavies, oil stain 1745-1755.*
- *1965-1970, 1975-1980 fracture porosity. Gave 3800 units at 1961 and 6000 units at 1972.*
- *2251-2255m (**4m thick**) porous limestone 3-6% porosity. 2750 units average – peak of 5000 units at 2250m.*
- *2340-2346m (**6m thick**) porous limestone 3-12% porosity, 3500 units average – peak of 9000 units at 2343m*
- ***[77m net anomalous hydrocarbon-rich section in interval 1530-2346]***
- *2373m severe gas cutting in the mud. 1.5m flare.*
- *2679m gas kick.*
- *2880 onward. Background gas remained high averaging 1900 units, C1, traces of C2. The degasser was run and flared off from 2800m onwards to control the gasified mud.*
- *3285.5 Schlumberger ran the CNL density log over the interval 3285.5 – 165. No other logs were run over this interval because of deteriorating hole conditions.*

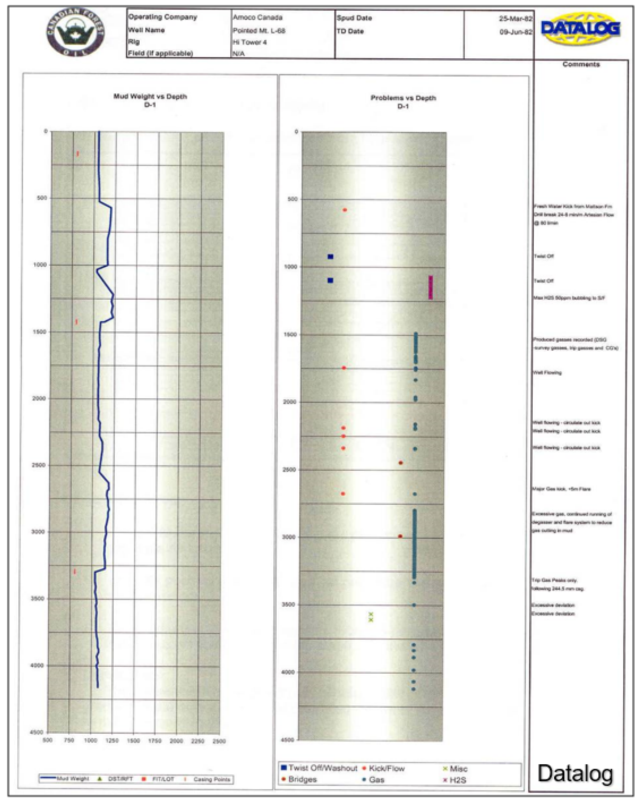


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Figure 5 - Geological Interpretation of Logs

AMOCO POINTED MOUNTAIN D-1

Geological and mud logging began at 195 m and continued to a total depth of 4200 m.

The hole was spudded on March 25, 1982. The surveyed ground elevation was 726.3 m, K.B. elevation 737 m.

A 660 mm surface hole was drilled to 166 m and 508 mm surface casing landed and set 166 m. A 445 mm hole was then drilled to 1424 m and 340 mm casing run and set at 1424 m. A 311 mm hole was drilled to 3297 m and 245 mm casing run and set at 3297 m. Total depth was reached on September 6, 1982 at 4200 m.

Samples were caught at 5 m intervals from 195 m to 4200 m, T.D., and spot samples taken when necessary.

AMOCO POINTED MOUNTAIN D-1

FORMATION DESCRIPTIONS

Mattson: - 1453 m

The first formation to be logged was the Mattson sandstone. From 200 - 229 m chert was drilled at an average rate of 16 min/m.

The chert was:

Cht - wh - gy wh, mot, occ m gy, ang, brit, tr calc xls

Under this chert was interbedded siltstone and sandstone to 654 m. The sandstone appeared to be of two main types:

#1 Ss - lt gy gy-wh vf - fgr, ang - sb ang w srtd, sl calc clr qtz, no show

#2 Ss - clr, wh, lt gy- vr-fgr, dr qtz, calc & sil cmt, f consol, p por, no show

Sltst - dk - m gy, m hd, sl sdy - shly i/p, bit i/p.

The drilling rate through this section was approximately 30 min/m.

At 654 m, dolomite was encountered and was interbedded and intermixed with sandstone to 740 m.

Dol-Ss - wh dol matrix/clr qtz grs, f gr, sb ang, p srtd, framework 4-5 tt, no show

grdg to

Dol - wh. lt gy - lt brn, micxl - fxl, sndy i/p, sl calc cmt, tt, no show

The drilling rate through this section was approximately 47 min/m.

From 740 - 1453 m the geology was interbedded sandstone and shale. The sandstone was predominantly:

Ss - wh - lt gy, vf - fgr, dol cmt, sm sil cmt, p-f consol, p por, arg i/p, tt, qtz, sbrd, no show

Sh - m - dk gy, carb - bit, micmica i/p, slty - sndy i/p, sbfiss, slty, tr pyr

AMOCO POINTED MOUNTAIN D-1

FORMATION DESCRIPTIONS

Mattson: - 1453 m - continued

The drill rate through this section averaged approximately 52 min/m. Throughout this last section, dolomite stringers appeared randomly.

Average Mud Weight 1050-1230 kg/m^3
Average Viscosity 48-55 sec/L

The background gas ran at a low 5-100 units through the Mattson. No oil staining was noted.

Mississippian - 1453 - 2496 m

The Mississippian limestone was encountered at 1453 m. From here to 1766 m it was predominantly limestone with the occasional stringers of shale. The limestone was:

Ls - wh - buff - lt gy, crpxl - micxl, frm, arg, crin i/p, dol i/p, tr intxl por

From 1530 - 1575 m, there was some oil staining, light green fluorescence with fair cut and intercrystalline porosity plus a trace of vuggy porosity. Visual porosity in the limestone was estimated at 3-6%. Background gas through this zone averaged 30-60 units. High gas readings were logged from 1688 - 1703 m. 2000-6000 units with heavy gases present, resulting from fair porosity, and from 1744 - 1751 m, averaging 8000 units with heavy gases present, and circulated out after checking for flow in both cases. Heavy oil, green fluorescence, fair cut, were noted in the shale from 1745 - 1755 m. Average drill rate was 29 min/m.

The limestone graded to a calcareous shale at 1766 to 1816 m. The shale was:

Sh - m - dk gy, calc, brit, hd, dol i/p, sil i/p, blky, blky fiss

At 1816 to 2169 m the Mississippian returned to a limestone lithology with occasional interbedded shale.

Ls - lt - m gy, gy - brn i/p, grdg to sh, crpxl - micxl, arg, dol i/p, sm ~h calc xls

At 1965 - 1970 m and 1975 - 1980 m there was some fracture porosity producing a maximum 3800 units gas at 1961 m and 6000 units at 1972 m with an average 280-400 units background. No oil stain was noted. Average drill rate through this section was 27 min/m.

AMOCO POINTED MOUNTAIN D-1

FORMATION DESCRIPTIONS

Mississippian - 1453 - 2496 m - continued

At 2163 m the Mississipian again graded back to a shale,

Sh - lt - m gy, calc cmt, calc - v calc, lmy i/p, micmica, hd, brit

which continued to 2469 m where the Banff Shale began. There were two beds of limestone in this section, 2251 - 2255 m and 2340 - 2346 m, which proved to be porous and produced gas.

The first limestone bed 2251 - 2255 m, described as:

Ls - gy - wh, arg, sil, crpxl - micxl, frac por, 3-6%, no stn and the second limestone bed 2340 - 2345 m, described as:

Ls - gy - wh, micxl - vfn gr xls, g por, intxl por, 3-12% visual por, poss sm frac por, foss, n flor, sil i/p, no stn

The first bed produced a background average of 2750 units with a peak of 5000 units at 2250 m. The second limestone bed produced an average of 3500 units with a peak of 9500 units at 2343 m.

The average drill rate of this section 2163 - 2469 m was 20 min/m.

Average Mud Weight 1230 - 1115 kg/m^3
Average Viscosity 50 - 57 sec/L

Banff Shale - 2496 - 3150 m

This formation was completely shale with a few siltstone stringers.

Sh - m - dk gy, carb, fiss, mod frm, sl foss i/p, micmica, sl calc - calc, slty i/p, pyr i/p

Background gas remained high throughout the drilling operation averaging 1900 units, almost all C^1, with traces of C^2. The degasser was run and the well flared off from 2880 m onwards to control the gassified mud. No oil staining was noted throughout the formation. Average drill rate was 25 min/m.

Average Mud Weight 1115 - 1165 kg/m^3
Average Viscosity 43 - 71 sec/L

AMOCO POINTED MOUNTAIN D-1

FORMATION DESCRIPTIONS

Besa River Shale - 3150 - 3780 m

This formation was also shale:

Sh - m - dk gy blk, lt gy i/p, sl calc, sl slty & sil, dol i/p hd, sb fiss - blky, brit

At 3325 m this shale underwent a colour change:

Sh - m gy, occ dk gy, blky - sb fiss, micmica, pyr i/p, hd, brit.

TR - sltst - lt gy, dol cmt, arg

In the 3375 m, 3390 m, 3415 - 3425 m samples, the siltstone increased to 10%:

Sltst - lt - m gy occ wh, lmy - sl dol i/p, arg, sil mod frm - hd

Background gas remained high throughout the drilling to the casing point at 3297 m, averaging 4500 units, all C^1. From casing point to the Horn River Shale (Second Black Shale at 3780 m) the background gas averaged 140 units, all C^1.

Average drill rate to casing point was 28 min/m, from casing point to Horn River Shale was 23 min/m.

Average Mud Weight	1165 - 1180 kg/m^3 to casing, 1040 - 1060 kg/m^3 to Horn River
Average Viscosity	60 - 70 sec/L to casing 50 - 85 sec/L after

There is a suspected thrust fault at 3610 m which increased the thickness of the Besa River Shale.

Horn River Shale (Second Black Shale) 3680 - 4139 m

The Horn River Shale reamined fairly constant in its shale lithology. The upper part may be described as:

Sh - m - dk gy, sbfiss - blky, sl micmica, vsl calc, frm - hd brit i/p, tr pyr, tr calc frac fl

Figure 6 - Geological Review of Cuttings

7 APPENDIX D – ABANDONMENT SCHEDULE

Days	Description of Operations
1 – 3	Equipment mobilization
4 – 5	Rig up, run workstring to retrieve WR plug. Pull and lay down WR plug.
6 – 7	Run milling equipment, rig in power swivel. Mill out ball seats in frac ports.
8	Set cement retainer # 1
9 – 10	Cement squeeze Muskwa
11	Set cement retainer # 2
12 – 13	Cement squeeze Exshaw
14 – 15	Pull tie-back string
16	Set bridge plug, top up casing and allow well to settle
17	Run noise-temperature logs to identify SCVF source(s)
18	Perforate identified sources, set cement retainer #3
19	Cement squeeze remedial interval
20	Monitor SCVF
21	If SCVF has been repaired – cut and cap
22 – 24	Equipment demobilization

VERTEX

8 APPENDIX E – 2021 SITE INSPECTION

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Figure 7 - L-68 lease from helicopter – 2021-04-24

Figure 8 - L-68 lease - 2021-04-24

Figure 9 - L-68 wellhead - 2021-04-29

Figure 10 - L-68 SCVF catch tank - 2021-04-29

Figure 11 - L-68 SCVF catch tank volume - 2021-04-29

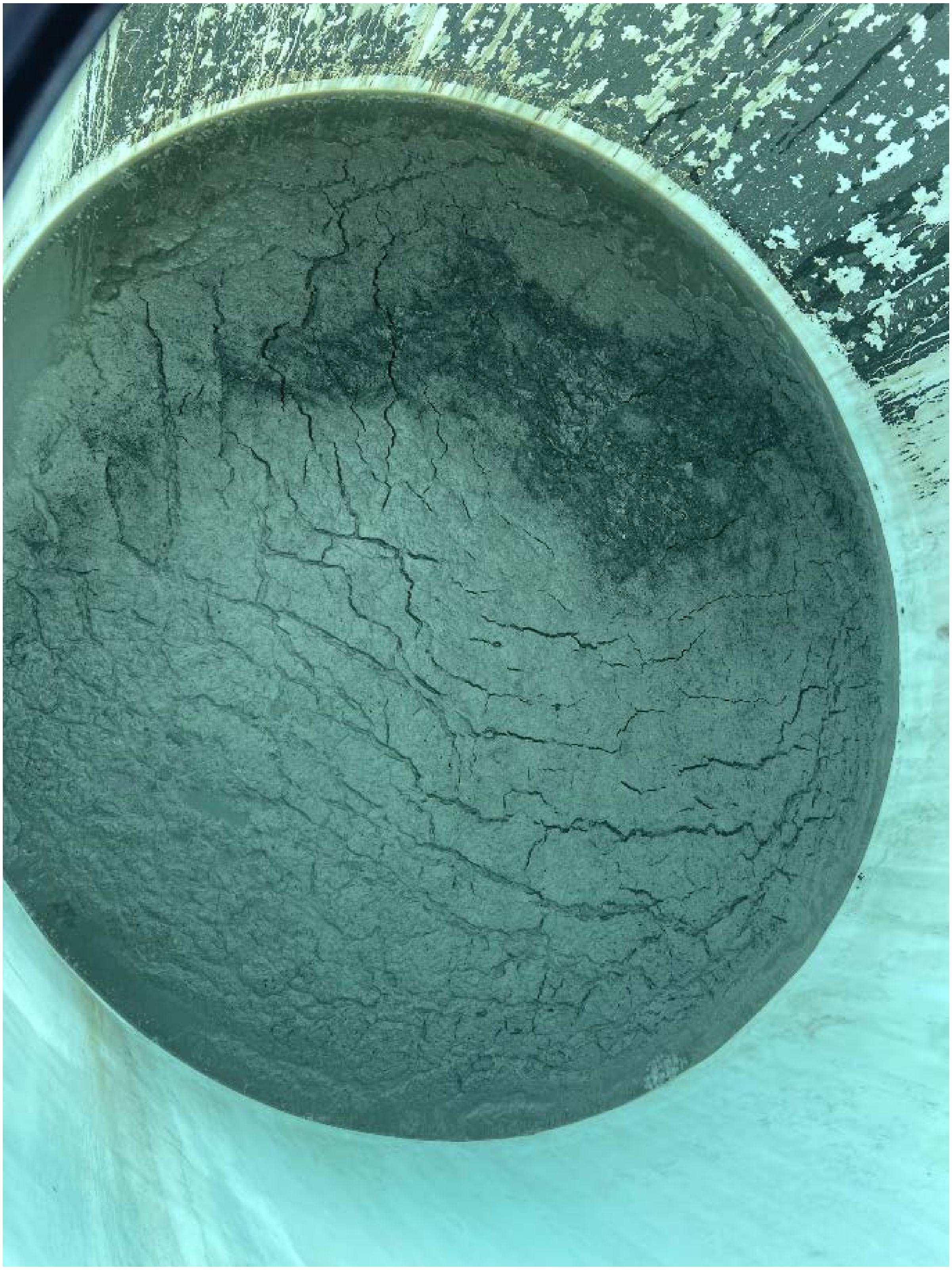

Figure 12 - L-68 SCVF catch tank inside - 2021-04-29

Figure 13 - L-68 SCVF flow meter installation 2021-04-29

9 APPENDIX F – DAILY DRILLING REPORTS

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10 APPENDIX G – DAILY RE-ENTRY AND RE-COMPLETION REPORTS

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11 APPENDIX H – CEMENT BOND LOG AND INTERPRETATION

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