APPLYING EXTENDED REACH DRILLING TO OPTIMIZE THE NET PRESENT VALUE OF THE DUVERNAY FIELD

A Thesis

Presented to the

Faculty of the Department of Petroleum Engineering

University of Houston

In Partial Fulfillment of the Requirements for the Degree

Master of Science

In Petroleum Engineering

By

Mark Gregory Edward Smith, PEng

August 2015

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Abstract

Lateral length is a key well design parameter that impacts field planning, operations, hydrocarbon recovery, reserves booking and economics. Unconventional assets in North America are looking at long laterals as a potential to reduce Unit Development Costs (UDC) and maximize Net Present Value (NPV).

This thesis provides a detailed account of the planning, execution, and appraisal of a 2500m long lateral pad in the Duvernay formation. It then describes a 3600m long lateral in the Montney formation, and captures the lessons learnt and how they could be applied to the Duvernay. The final stage of this thesis investigates the technical and design implications for drilling wells from 2000m up to 4500m and matches them with cost and production forecasts. Based on the economic results it is found that the most economical well for the Duvernay is in the range of 3000m to 3500m in lateral length.

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List of Abbreviations

BHA	Bottom Hole Assembly
ALARP	As Low As Reasonably Possible
boe	Barrels of Oil Equivalent
Cl	Chlorides
ECD	Equivalent Circulation Density
EUR	Estimated Ultimate Recovery
H2S	Hydrogen Sulfide
mboe	Thousand Barrels of Oil Equivalent
MD	Measured Depth
MWD	Measure While Drilling
NPV	Net Present Value
PV	Plastic Viscosity
RPM	Rotations Per Minute
TD	Total Depth
TnD	Torque and Drag
UDC	Unit Development Cost
VIR	Value Investment Ratio
YP	Yield Point

Chapter 1

1. Introduction

This thesis describes the Duvernay formation in western Alberta. Then it describes the planning, execution and appraisal of a 4 well lateral length trial in the Duvernay which Shell performed in 2013. Then it explores what has been learned from the extended reach drilling trial which was done by Shell in the Montney formation and discusses the technical enablers which could be used in the Duverany to increase the lateral length. It demonstrates the technical design and equipment requirements for drilling a Duvernay well with a lateral length of 2000m, 2500m, 3000m, 3500m, 4000m and finally 4500m. Finally it explores the economics of each scenario based on the estimated cost and production forecast for each design.

1.1 Description of the Duvernay

The Duvernay is a liquid-rich shale formation located in the West Central region of Alberta Canada. Shell has acquired a sizeable position in the Duvernay which is highlighted in red in figure 1.1. This thesis will focus on Shell's development region of the Duvernay located in township 63, range 20 West of the 5th meridian. There are varying pore pressures, fracture gradients, formation depths, H_2S risks, and many other conditions that are not constant throughout the Duvernay field. The geological conditions which will be used in this thesis are given in Table 1.1.

Figure 1.1 Fox Creek Duvernay

Table 1.1 Geological Conditions of the Duvernay Field

H_2S Bearing Formations	Nordegg	3.3%
	Wabumun	16.3%
	Winterburn Group	29.1%
Bottom Hole Temperature		110 deg C
Bottom Hole Pressure		55,260 KPA
Ground elevation above mean sea level		785m
Total Vertical Depth – Sub Surface		2285m
Total Vertical Depth – Ground Level		3070m

In this development region of the Duvernay all H_2S formations are covered with the intermediate casing string which will be set in the Ireton formation for all design concepts. In other regions of the field the Winterburn Group does not contain H2S which allows for a higher intermediate casing point, however that design concept is not covered in this thesis. In some regions of the field the Duvernay formation has the potential for sour production which has an impact on the production casing design, however in the core development region the Duvernay has been proven to not contain H_2S so all production casing strings for this thesis will be designed for sweet production.

1.2 Project Relevancy

With the current development strategy Shell will require 1491 horizontal wells in order to effectively develop their Duvernay acreage. Longer laterals have the potential to reduce the cost per foot of each well, lower the Unit Development Cost, reduce the dead space, reduce the environmental footprint, and maximize the Net Present Value of the field.

1.3 Approach and Assumptions

There are many drilling and completion trials ongoing in the Duvernay, but for the purpose of this thesis all variables other than lateral length will remain constant. There are also different regions of the field which have different pressures, different drilling concerns, different depths and different production forecasts. The formation properties and production forecasts will be based on region of the field located in T63-R20-W5 which has been moved into full scale development. Similar economics could be performed to the other regions of the field, but that is outside of the scope of this thesis.

1.4 Pad Layout

In this thesis it will be assumed that all pads consist of 8 horizontal wells drilled south with a 200m well spacing (8 wells per section). It will also be assumed that the surface location is centralized giving a maximum horizontal step out of 700m for the outer wells on the pad. Lateral Length (L) will be measured from the heel location when the wellbore is at 90 degrees in the reservoir until total depth at the toe.

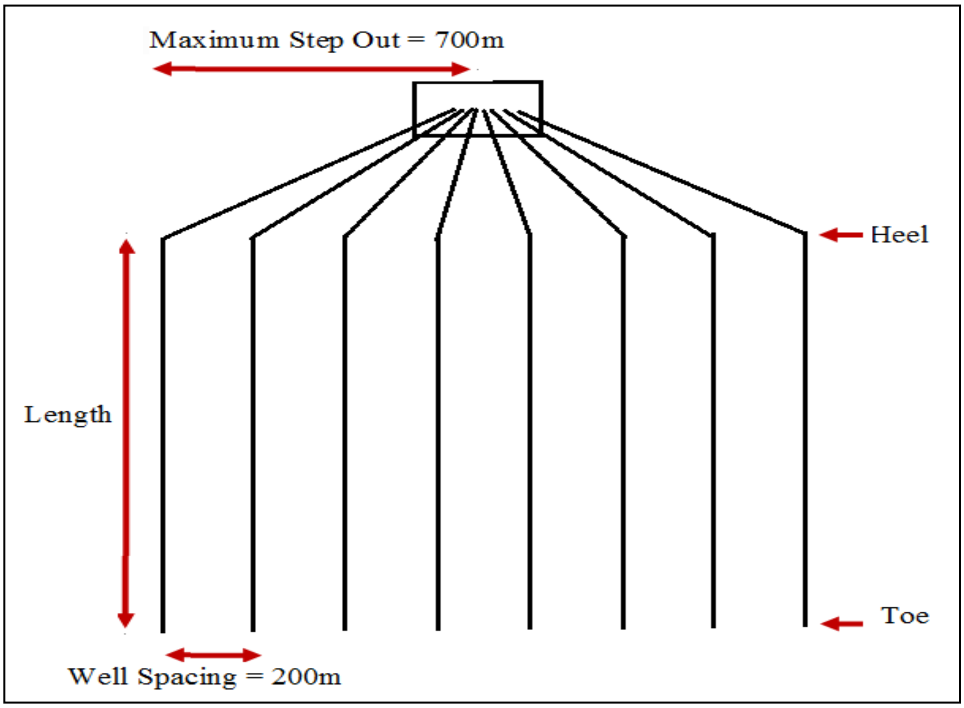

Figure 1.2 Duvernay Development Pad Layout

1.5 Well Design and Assumptions

For the purpose of this thesis it will be assumed that there will be a 139,7mm (5.5") cemented completion in the horizontal section of the wellbore. The surface and intermediate casing points will remain constant for all designs. Setting surface casing at a depth greater than 600m is a requirement from the Alberta Energy Regulator (AER) in order to protect groundwater. The intermediate casing will be set in the Ireton formation, thereby covering off all potential H_2S bearing zones, so that the production casing string does not need to be sour service. The intermediate casing string also isolates all under pressured formations preventing lost circulation when increasing the mud weight to drill into the over pressured Duvernay. The production casing will be designed in order to accommodate a maximum pressure of 90 MPA during the completion with a minimum safety factor of 1.1. Refer to figure 1.3 for the well design schematic.

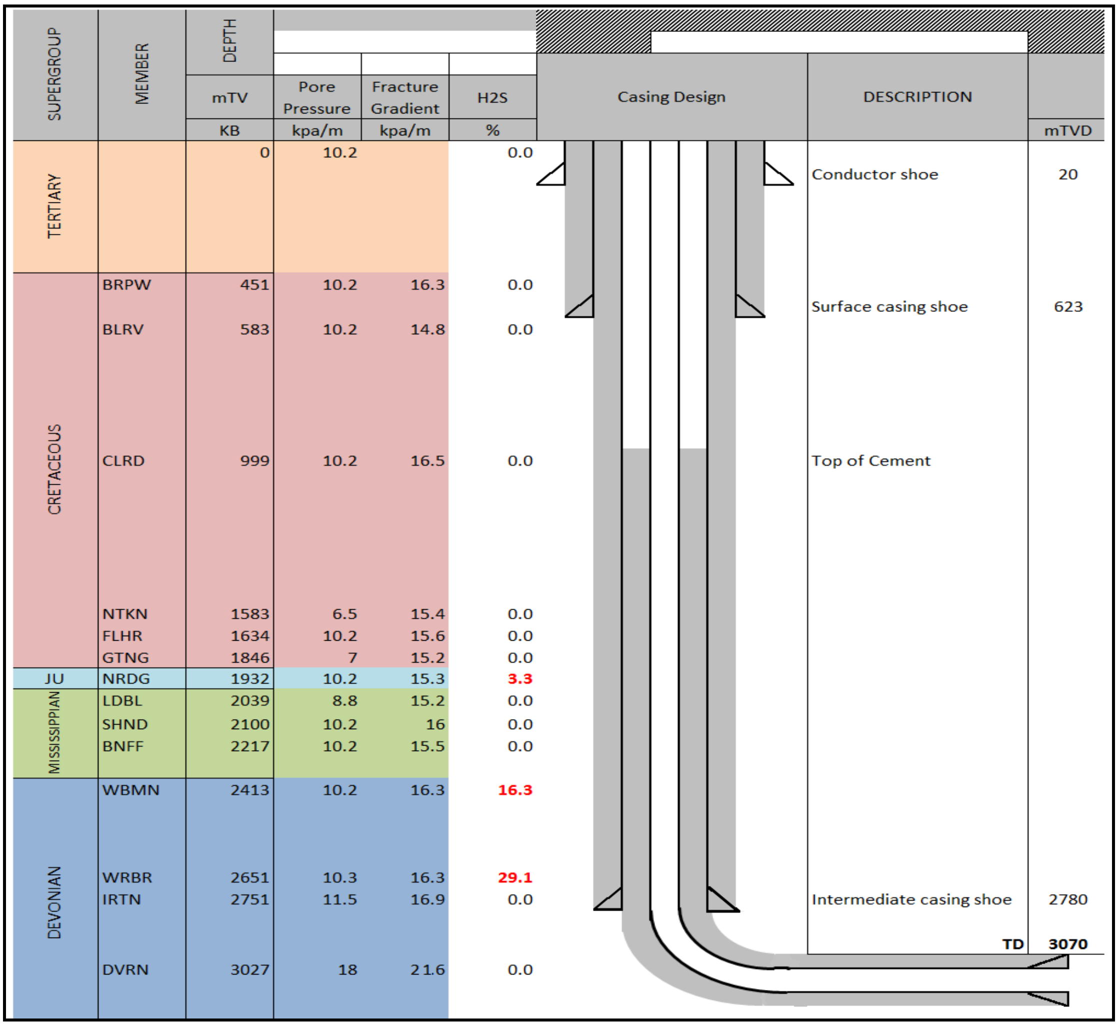

Figure 1.3 Duvernay Well Schematic

1.6 Completion Design

The completion design will be constant for all lateral length trials. There will be a 139.7mm (5.5”) cemented production casing string in the lateral which will be completed with a “plug and perf” method consisting of 20m cluster spacing where each cluster consists of 7 perforations. The completion will begin at the toe, and after each stage is completed a bridge plug will be pumped down on wireline along with the next perforation guns. After setting the bridge plug to isolate off the lower stage, the next stage is perforated and after retrieving the perforation guns the next stage is pumped.

The maximum pressure rating of the current production casing is 90 MPA for all lateral length development scenarios. This maximum pressure allows 6 clusters to be perforated and completed at the same time for the first 2000m of the lateral. Beyond 2000m into the lateral the pump rate will be reduced and fewer clusters will be completed during a single stage in order to keep the surface pump pressures within the equipment limit. For every development scenario the same amount of fluid and proppant will be pumped for every cluster. There have been multiple studies done on completion design in the Duvernay, but for this thesis the assumption will be made that the completion design will be constant for all wells. The production type curves and economics will be based on this completion design described in Table 1.2.

Table 1.2 Duvernay Completion Design

Fluid Volume Per Cluster (m3)	260
Proppant Per Cluster (Tonnes)	30
Cluster Spacing (m)	20
# Holes/Cluster	7

Chapter 2

2. Duvernay Long Lateral Trial

2.1 Duvernay Long Lateral Planning

Fox Creek 19 is a 4 well pad with a surface location of 6-2-63-18W5 and was Shells first attempt at moving towards longer lateral wells in the Duvernay formation. It was planned as a four well pad consisting of two short laterals ~1600m and two long laterals ~2500m as shown in table 2.1. Based on the torque and drag modeling in Figures 2.2 and 2.3 it was determined that these long laterals were at the limit of what was technically possible with the current rig and casing. Drilling fluids, wellbore geometries, casing running equipment and cement programs were optimized to accommodate the longer lateral. Planning a lateral beyond 2500m was determined to require major design and equipment changes so it was decided to first understand the relation between lateral length and production from the Fox Creek 19 pad before further pursuing extended reach laterals in the Duvernay.

Table 2.1 Fox Creek 19 Well Specifications

	FC19A 12-27-62-18W5	FC19B 11-27-62-18W5	FC19C 7-34-63-18W5	FC19D 8-34-63-18W5
Measured Depth	**5722m**	**5608m**	**4751m**	**4718m**
Completed Lateral Length	**2541m**	**2464m**	**1617m**	**1598m**

These wells had a total vertical depth (TVD) of 2925m. The wells were all drilled from North to South with a horizontal spacing of 300m. The wells were batch drilled meaning that all 4 surface holes were drilled first followed by all the intermediate holes and finally all of the production holes. The batch drilling sequence was chosen so that FC19D drilled its production section first where it collected a core sample before plugging back and sidetracking to drill the first lateral that was only 1598m in lateral length. The long laterals were drilled last leaving FC19A till the end since in addition to its length it had a 510m step out making it the longest well with a total measured length of 5722m giving it the highest drag while drilling and running casing.

Table 2.2 Fox Creek 19 Batch Drilling Sequence

	FC19A (Long)	FC19B (Long)	FC19C (Short)	FC19D (Short)
Surface	4	3	2	1
Intermediate	5	6	7	8
Production	12	11	10	9

2.1.1 Directional Plans

The directional plan is a huge enabler for drilling a long lateral in that it can minimize the drag while drilling and while running the production casing. While drilling drag increases the torque seen at surface while rotating and when using a bent housing motor it makes it difficult to get weight to the bit and to hold a tool face when sliding to steer in the lateral. When running the production casing drag increases the force required to push the casing into the lateral section of the hole. If the drag gets high enough the casing can experience helical buckling where it will lock up with the borehole wall and prevent the casing from reaching total depth. The annular clearance between the 127mm production casing and the 165mm wellbore is relatively tight which minimizes the effects of helical buckling, but with this tight tolerance in the lateral it is very important to have a clean wellbore free of cuttings to allow sufficient room for the casing and to prevent the cuttings from packing off. In order to optimize the torque and drag the following design characteristics were incorporated into the directional plans:

- There were no back builds in either of the long laterals but the trade-off is that this created dead space since there was 375m of vertical section lost from the surface location to the heel.
- Both of the long lateral directional plans incorporated a high kickoff point. This is beneficial because the casing in the tangent is supported by the low side of the hole which helps to minimize helical buckling of the casing when it is put into compression.
- The build section was also limited to a maximum build rate of 6 deg/30m to help limit drag in the lateral. Higher build rates will increase the drag on both the drill pipe while drilling and on the casing while it is being run to Total Depth (TD).

According to the drag charts which can be found in Figures 2.2 and 2.3 that were calculated with WellPlan, if the open hole friction factor was higher than 0.20 the casing was going to cross the helical buckling line. Historically in the Duvernay most casing runs experienced a coefficient of friction in the range of 0.25-0.35 so it was suspected that the casing run would require a casing running tool. Because of this, high torque connections were selected to make it possible to circulate and reciprocate the casing to bottom.

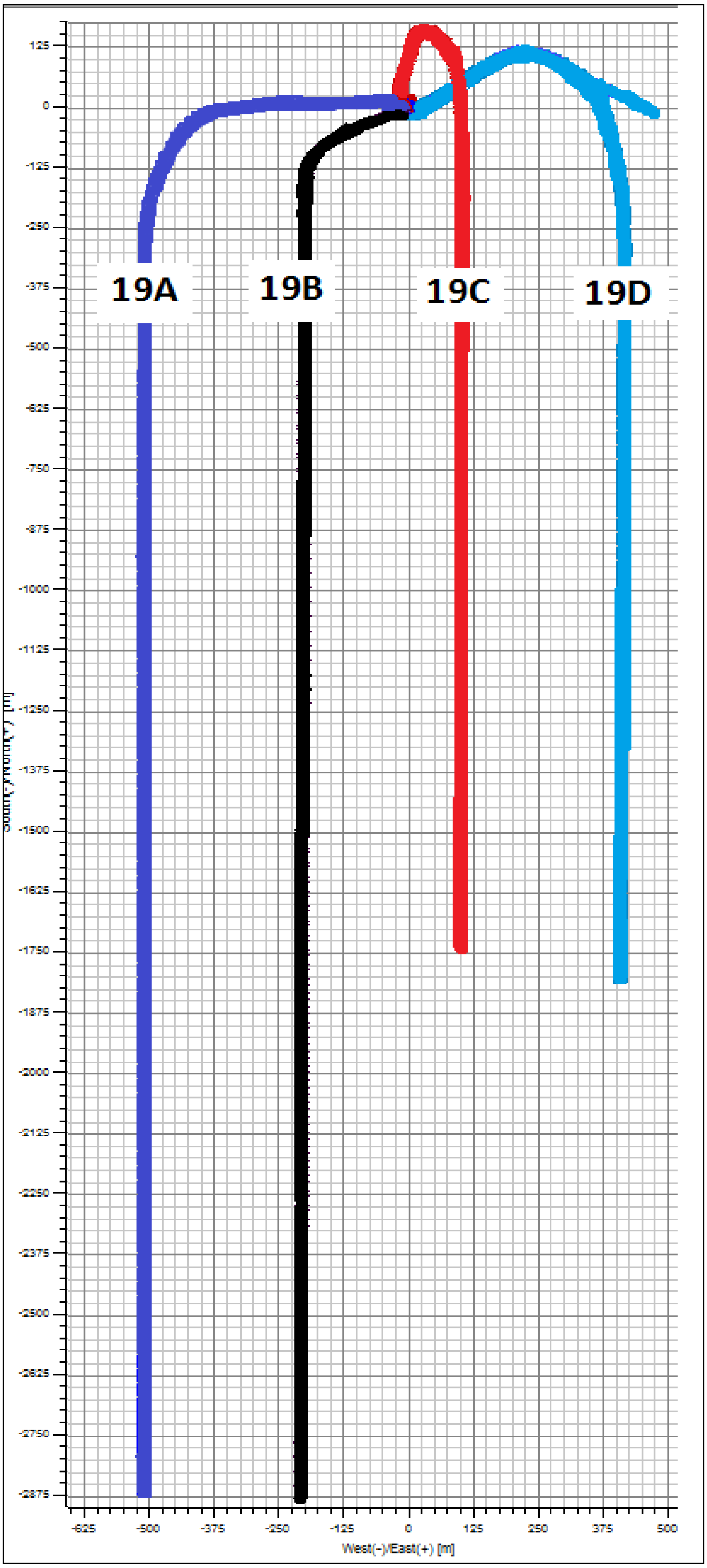

Figure 2.1 Fox Creek 19 Well Trajectories

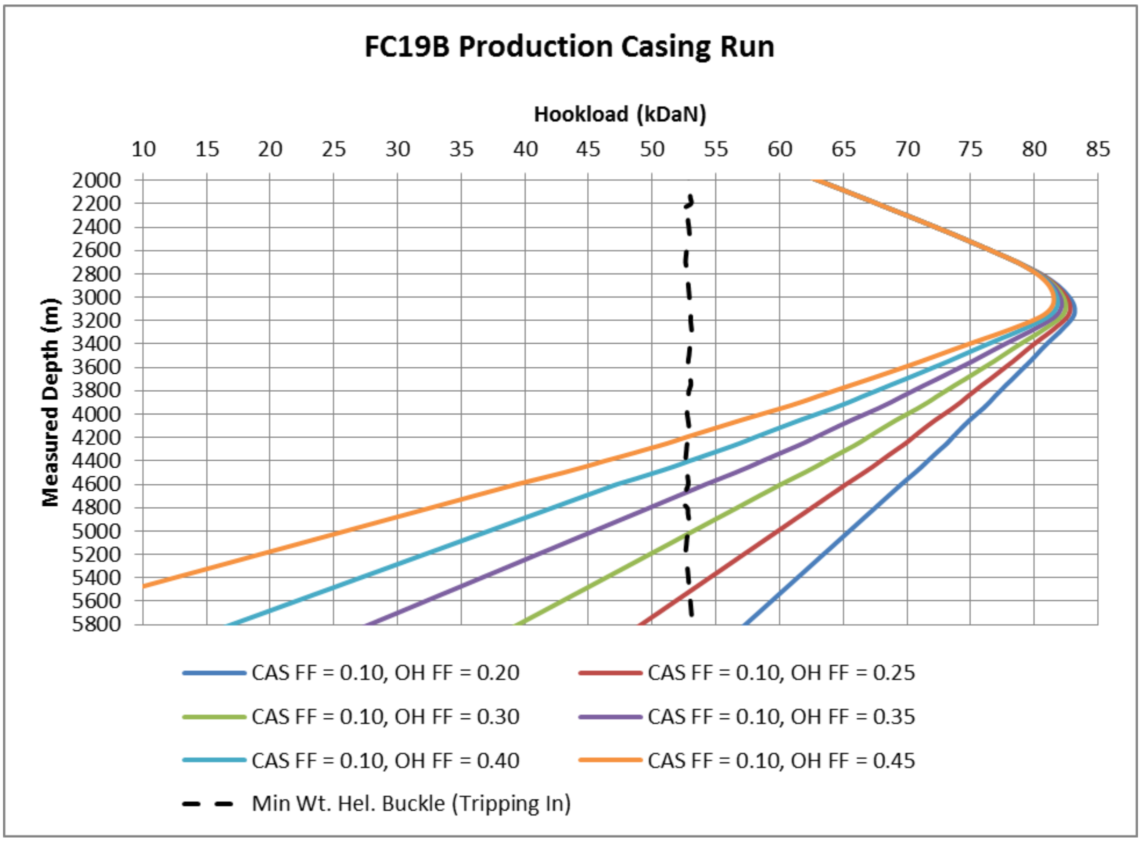

Figure 2.2 Drag Chart - FC19B (5608MD, 1700m KOP, 10 deg tangent)

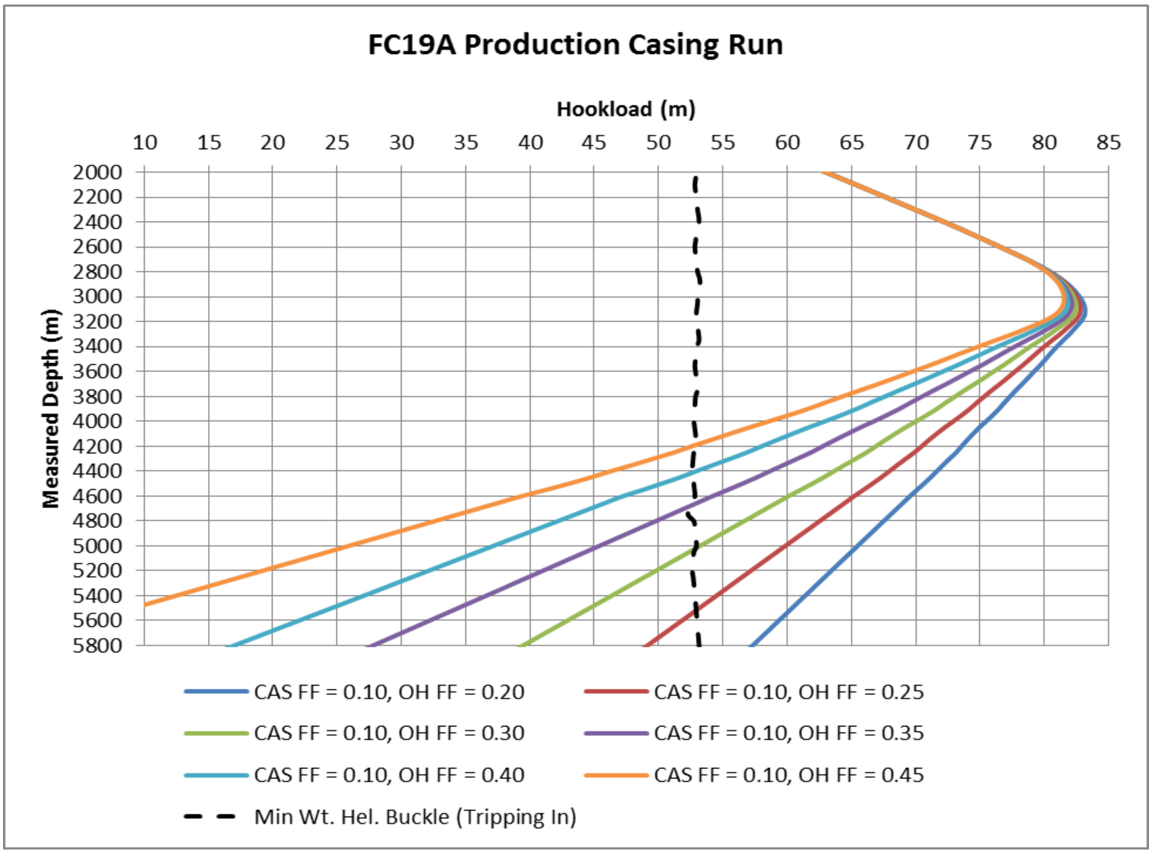

Figure 2.3 Drag Chart - FC19A (5722MD, 1600m KOP, 15 deg Tangent)

2.1.2 Casing Design

The torque and drag models indicate that the casing would reach total depth being run on conventionally on elevators, but a casing running tool (CRT) was planned to be brought to location for the long laterals as a contingency giving the ability to reciprocate and circulate the casing to bottom. The same hole and casing design was used for all 4 wells on the Fox Creek 19 pad.

Table 2.3 – Hole and Casing Design for FC19A

Hole Section	Hole Size	Depths	Casing
Surface Hole	349mm	0m–630mMD	273.1mm 60.27 kg/m K-55, BTC (0 - 630mMD)
Intermediate Hole	251mm	633 – 2671mMD	193.7mm, 53.28kg/m, T95IRP TBlue (0-2671mMD)
Production Hole	165mm	2671mMD – 5722mM	127mm, 34.53kg/m T95IRP TBlue (0-1944mMD) 127mm, 34.53kg/m P-110 VAM SFC (1944-5709mMD)

The intermediate hole was drilled into the Ireton formation which is right above the Duvernay. This covers all of the H2S bearing formations and provides a strong casing shoe prior to drilling into the Duvernay. The Lower Debolt down to the Pekisko have historically been problematic with regard to lost circulation. It is necessary to drill with a mud weight no higher than 1100kg/m3 when those formations are exposed. Given that higher mud weights are required to drill into the Duvernay due to pore pressure and borehole stability in the lateral they must be cased off prior to entering the Duvernay.

The production casing design used for the Fox Creek 19 pad was the standard design used in Fox Creek at the time. FC19B and FC19A were delivered with the maximum lateral length deemed feasible with the current well design. The upper

1944m of the production casing for the wells on the Fox Creek 19 pad was (127mm, 34.53kg/m T95IRP TBlue) due to the risk of H_2S production. Below this point the temperature was over 80 deg C so it was possible to crossover to (127mm, 34.53kg/m P-110 VAM SFC) for the remainder of the well to TD.

The Tenaris TBlue connection was chosen because it is a premium gas tight connection with a maximum make up torque of 13,400 Nm. It is a coupled connection with an outside diameter of 146.2mm which fits inside the intermediate casing. The VAMSFC connection was chosen mainly because of the slim outside diameter (OD) of 131.7mm making it ideal for use in the open hole section due to the tight clearances. This is a high torque premium connection which is gas tight and has a max torque rating of 16,772 Nm. All connections on the production casing string were made up to the maximum make up torque to give the ability to rotate the casing to bottom with the casing running tool.

2.1.3 Lateral BHA Design

For all of the wells on the pad a stabilized bent housing motor assembly was run in the horizontal section to drill the 165mm hole in order to minimize steering. There was a 152.4mm stabilizer on the motor just above the bit, a 158mm stabilizer above the motor, and another 158mm stabilizer located 29.92m back from the bit. It was thought that it would be steerable until total depth, so the decision was made to run this stabilized motor assembly rather than a rotary steerable assembly due to the cost. The motor was a 120.7mm 5/6 lobe 8.3 stage hard rubber motor with a loose fit at surface between the stator rubber and the rotor and it will allow for a maximum differential pressure across the motor of 11,000kpa although the planned differential pressure while drilling will be 5000kpa. While drilling in the lateral the formation temperature is 110 deg C which will cause the stator rubber to expand giving it a proper fit with the rotor. The Measurement While Drilling (MWD) tool in the lateral was a Schlumberger short pulse tool which was able to communicate with surface even at a total depth of 5722mMD.

The drill pipe was 101.6mm 23.36 kg/m S-135 grade with an HT38 tool joint. This is a high torque tool joint with a 123.8 mm tool joint suitable for a 165mm hole. It has a make-up torque of 21,425 Nm and a tensile rating of 203 kDaN which will be sufficient for drilling and tripping out of the hole. The maximum torque seen while drilling to on FC19A was 15,500 Nm and the maximum hook load on the trip out was 110 kDaN so there was sufficient room for torque spikes and over pulls if drilling problems were encountered. Table XX below summarizes the bottom hole assembly (BHA).

Table 2.4 – Duvernay Lateral Bottom Hole Assembly

BHA Description						
Item	Description	ID	OD	Max OD	Length	Cum. Length
1	PDC Bit - TD405S - 5 Blades		165	165	0.20	0.20
2	4 3/4" 5/6 8.3 PDM HR @1.5 W/6" Stab		120	152	8.54	8.74
3	6 1/4" Straight blade Stabilizer	60	121	158	1.48	10.22
4	NM Float Sub	57	120	120	0.83	11.05
5	Short Pulse MWD		120	134	9.45	20.50
6	NM Slick Monel	70	120	120	9.42	29.92
7	6 1/4" Straight blade Stabilizer	60	121	158	1.49	31.41
8	NM Slick Monel	70	120	120	9.49	40.90
9	X/O Sub	0.68	171	207	1.00	41.90
10	Drill Pipe to Surface					

2.1.4 Cement Design

The cement program for all of the wells on the FC19 pad consisted of 1750 kg/m3 cement from the toe up to 1500mMD. There was then 1450kg/m3 spacer left in the annulus from 1500m up to surface. The spacer and cement were pumped at a rate of 1.0m3/min and the top plug was displaced with inhibited water initially at a rate of 0.8m3/min, but the displacement rates were reduced near the end of the job to keep the pressure at the toe below an equivalent circulating density ECD of 2150kg/m3. The fracture gradient of the Duvernay is at an EMW of 2200kg/m3 so it was known that near the end of the cement job there was the risk of inducing losses in the Duvernay. This risk was accepted since cement would already be covering the entire open hole section and would be inside the intermediate casing at this point. As long as the open hole section was properly cemented a low cement top would not require remedial work.

Table 2.5 Fox Creek 19A Displacement Rates During the Production Cement Job

Rate m3/min	Volume m3
0.8	35.0
0.6	5.0
0.4	6.397

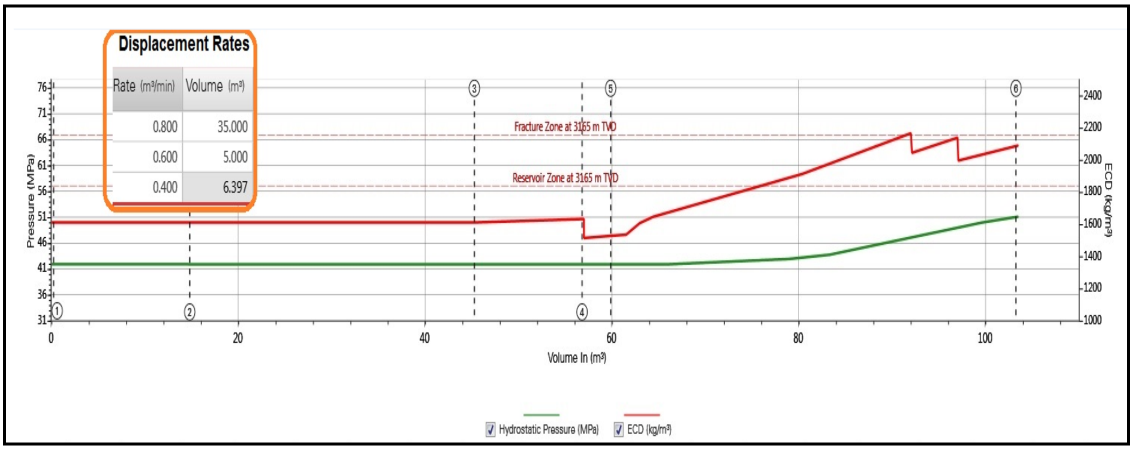

Figure 2.4 Fox Creek 19A ECD at 5722m during Production Cement Job

2.1.5 Rig Specifications

Akita 45 was chosen to drill this pad because it had sufficient performance to deliver the long lateral wells and because it had a walking system allowing it to batch drill the 4 well pad.

Table 2.6 Akita 45 Rig Specifications

Setback Capacity	200,000 daN
Hook Load	300,000 daN
Top Drive Continuous Drilling Torque	4976 daN-m
Blow Out Preventer (BOP)	34,500 kPa
Rig Power	1960 kW
Pump Pressure	29,000 kPa

2.1.6 Production Hole Drilling Fluid

Oil based drilling fluid was run in the production section mainly because it has a lower friction factor in the open hole then a water based system minimizing drag. Oil based fluid also has higher inhibition than most water based systems, therefore improving borehole stability in the Ireton and Duvernay which are both shale formation.

Table 2.7 Drilling Fluid Properties - Fox Creek 19 Production Hole

System:	Versadrill DrillSol
Density:	1350 kg/m^3
Viscosity:	55-70sec/l
YP:	5-7PA
6RPM:	6 - 9
PV:	ALARP
Cl:	30% ~260,000 mg/L
Lime:	15-20 kg/m^3
Oil Water Ratio:	90:10

2.1.7 Clean Up Cycles at TD and Friction Reduction Pill

Once at total depth the plan is to conduct clean up cycles pumping at 1.0m3/min and rotating at 120 RPM in order to clean all of the cuttings out of the horizontal section of the hole. Once the hole is clean, a friction reducer pill is spotted in the lateral prior to tripping out of hole from TD. The friction reduction pill consists of 21kg/m3 of walnut medium and 12kg/m3 of graphite and is spotted only in the lateral from TD to Heel.

2.2 Duvernay Long Lateral Drilling Results

The surface and intermediate hole sections on this pad were standard for the field at the time. There were problems encountered, but they were unrelated to the long lateral trial so they are outside the scope of this thesis. The production sections on FC19D and FC19C were drilled with a 1330kg/m3 mud weight successfully to TD. Neither of these wells had any problems with drag in the lateral or borehole instability. Both of these wells were able to run the production casing successfully to TD on elevators so it was anticipated at the time that there would be no issues executing the longer laterals.

2.2.1 Fox Creek 19B Production Section Results

The horizontal section on FC19B was drilled with a 1330kg/m3 mud weight and a bent housing motor set at 1.5 deg which was the same as the previous 2 wells, but FC19B had a large amount of drag which was not seen previously. On every connection the rig would work the stand up and down to determine the friction factor in the lateral. When drilling the lateral section to 3600mMD the drill pipe was being rotated at 100RPM from surface, the pump rate was at 1.1m3/min and the ROP was as fast as 60m/hr. It was seen that the friction factor was slowly increasing getting up to a value of 0.35 which indicated that the cuttings in the lateral were not being properly cleaned. The decision was made to increase the rotary speed to 120RPM to assist with hole cleaning. Increasing the RPM did help reduce the friction factor, but it began to increase again when we got to 4000mMD. From 4000mMD to 4700mMD the ROP was limited to 40m/hr to reduce the cuttings being generated so that proper hole cleaning can be achieved. At 4700m drilling was stopped because of the high drag and 2 bottoms up pumping at 1.1m3/min and rotating at 120RPM were made in order to help clean the hole before continuing to drill. From 4700m until TD at 5608m the pump rate needed to be reduced to 1.0m3/min due to pump pressure limitations of the rig and the ROP was limited to 30m/hr to assist with hole cleaning. TD was reached successfully, but it became increasingly difficult to steer while drilling further out in the lateral.

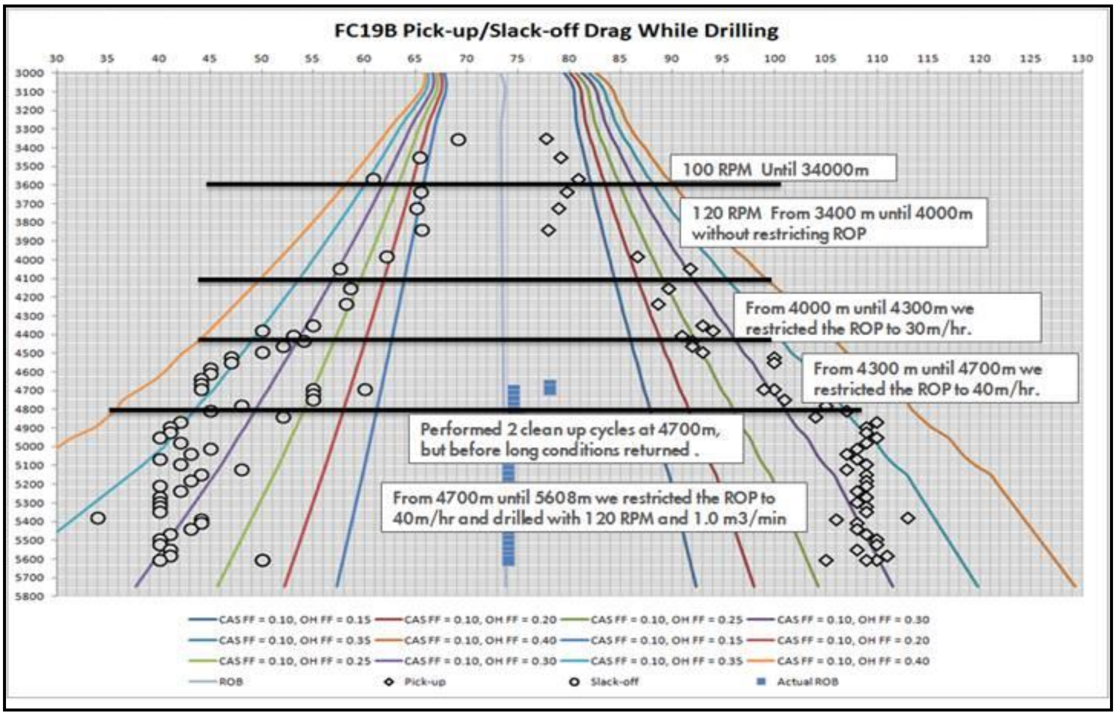

Figure 2.5 Drag on FC19B While Drilling the Production Section

At TD the hole was cleaned by pumping at 1.0m3/min and rotating at 120RPM for 18 hours. Once there were no more cuttings coming over the shakers indicating the hole was clean a friction reducing pill consisting of graphite and walnut shells was placed in the lateral prior to tripping out of hole. On the trip out of the hole a 0.3 open hole friction factor was encountered. On FC 19D and FC 19C while tripping out of the hole with the same BHA only 0.15 open hole friction factor was encountered. According to the modeling a 0.3 friction factor was still sufficient to run casing to bottom, but a Volant casing running tool was ready on location as a contingency.

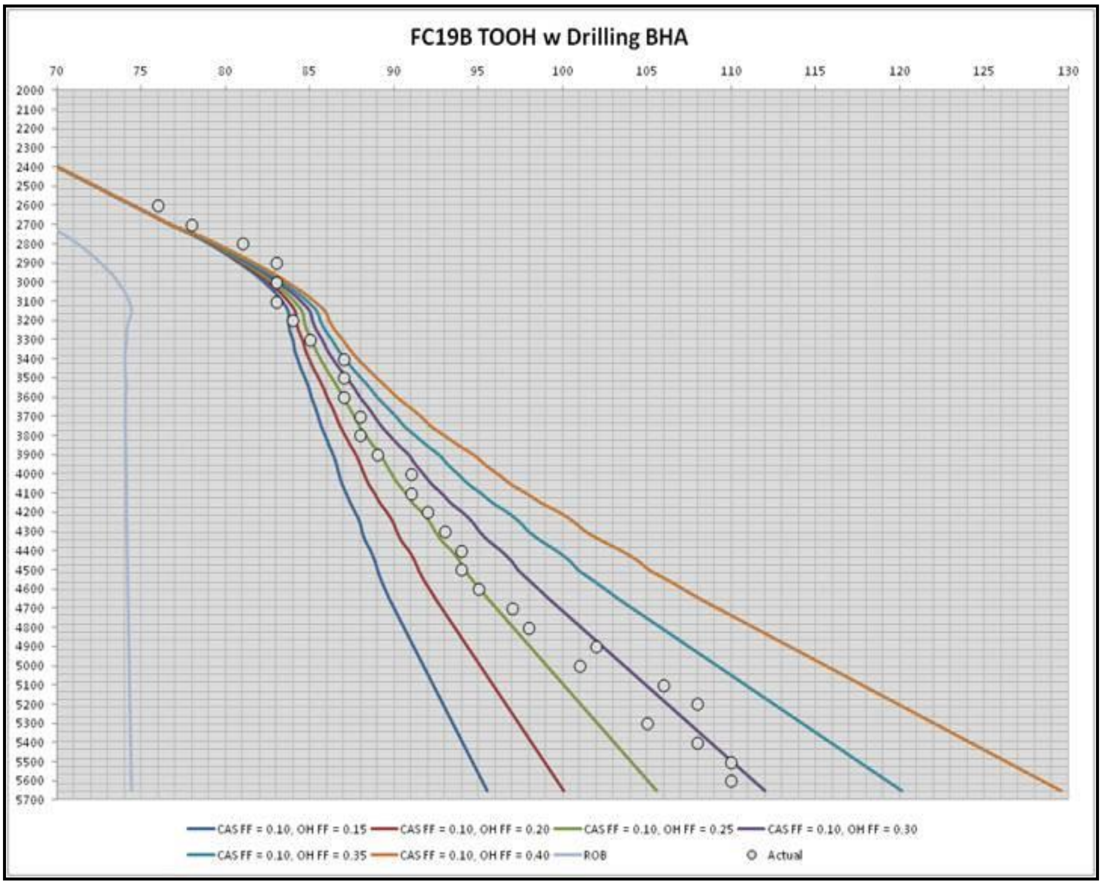

Figure 2.6 Drag on FC19B While Tripping out of Hole

The casing was run on elevators to a depth of 4980m before rigging in the Volant casing running tool (CRT), but it can be seen that there was a 0.55 open hole friction which was substantially higher than before. From 4300m to 4980m it can be seen on the drag chart that slacking off fully on the casing string and working it in on every connection, still the casing was experiencing helical buckling in the vertical section making it difficult to continue running. From 4980mMD to TD at 5608mMD it was necessary to circulate and rotate the casing to bottom using the CRT. At TD the production hanger was landed and the cement job was performed successfully.

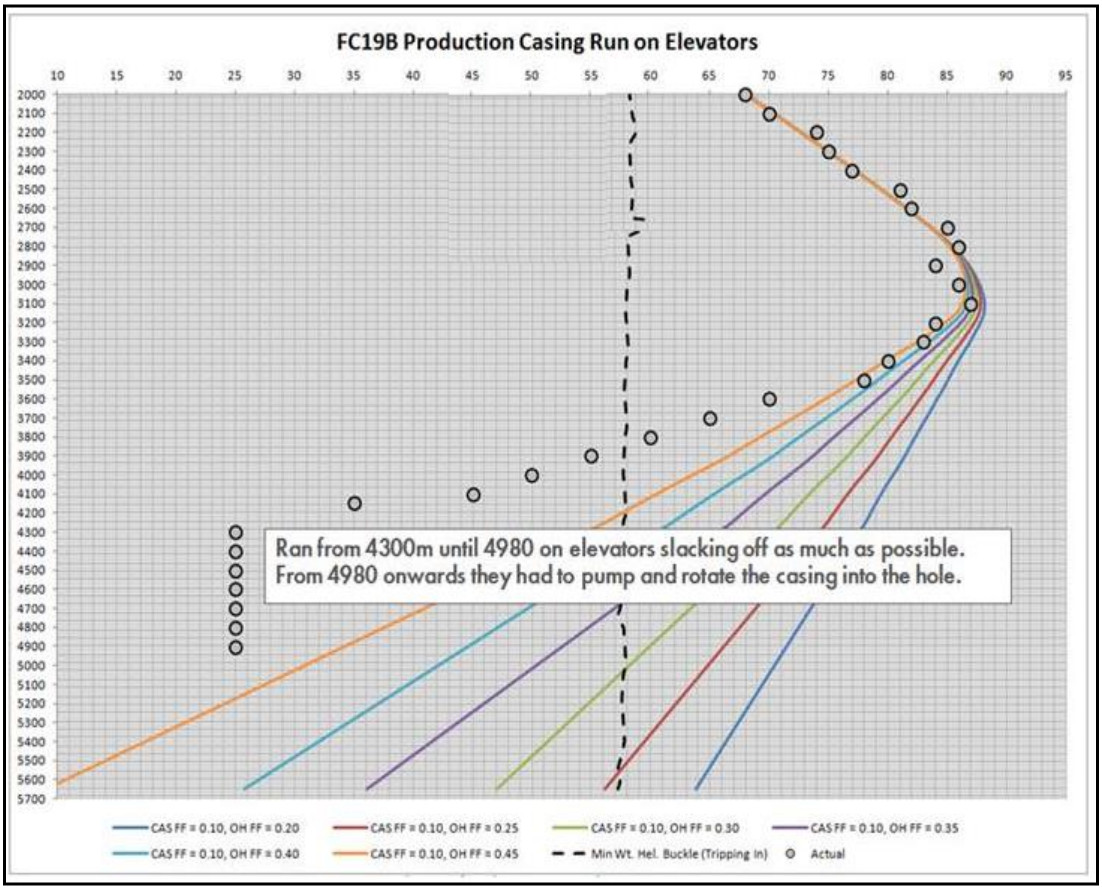

Figure 2.7 Drag on FC19B While Running Production Casing

The best explanation for the high torque and drag is borehole stability problems. In the lateral when the ROP was limited, rotating at 120 RPM, sliding 2% and pumping at 1.0 m3/min it was still not possible keep the hole clean. With those parameters there are not enough cuttings being created to cause a problem which indicated that additional solids were entering the well from instability issues.

The mud properties were very similar for all 3 wells which had been drilled on the pad at this point. They were all drilled with a 1330 kg/m3 mud weight, however FC 19B had much higher gas units while drilling and much more trip gas was seen while running the casing. It is thought that this contributed to the reduction in hole stability. After the results on FC19B it was decided to increase the mud weight to 1400kg/m3 for the lateral section on FC19A to help maintain better hole stability in the lateral and minimize the gas seen at surface.

2.2.2 Fox Creek 19A Production Section Results

Due to the instability problems seen on FC19B the mud weight was increased to 1400kg/m3 for the production section on FC19A. The borehole stability was better in the lateral than on FC19B, but the drag was still higher than most wells in the field. The ROP was limited to 40m/hr throughout the lateral and the pipe was rotated at 120RPM to help with wellbore cleaning. At 4450mMD drilling was stopped to circulate 2 bottoms up pumping at 1.1m3/min and rotating at 120RPM because the drag had gotten up to a friction factor of 0.4 in the lateral.

For the final 500m of the well the rig was very pressure limited due to the long lateral, the 4” drill pipe and the 1400kg/m3 mud weight. Normally the pop-vales are set at 28MPA which is 80% of the 34.5MPA pressure rating of the standpipe, but a waiver was signed allowing us to increase that to 31MPA which is 90% of the standpipe rating. Even with the higher pressure rating the flow rate needed to be reduced to 0.9m3/min. On future long lateral wells having 4.5” drill pipe and a rig with higher pump pressure would allow for substantially improved drilling performance in the lateral.

At 5500mMD it was no longer possible to steer due to drag in the wellbore, the rotary mode was necessary to reach TD at 5722m. The bit was tracking well in the formation with only 3% slides in the entire lateral which is much better than the 10-15% normally encountered. Even without the ability to steer in the last 222m staying in the desired zone was possible.

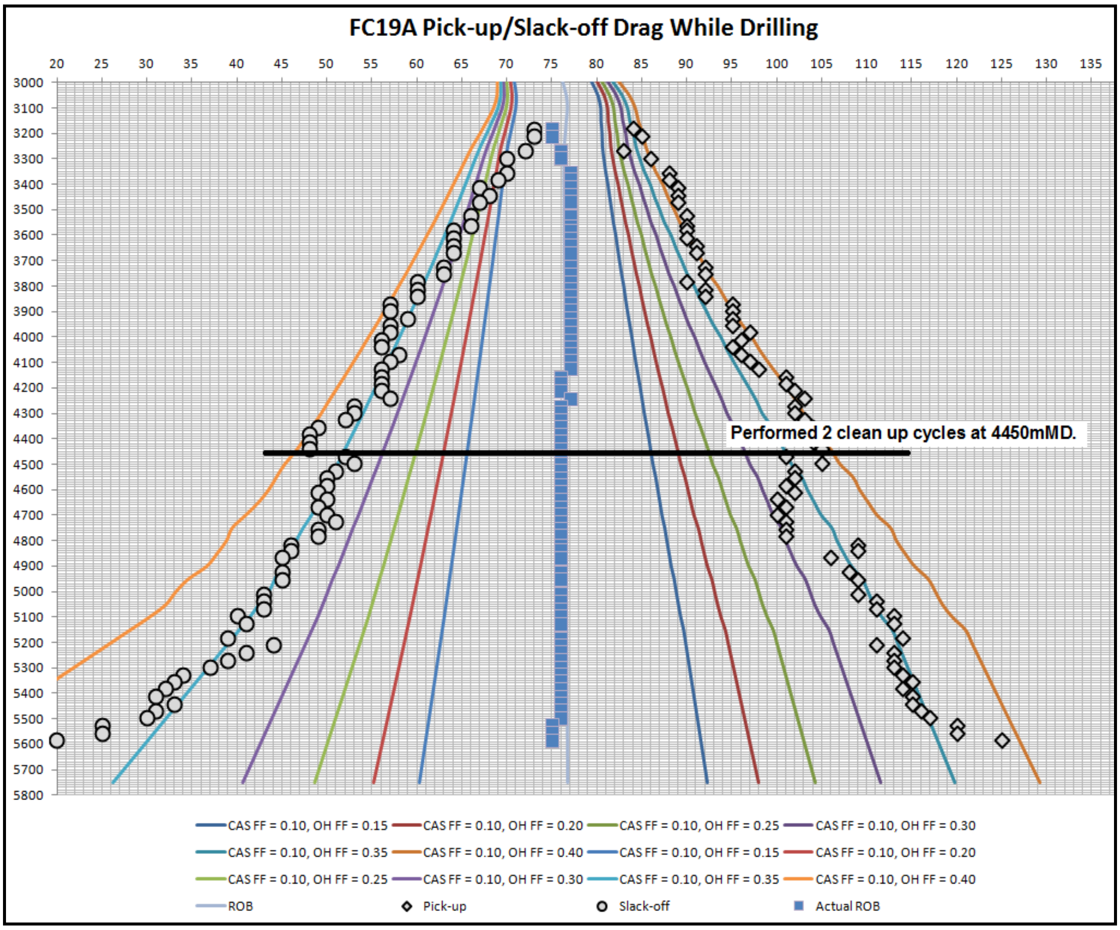

Figure 2.8 Drag on FC19A While Drilling the Production Section

At TD the hole was cleaned by pumping at 1.0m3/min and rotating at 120 RPM for 20 hours until the hole was fully clean and on the trip out of the hole a 0.3 open hole friction factor was observed which was very similar to FC19B.

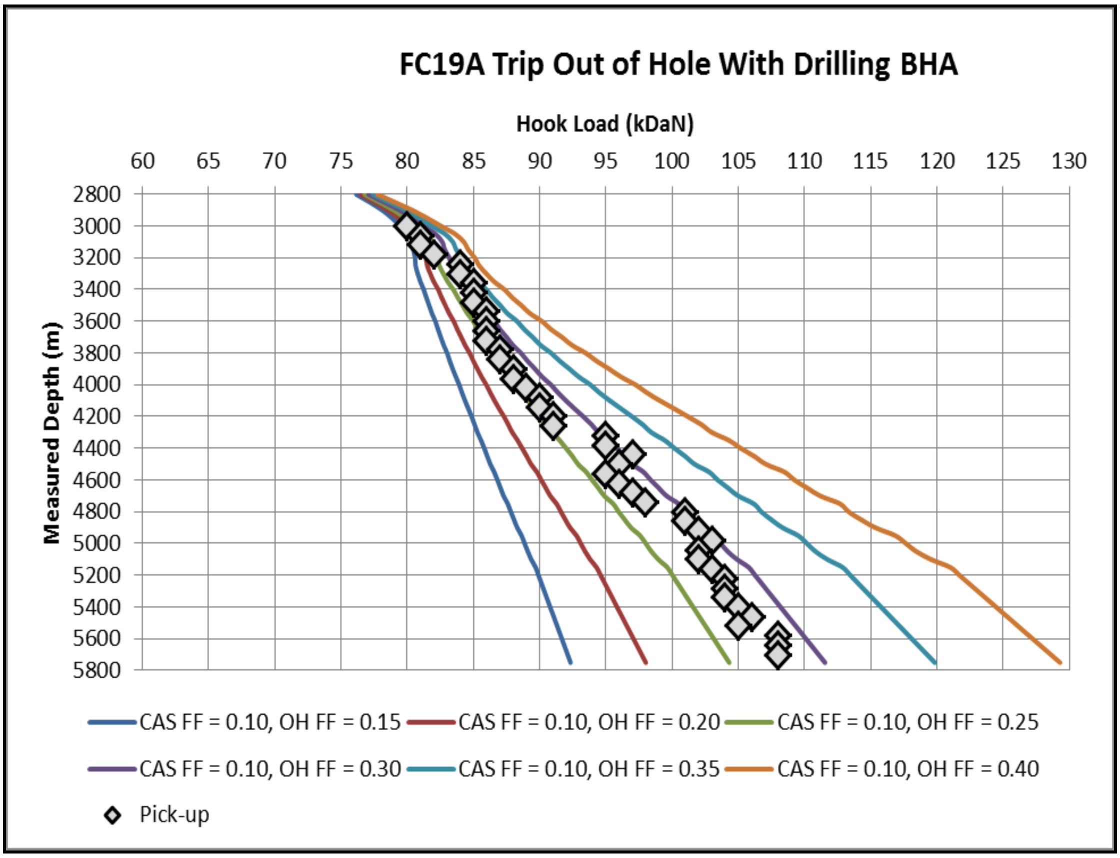

Figure 2.9 Drag on FC19A While Tripping out of Hole

The casing was run on elevators to a depth of 5508mMD experiencing a 0.45 open hole friction factor which was better then what was seen on FC19B indicating that the hole was in better condition because of the heavier 1400kg/m3 drilling fluid used in the lateral. At 5508m a casing running tool was rigged in order to circulate and rotate the casing to bottom. At total depth of 5722mMD there was not free range of motion without the CRT so it was not possible to land the casing hanger which was achievable on FC19B. It was necessary to use the CRT to get the casing to TD. After performing the cement job emergency slips were set through the BOP into the wellhead and were pressure tested successfully.

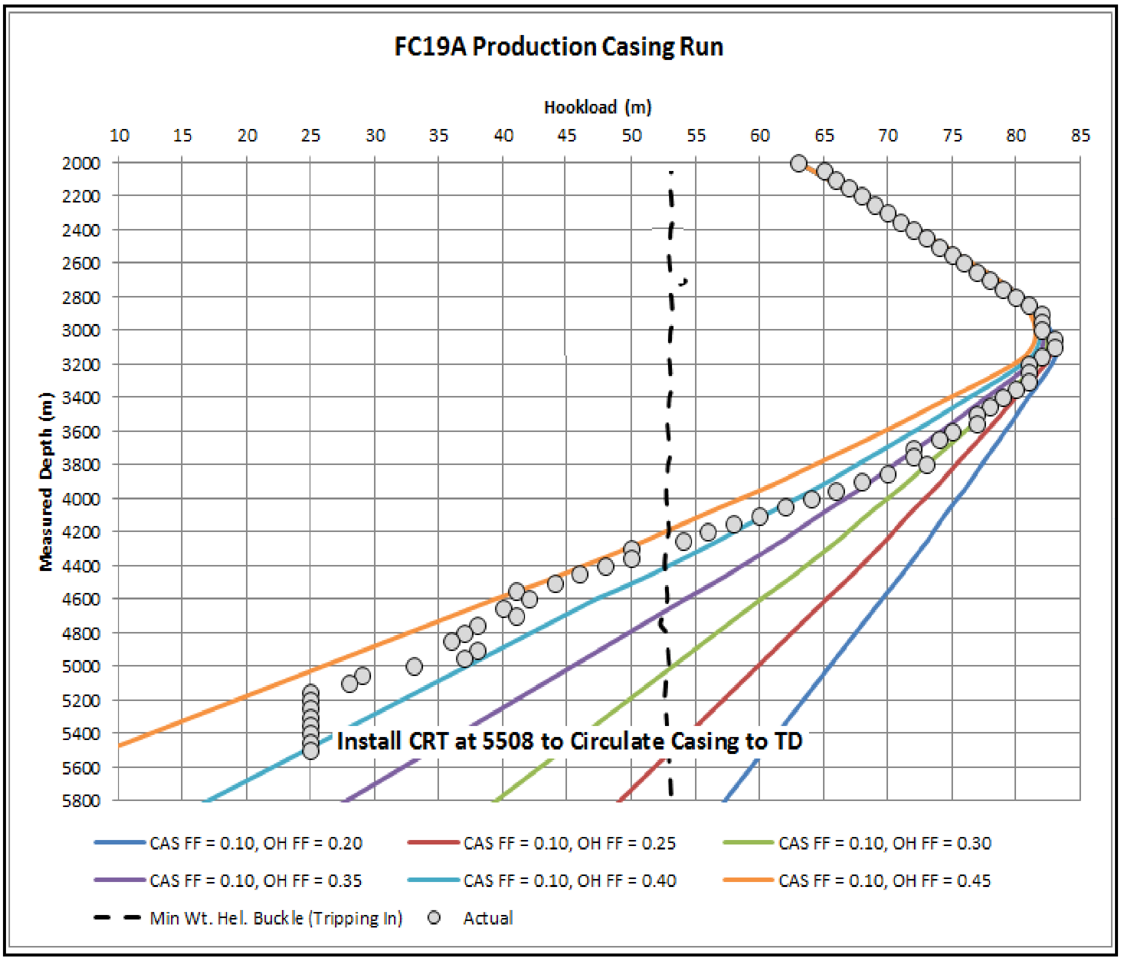

Figure 2.10 Drag on FC19A While Running Production Casing

2.3 Duvernay Long Lateral Look Back and Recommendations

2.3.1 Directional Plan

FC19A and FC19B had kick off points of 1600m and 1700m respectively and both of their casing runs failed to reach TD without the use of a casing running tool due to helical buckling. On future long lateral wells it would be beneficial to have a higher kick off point (KOP) and a longer tangent section in the upper wellbore to prevent helical buckling during the production casing run.

2.3.2 Drilling Assembly Selection

The long laterals on this pad were at the absolute limit of what could be drilled with a traditional bent housing assembly. Running a Rotary Steerable System (RSS) on all wells which have a lateral length in excess of 2000m would give the ability to steer in the lateral. The performance improvements that an RSS will provide especially further out in the lateral offset the added cost. On FC19A had it not been for the bit naturally tracking in the formation delivery of the planned lateral would not been possible. RSS also has the benefit of maintaining a straighter lateral hole section.

2.3.3 Drill Pipe Selection

It would be beneficial to run 4.5” DP for the production hole section on all future Duvernay wells rather than 4.0” regardless of lateral reach. This will give improved hydraulics allowing higher pump rates with less pressure at surface. On FC19A when drilling with the 1400kg/m3 mud it was necessary to reduce the pump rate to 0.9m3/min because of pressure limitations at surface. At any given rump rate 4.5” DP would increase the annular fluid velocity improving hole cleaning. Finally larger DP in a long well will have less stick slip downhole and this will improve drilling performance and reduce the chances of a bit or downhole tool failure.

2.3.4 Casing Selection

FC19A was at the absolute limit of what was deliverable with the current casing design. Laterals beyond the reach of FC19A could utilize a tapered casing string allowing for heavier casing in the vertical to act as push pipe and lighter casing in the lateral which would reduce the drag force. They could also utilize casing floatation to extend the lateral reach even further.

2.3.5 Drilling Rig Selection

The main limitation when drilling the long wells was pump pressure. It was necessary to get a waiver from the drilling contractor to increase the maximum pump pressure from the recommended 29MPA up to 31MPA just to finish the wells. It was also necessary to reduce the pump rate while drilling to 0.9m3/min due to pressure limitations. This caused a decrease drilling performance as well as hole cleaning increasing the torque and drag in the lateral. On future wells with a lateral length beyond 2000m it would be beneficial to have a rig which is rated to a higher pump pressure.

Chapter 3

3. Groundbirch Long Lateral Trial in the Montney Formation

The Groundbirch long lateral trial was done by Shell in the Sunset area of the Groundbirch asset. The information from this trial is based on the “End of Well Report for 11-09-79-18 Long Lateral Trials” which was written by Travis Woodward. Of the 11 wells drilled into the Montney formation between March and October 2013, six wells were drilled to a standard lateral length of ~2200m, and five wells were drilled with a lateral length of ~3600m. Many of the lessons from this pad can be implemented in the Duvernay formation to allow for longer laterals in the future.

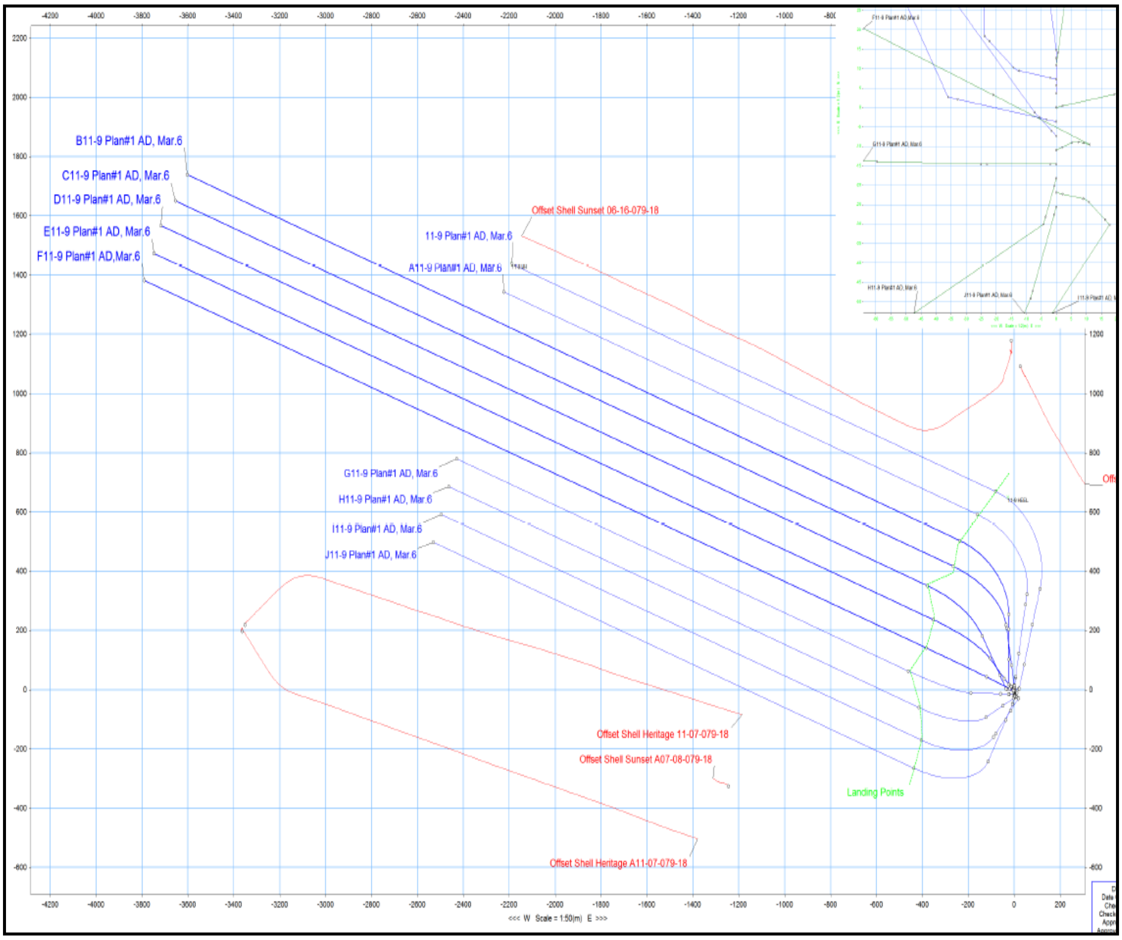

Figure 3.1 Plot of 11 Wells on the 11-9-79-18W6 Pad, Including Five Long Laterals

3.1 Groundbirch Well Design

The well structure for two example wells from the 11-9 pad can be found below. Table 3.1 is a sample of a well with a normal 2200m lateral length, whereas Table 3.2 features information from a well with an extended 3600m lateral length. The hole size on the normal length well is a consistent 200mm monobore with 139.7 production casing from surface to TD. The long lateral design tapers from 216mm to 200mm at the heel. The long laterals feature a casing design which tapers from 177.8mm to 139.7mm in order to have the larger casing in the vertical section of the well to assist in pushing the smaller lighter casing through the long lateral section.

Table 3.1 Well Design for a 2200m Lateral on 11-9

Hole Section	Hole Size	Depths	Casing
Surface hole	311mm	0m - 620m MD	244.5mm 59.53 kg/m L-80, LTC
Main Hole	200mm	0m -4691m	139.7mm 29.76 kg/m P110 VAMTOP HT (Surface →Heel at 2481mMD) 139.7mm 29.76 kg/m P110 LTC 2481mMD → TD at 4691mMD

Table 3.2 Well Design for a 3600m Lateral on 11-9

Hole Section	Hole Size	Depths	Casing
Surface hole	311mm	0m - 615m MD	244.5mm 69.69 kg/m L-80, LTC
Main Hole	216mm	0-2668m	177mm 56.5 kg/m P110 VAMTOP HT 0m → 90^0 Lateral
	200mm	2668m-6268m	139.7mm 29.76 kg/m P110 VAMTOP HT R3 Seamless 90^0 Lateral → TD

3.2 Groundbirch Long Lateral Look Back and Recommendations

3.2.1 Pump Pressure

While drilling the long lateral wells pump pressure was a limiting factor which held back the drilling performance in the lateral. The ideal rig to drill these laterals would have a 7500 psi pressure rating allowing for increased drilling distance.

3.2.2 Drill Pipe Selection and Make-Up Torque

The drill pipe chosen for this trial was 5" 19.5# with a DS50 connection. The max make up torque for this connection is 39000ft-lbs, but for this well the connection was being made up to the optimum torque of 36000ft-lbs. The torque while drilling near TD was 30000-32000ft-lbs which exceeded 80% of the make-up torque used presenting a risk of backing off the drill pipe downhole. In the future this connection should be made up to the maximum make up torque.

3.2.3 Rotary Steerable Drilling Assembly

A Rotary Steerable System (RSS) was run for drilling the 3600m lateral section on the long laterals. It was determined that it would not be possible to steer all the way to TD with a bent housing motor assembly, so an RSS system was selected. Another advantage of running a RSS system in the lateral is that it is possible to drill a straighter lateral without the micro doglegs created when sliding to steer with a bent housing motor. On all of the long lateral wells where RSS was used the friction factor on the trip out of the hole was found to be 0.20 in the lateral section. This was considered to be a low friction factor in Groundbirch as it is more typical to see friction factors on the trip out between 0.25-0.30. This reduction in friction factor from the RSS will help enable the casing to be run to a greater depth.

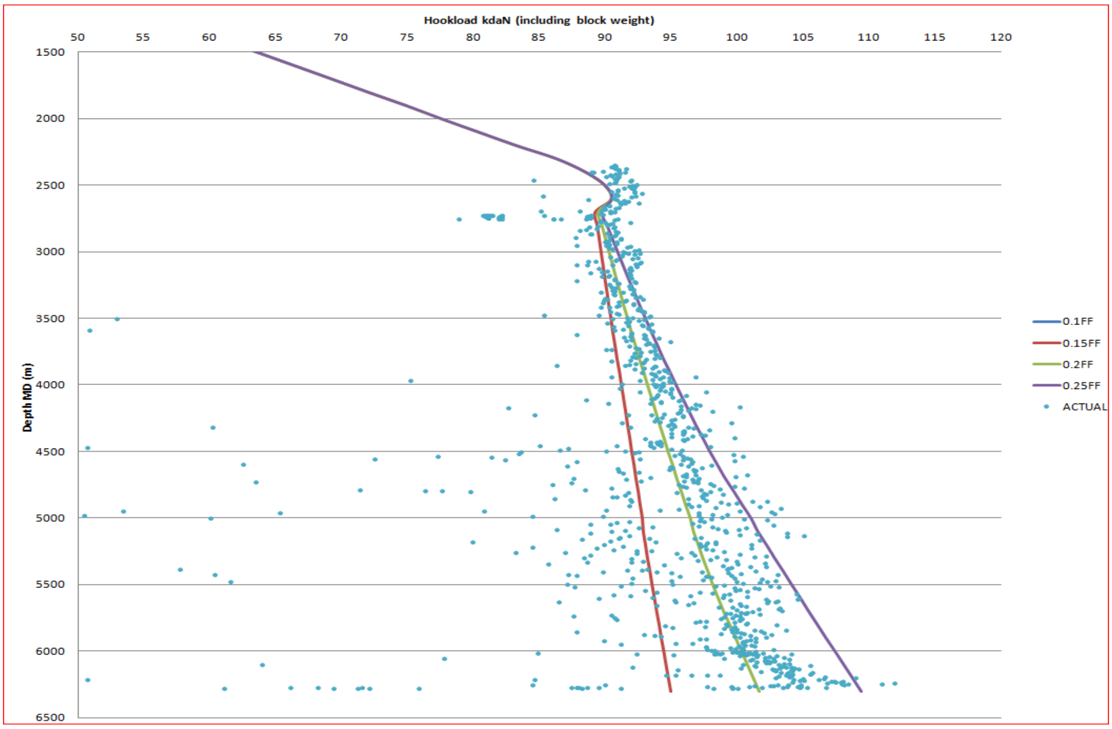

Figure 3.2 F11-9 Drag Chart for Pulling Out of Hole at TD on 3600m Lateral

In order to minimize stick slip at the bit it was necessary to rotate at 200 RPM from surface, but due to the torque limitations of the drill pipe and the top drive, the on bottom performance was limited when reaching TD. On future wells when running RSS a motor should be run above the RSS to achieve higher rpm at the bit while rotating the drill pipe from surface at 120 RPM. This would reduce the torque at surface while giving a higher RPM at the bit improving the ROP and reducing stick slip.

3.2.4 Casing Floatation for Production Casing Running

Casing floatation was utilized for the long laterals and allowed for smooth casing running operation on all five wells. Each well had approximately 2500m of air filled pipe which was chosen as a balance to reduce drag, eliminate casing buckling and minimize the air chamber. The justification for using casing floatation technology was to eliminate helical buckling which causes casing lockup when running conventionally. The figure below shows conventional running (green line) vs. various amounts of air filled casing. The second reason for using casing floatation was that if the casing string had to be pulled while full of drilling fluid, the model suggested that it would not be possible to pull it from TD. The string weight plus drag exceeded the rig hoisting limit of 180kdaN while running casing. However, with air in the casing the string could be safely pulled from TD assuming the floatation collar had not been opened.

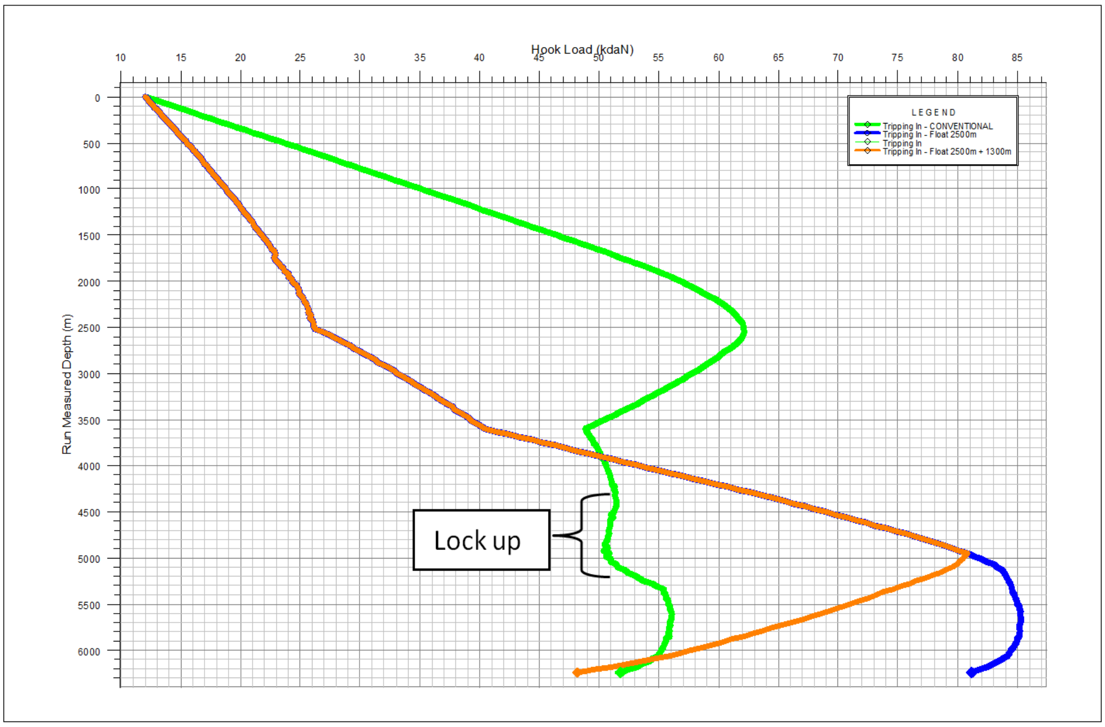

Figure 3.3 Drag Chart for Conventional Casing Running Versus Floatation

For all five wells, landing weights were in excess of 70kdaN. This suggests that it would have been possible to run the production casing significantly further than the 3600m lateral length. Typical friction factors for running casing in

Groundbirch are around 0.36 for a traditional casing string without floatation. It can be seen in the following figures that friction factors for the floated casing are approximately 0.48, which is significantly higher than standard non floated wells. It should be noted that despite the higher friction factor the hooklod line shape changes drastically because of casing floatation. This is believed to be caused by the buoyancy effects being higher when casing is floated then what was reflected in the WellPlan drag model. It is therefore recommended when modeling floating casing running in WellPlan that an additional 25% is added to the friction factor when comparing with standard friction factors in the field. This appears to be a significant increase, however the benefits of the casingfloatation itself offset the negative effects of the increased friction factor at these lengths. Future longer reach laterals could move the floatation collar up to the heel inorder to further reduce the drag experienced in the lateral allowing the casing to be run even further.

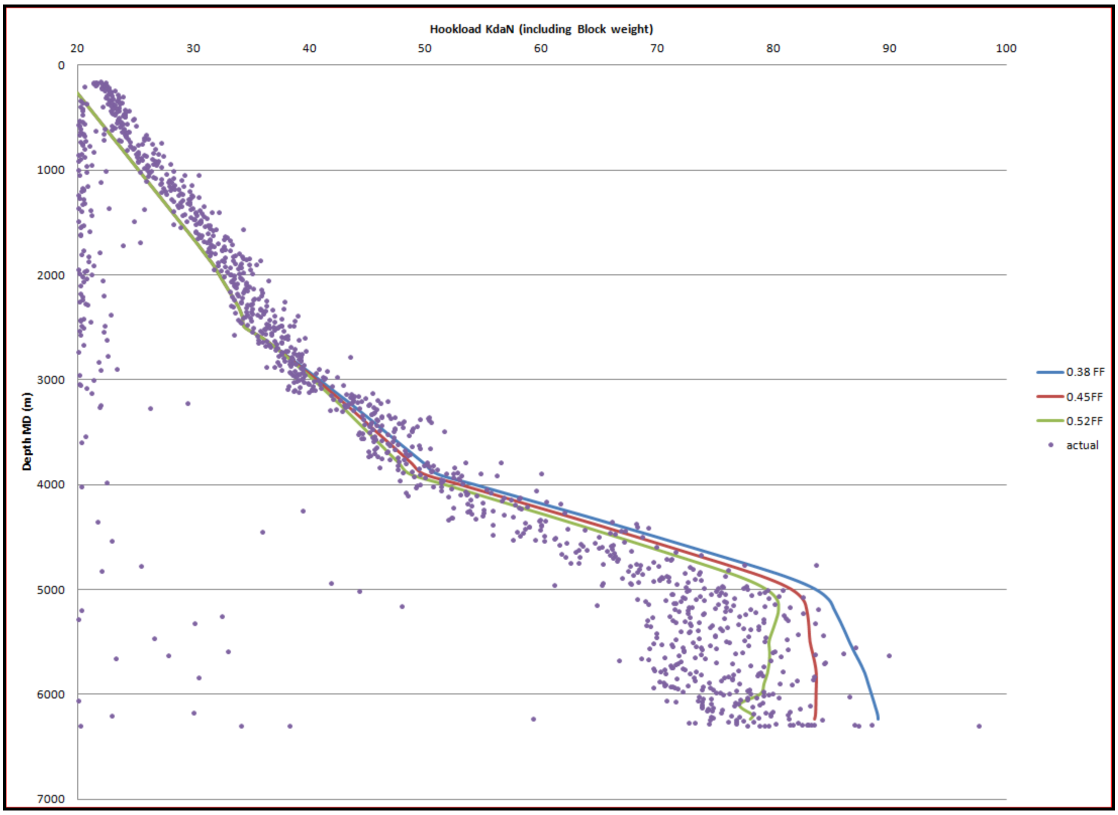

Figure 3.4 Drag Chart for F11-9 When Running Production Casing to TD

3.2.5 Casing Crossover Design and Placement

The first three long lateral wells had the 177.8mm by 139.7mm cross over placed at 90deg. The reason for this was that the 216mm hole was drilled to 90deg so that the RSS could be run in and drill horizontally. The added benefit of placing the crossover at 90deg was to maximize the amount of the 7” casing in the vertical portion of the wellbore to help push the casing to TD. The fourth and fifth wells had the crossover placed at 60deg and 40deg respectively because the landing weights had been high enough on the previous three wells that it was seen an acceptable risk to reduce the amount of 177.8mm casing and still get the casing string to bottom. Future wells drilled with this design could raise the crossover further, or depending on lateral length eliminate the tapered design all together and run the floatation collar on an all 139.7mm monobore design.

3.2.6 Groundbirch Long Lateral Cement Job

The critical success factors for cementing were the following:

- Cement the casing within the pressure restrictions
- Cement returns to surface
- No compromise in cement job quality as per CBL evaluation performed by completions
- Provide completions the ability to effectively fracture the wellbore

Due to the long length of the well, cementing pressure were a significant concern for the job. The two driving pressure limitations were pump pressure/cement head rating (56MPA) and frac break down of the formation at

63MPA. When pumping the Groundbirch standard blends at weights of 1750kg/m3 lead and 1900kg/m3 tail with a 1000kg/m3 displacement fluid, the modeling showed pressure limits were significantly exceeded. Through a number of iterations the final cement blends of a 1550kg/m3 lead and 1700kg/m3 tail were chosen, keeping the fresh water displacement fluid. With the lighter blends, ECD and surface pressure were reduced, keeping them within the operating envelope. Figure 3.5 demonstrates the modeled pressure during the cement job.

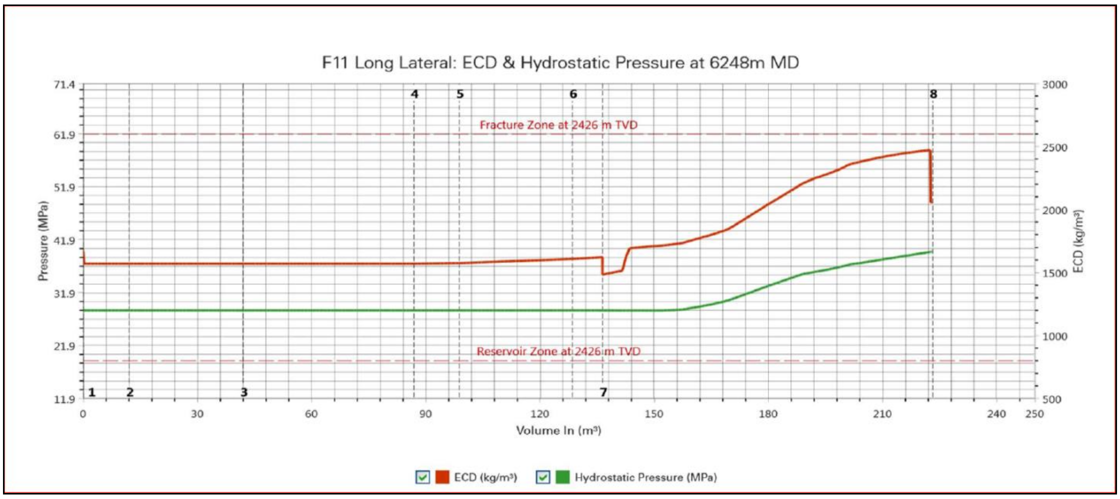

Figure 3.5 Model of Bottom Hole Pressure During the Production Cement Job

Cement returns on all 5 long laterals were all in the 10-14m3 range, which was roughly what the model and percent excess predicted. This suggested that there was proper flow in the well without excessive channeling, or breaking down the wellbore due to excessive ECD pressures downhole. A Cement Bond Log (CBL) was run on the C11-9 well and it showed a good cement bond. Completions had no issues fracturing the wellbore which suggests good isolation in the horizontal preventing channeling in the annulus.

Chapter 4

4. Future Duvernay Long Laterals

The future Duvernay well design concepts will focus on the Swift region of Shells acreage which has been moved into development. There are different regions of the field with different production type curves, pressure regimes and geological properties, however this thesis will focus on the design for Shells core development acreage located in T62 R19 W5M. This region of the field has been de-risked for H2S production from the Duvernay. The intermediate casing string will cover all H2S bearing formations so the production casing string will not need to be designed for H2S exposure.

The grade of the production casing string will vary across the Duvernay field depending on the presence of H_2S, however remainder of the well design features can remain constant across the Duverany with adjustments to the directional plans to account for variations in the total vertical depth of the Duvernay. The key enablers for delivering long laterals are optimized directional plans, drill pipe and BHA design, drilling fluid design, friction reduction pills, casing floatation and tapered production casing strings. It is also a requirement to have a drilling rig with sufficient hook load, torque and pump pressure to meet the requirements of each design concept. These key design enablers could also be implemented in other unconventional oil and gas fields in order to drill longer laterals.

4.1 Future Duvernay Long Lateral Common Design Elements

4.1.1 Directional Plan

The most challenging well on every pad will be the outer most well which has a 700m lateral step out, and this is the well which each design concept will focus on. The directional plan will remain consistent down to the heel with an optimized trajectory to minimize torque and drag while drilling and running casing for all lateral length design concepts. This design incorporates an early kickoff point at 50mMD where it will build to an inclination of 3 deg with an azimuth of 90 deg in order to achieve with the 700m lateral step out and to support the drill pipe and casing on the low side of the hole to minimize helical buckling. This 3 degree tangent section will be held from 100m down to 1600m. From 1600m to 1930m it will build inclination at 2 deg/30m in order to reach an inclination of 25 deg maintaining an azimuth of 90 deg. The 25 deg tangent will be held from 1930mMD until 2860mMD. The well will build from 25deg inc and 90 deg az to land at 90 deg inc and 180 deg az 2860mMD to 3374mMD with a smooth 5.247deg/30m build rate. Keeping the build rates low in the build section is critical for minimizing drag in the lateral. A summary of the trajectory is in table X-X below. The lateral section for each design will hold a constant 90 deg inclination and 180 deg azimuth from the heel until TD.

Table 4.1 Directional Plan on Future Duvernay Long Laterals

MD (m)	CL (m)	Inc (°)	Azi (°)	TVD (m)	North/South (m)	East/West (m)	Dogleg (°/30m)
0		0	0	0	0	0	0
50	50	0	0	50	0	0	0
100	50	3	90	99.98	0	1.31	1.8
1600	1500	3	90	1597.92	0	79.81	0
1930	330	25	90	1916.16	0	159.16	2
2860	930	25	90	2755.55	0	559.53	0
3374.6	514.6	90	180	3050	-327.61	700	5.247

4.1.2 Drilling Fluid

Oil based drilling fluid will run in the production section mainly because it has a lower friction factor in the open hole then a water based system minimizing drag. Oil based fluid also has higher inhibition than most water based systems improving borehole stability in the Ireton and Duvernay which are both shale formation. The planned density will be 1400kg/m3 because it will aid in maintaining borehole stability. On the FC19 long lateral pad a 1350kg/m3 drilling fluid was initially run, and it was seen that borehole quality improved when it was increased to 1400kg/m3. This same drilling fluid will be used for all of the hydraulic analysis for all the different lateral length development scenarios.

Table 4.2 Drilling Fluid Properties for Future Duvernay Long Laterals

System:	Versadrill DrillSol
Density:	1400 kg/m^3
Viscosity:	55-70sec/l
YP:	5-7PA
6RPM:	6 - 9
PV:	ALARP
Cl:	30% ~260,000 mg/L
Lime:	15-20 kg/m^3
Oil Water Ratio:	85:15

4.1.3 Clean Up Cycles at TD and Friction Reduction Pill

Once at total depth on all lateral length concepts the hole will be cleaned by pumping at maximum allowable rate and rotating at 120 RPM. This will be done until two bottoms up are pumped without seeing any more cuttings coming out of the hole. Once the hole is clean, a friction reducer pill will be spotted in the lateral section prior to tripping out of hole from TD. The friction reduction pill consists of 21kg/m3 of walnut medium and 12kg/m3 of graphite and has been proven in the

Duvernay to reduce the friction factor when tripping the BHA out of the hole and running casing.

4.2 2000m Duvernay Well Design Concept

This 2000m well design has been proven in the Duvernay for Shell. It has been seen that it is possible to steer all the way to TD with a conventional bent housing motor so it is not necessary to use a Rotary Steerable System (RSS). The entire production hole can be drilled at a size of 171mm (6 ¾”) and a consistent 29.76kg/m (20 lb/ft) P110EC production casing string can be run to bottom conventionally on elevators without the use of a casing running tool or casing floatation. A conventional cement job is planned with 1600kg/m3 lead cement and 1750kg/m3 tail.

4.2.1 Casing Design/Casing Run (2000m)

The casing design concept for a 2000m well is in table 4.3. The design will be the same for all of the wells on the pad, but the drag charts, drilling hydraulics and cement program will be based on the outer well with a 700m horizontal step out. Based on the drag charts on the casing run even with a 0.45 open hole friction factor the casing will be able to be run to total depth (TD) on elevators without the requirement of a casing running tool.

Table 4.3 Casing Design for 2000m Duvernay Well

Hole Section	Hole Size	Depths	Casing
Surface	311mm	0m–630mMD	244.5mm x 53.57kg/m J55 LTC (0-630m)

Intermediate	222mm	633 – 2800mMD	193.7mm x 44.17kg/m L80E SLIJ2 (0-2800m)
Production	171mm	2800mMD – 5374mMD	139.7mm x 29.76kg/m P110EC VAMTOP HC (0-2800mMD) 139.7mm x 29.76kg/m P110EC VAM SFC (2800mMD-5374mMD)

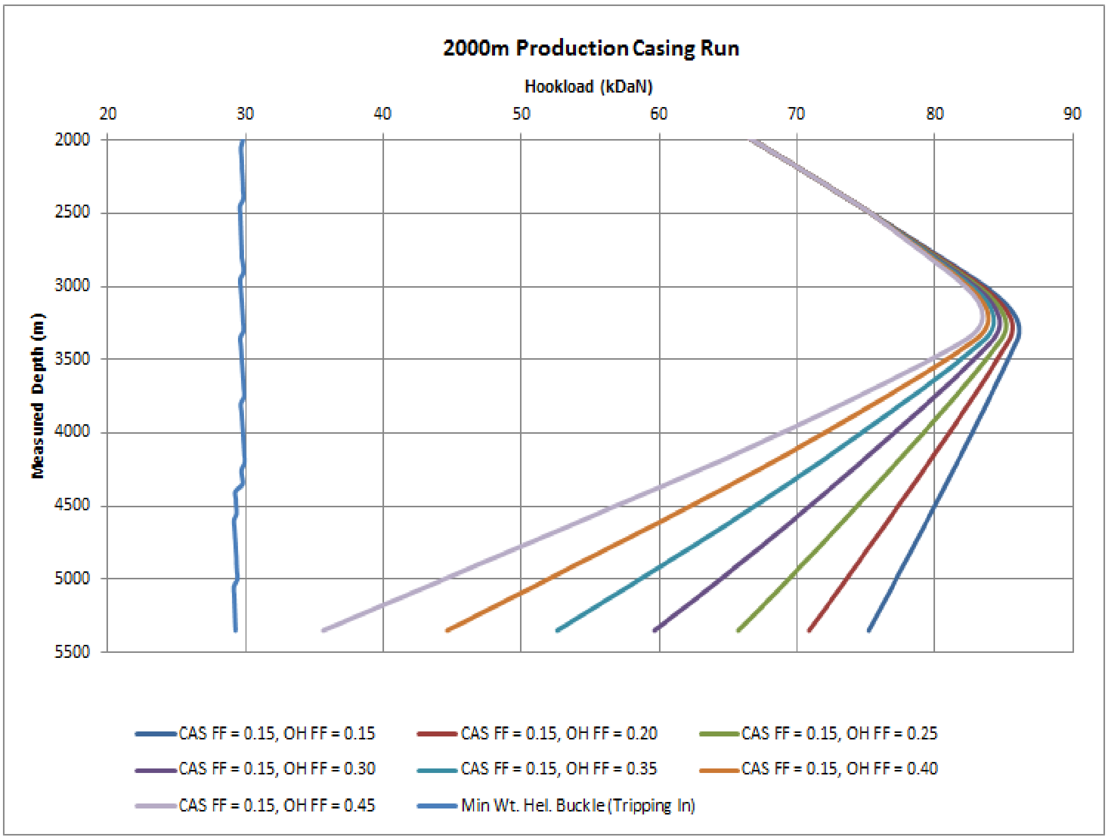

Figure 4.1 Drag Chart for 2000m Duvernay Production Casing Run

4.2.2 BHA Design (2000m)

For the 2000m design a stabilized motor assembly will be run in the horizontal section to drill the 171mm hole because it is cheaper than RSS, and it will still be steerable until total depth. The motor will be a 5/6 lobe 8.3 stage hard rubber motor with a loose fit at surface between the stator rubber and the rotor and it will allow for a maximum differential pressure across the motor of 11,000kpa although the planned differential pressure while drilling will be 5000kpa. While drilling in the lateral the formation temperature is 110 deg C which will cause the stator rubber to expand giving it a proper fit with the rotor. The top stabilizer has an outside diameter of 165mm which is only 6mm under the size of the hole in order to assist with drilling a straight hole in the lateral with minimal time steering. The MWD in the lateral will be the Schlumberger short pulse tool which will be able to communicate with surface even at a total depth of 5374mMD. The drill pipe will be 114.5mm 24.7 kg/m S135 grade with a slim DS40 tool joint with a max OD of 133mm suitable for a 171mm hole. The make-up torque is 28,472 Nm and a tensile rating of the pipe is 209 kDaN which will be sufficient for drilling and tripping out of the hole. The required torque for drilling to TD under normal conditions with a 0.45 friction factor will be 11,500 Nm and the hook load to trip out with a 0.45 friction factor will be 118 kDaN so there is sufficient room for torque spikes and over pulls if drilling problems are encountered. The 114.5mm drill pipe will allow for better hole cleaning and less pressure drop than the 101.6mm drill pipe used on the FC19 long lateral trial. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table XX below summarizes the bottom hole assembly (BHA).

Table 4.4 Drilling BHA for Lateral Section on a 2000m Duvernay Well

Description	Max OD (in)	Length (m)	Cum. Length (m)
6.75" PDC Bit	6.750	0.20	0.20
5" 5/6 8.3 NBR-HR @ 1.5 24x 6.25" BH stab 6.5" Top Sub Stab	6.500	8.70	8.90
Pony NM Slick Collar w/ float non ported	5.000	3.50	12.40
Float Sub (NM non ported)	5.000	1.00	13.40
ShortPulse Med Flo	5.250	10.50	23.90
Pony NM Slick Collar	5.000	3.50	27.40
6.5" NM Nortrak Stab	6.500	1.40	28.80
5" NMDC Slick (2 joints)	5.000	18.82	47.62
Crossover	5.000	0.90	48.52
Drill Pipe 4-1/2 " 16.60# S135 DS40	5.250		To Surface

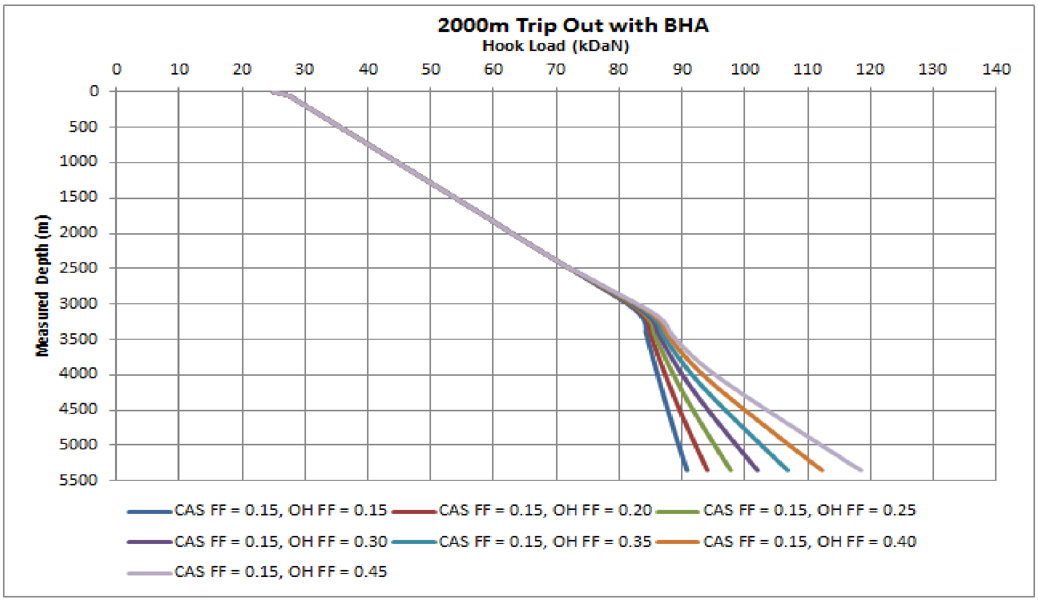

Figure 4.2 Drag Chart for Trip Out of Hole with Drilling BHA on 2000m Lateral

4.2.3 Drilling Fluid Hydraulics (2000m)

The planned pump rate while drilling will be 1.0m3/min and at a total depth of 5370m this will give a total pressure drop through the system of 24,500kpa plus the planned 5,000 kpa differential pressure across the motor will make the total pump pressure while drilling 29,500kpa at TD. If the pressure limitation of the rig is 29,000 kpa then it will be necessary to reduce the flow rate to 0.9 for the last 500m allowing the rig to drill with 27,000kpa pump pressure (22,000 kpa Circulating + 5000 kpa Differential) allowing for a 2000kpa safety margin before blowing the 29,000kpa pop valve on the pumps. The equivalent circulating density (ECD) for the formation at TD with cuttings in the annulus will be 1674 kg/m3 which is well below the 2200kg/m3 equivalent mud weight (EMW) fracture gradient of the Duvernay so losses are not expected.

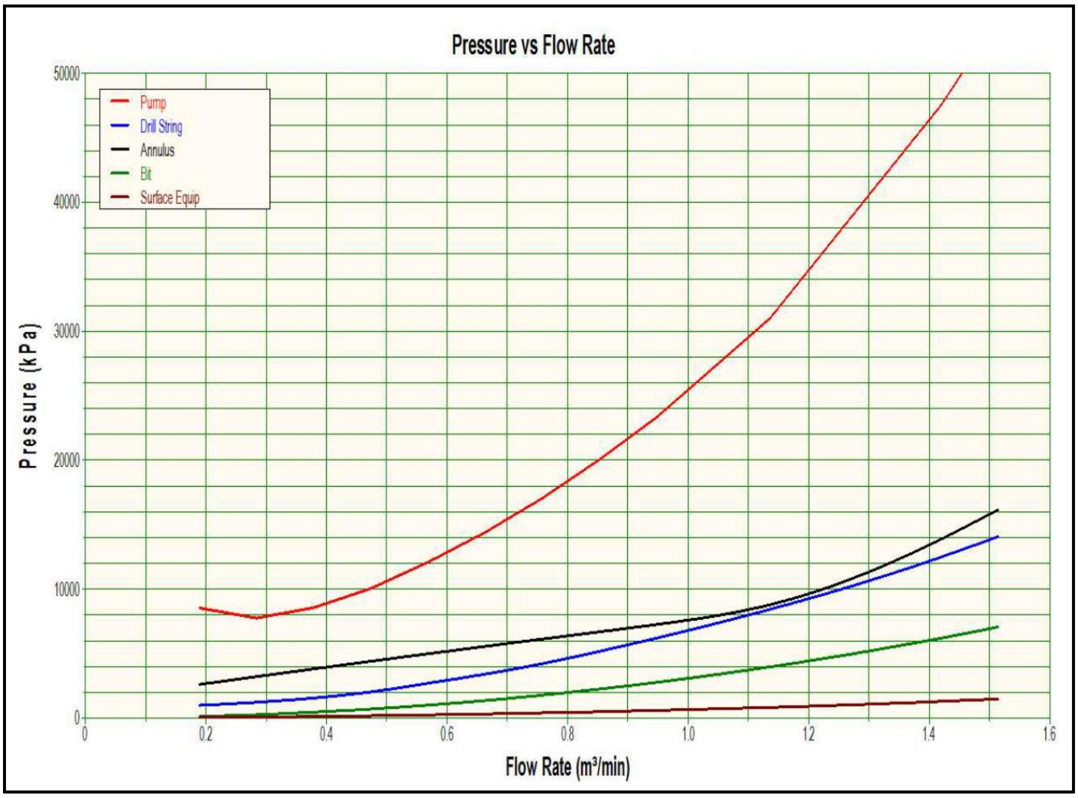

Figure 4.3 Hydraulics Modeling with BHA at TD on a 2000m Well

4.2.4 Cement Job (2000m)

The cement job is planned to consist of pumping a 15m3 tuned spacer with a 1450kg/m3 density to displace the 1400kg/m3 drilling fluid at a rate of 1.0m3/min. There will then be 8.7m3 of 1500kg/m3 lead cement pumped followed by 27.8m3 of 1750kg/m3 of tail slurry. The job is designed for the tail cement to cover the entire horizontal section up to the 2800m, the lead is planned from 2800m up to 1500m, and spacer is left in the hole from 1500m to surface. The Fox Creek 19 pad only had the 1750kg/m3 tail slurry from the toe up to 1500m with no light weight lead cement. By having the lead slurry at a reduced density it reduces the hydrostatic pressure on the Duvernay near the end of the cement job by an EMW of 82 kg/m3 reducing the risk of inducing losses into the Duvernay.

The cement is displaced from the inside of the production casing with inhibited water. The displacement rate will start out at 1.0m3/min, but as the lead cement rises into the vertical portion of the annulus and as more cement is in the wellbore the equivalent circulating density at total depth will increase. The fracture gradient of the Duvernay is at an equivalent mud weight of 2200kg/m3 so the displacement rates are reduced near the end of the job in order to keep the ECD at the toe below 2050kg/m3.

Table 4.5 Cementing Displacement Rates on a 2000m Lateral

Rate m3/min	Volume m3
1.0	**52**
0.7	**5**
0.4	**5.714**

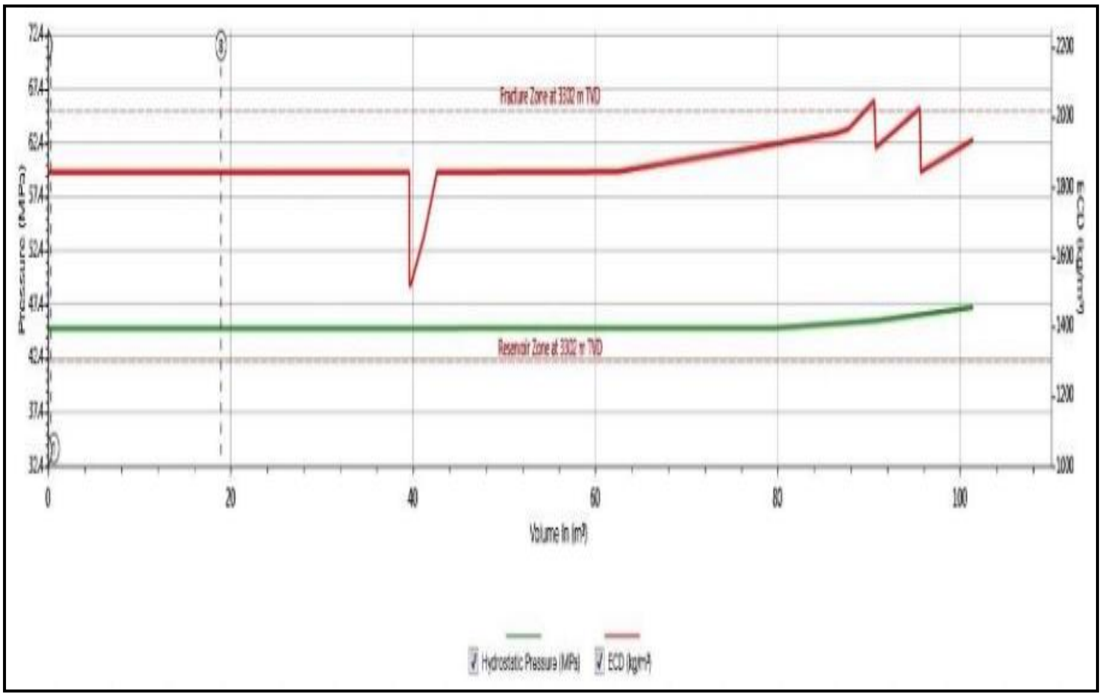

Figure 4.4 Cementing ECDs on a 2000m Lateral

4.2.5 Rig Recommendations (2000m)

Table 4.6 Rig Recommendations for a 2000m Lateral

Hook Load	**170,000 daN** (50,000 daN more than the required hook load to trip the BHA out from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**22,800 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**29,000 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.2.6 Cost Estimate (2000m)

The estimated average cost for drilling a 2000m well on an 8 well development pad with the design in this thesis will be \$3,900,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of \$3,900,000/well for all wells on the pad will be applied for running the development economics. The completion cost will be \$4,600,000/well which assumes that the entire 2000m interval can be completed with 6 clusters/stage. The lease construction and tie in costs are split evenly across every well on the pad and are estimated \$600,000/well. This brings the total cost to drill complete and tie in a 2000m horizontal well on an 8 well pad to \$9,100,000/well.

4.3 2500m Duvernay Well Design Concept

When moving from a 2000m well to a 2500m well it is necessary to use a Rotary Steerable System (RSS) drilling assembly because the increased drag while drilling in the last 500m reduces or eliminates ability to steer with a conventional bent housing motor. The entire production hole can still be drilled at a size of 171mm (6 ¾”) and a consistent 29.76kg/m (20 lb/ft) P110EC production casing string can still be run similar to a 2000m well. It is possible that the production casing will not be able to be run to bottom conventionally due to helical buckling during the last 300m of the run. A Casing Running Tool (CRT) will be available to be used to rotate and circulate the casing to bottom when approaching TD. A conventional cement job is planned similar to what was done for the 2000m well.

4.3.1 Casing Design/Casing Run (2500m)

The casing design concept for a 2500m well is essentially the same as the 2000m well, just with 500m more 139.7mm x 29.76kg/m P110EC VAM SFC production casing in the lateral. Based on the drag chart for the casing run in Figure 4.5 it is likely that casing will be run to TD on elevators, but if the friction factor in the lateral is higher than 0.45 the helical buckling line will be crossed and it is possible that a casing running tool will be needed to circulate and work the casing to bottom. It will not be possible to fully rotate the casing to bottom as the torque required at surface would be 20,800 N-m with a 0.45 friction factor in the open hole which exceeds the 16,200 N-m maximum make up torque of the VAMTOP HC.

Table 4.7 Casing Design for 2500m Duvernay Well

Hole Section	Hole Size	Depths	Casing
Surface	311mm	0m–630mMD	244.5mm x 53.57kg/m J55 LTC (0-630m)
Intermediate	222mm	633 –2800mMD	193.7mm x 44.17kg/m L80E SLIJ2 (0-2800m)
Production	171mm	2800mMD – 5874mMD	139.7mm x 29.76kg/m P110EC VAMTOP HC (0-2800mMD) 139.7mm x 29.76kg/m P110EC VAM SFC (2800mMD-5874mMD)

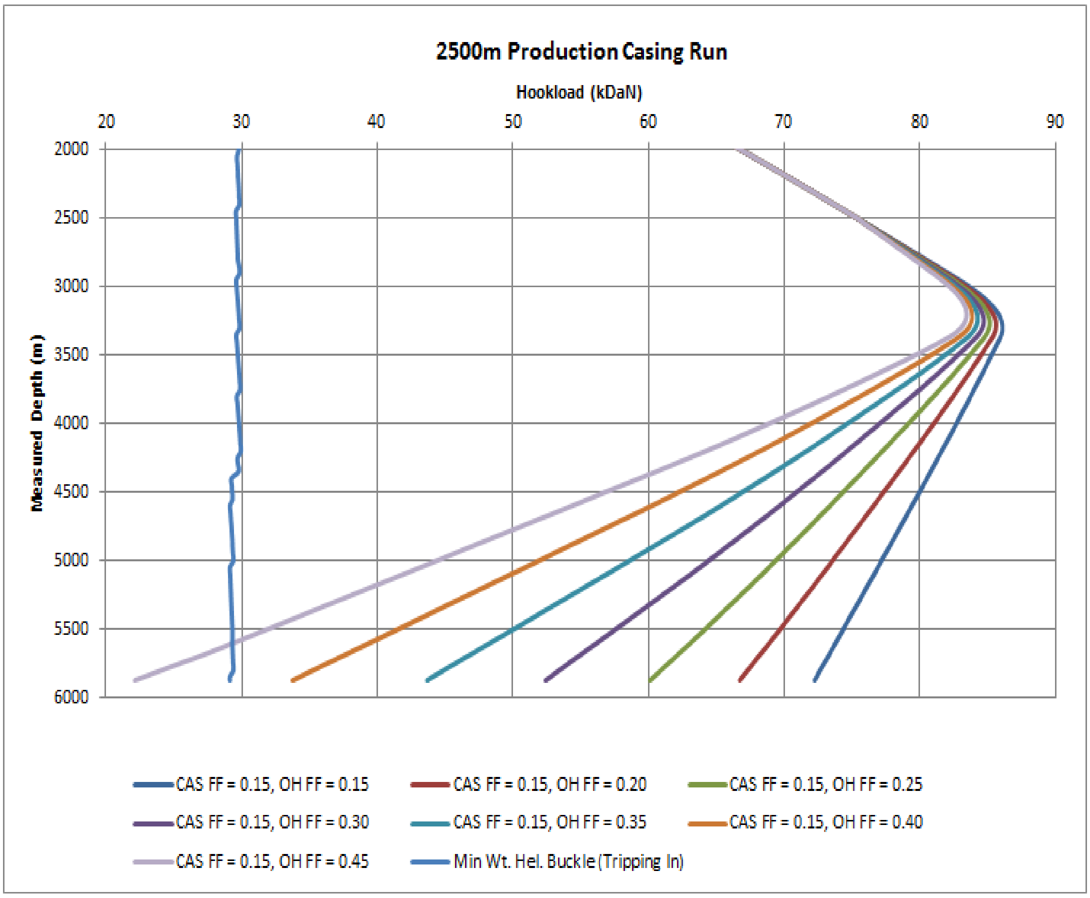

Figure 4.5 Drag Chart for 2500m Duvernay Production Casing Run

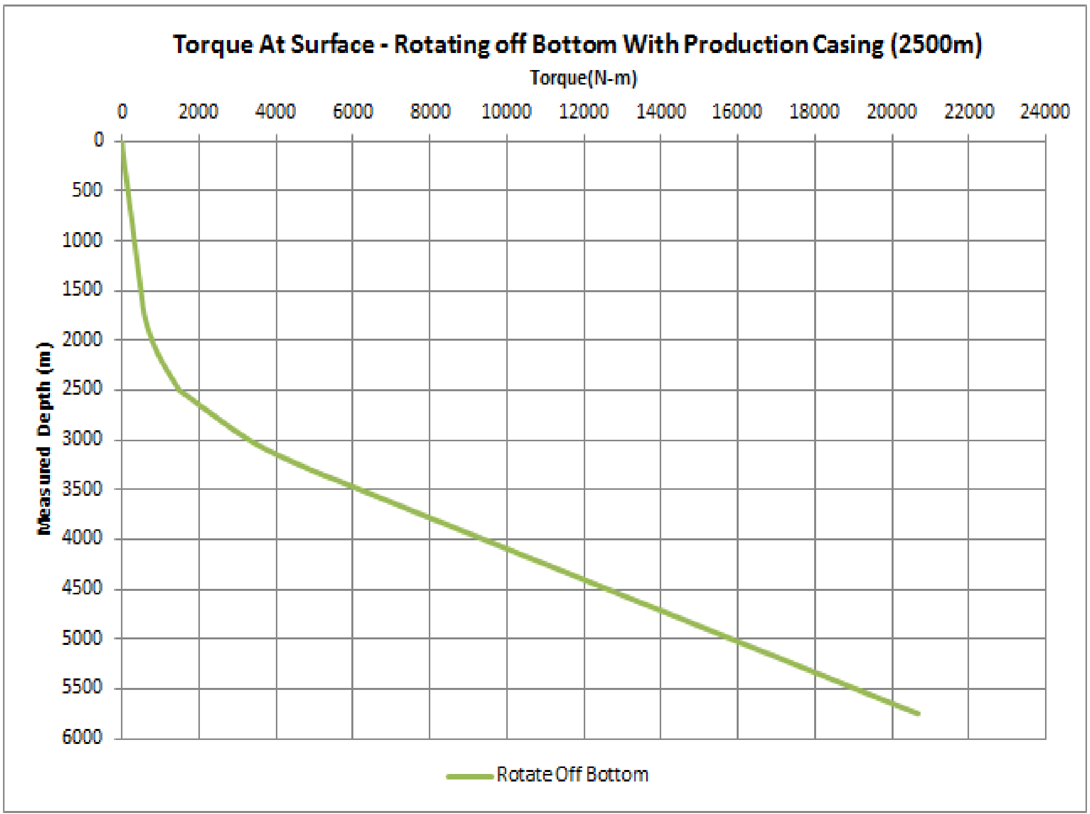

Figure 4.6 Torque at Surface when Rotating Production Casing on a 2000m Lateral

4.3.2 BHA Design (2500m)

For the 2500m design a rotary steerable system will be run in the lateral section. When drilling FC19A it was not possible to steer beyond 2300m into the lateral, and with the 700m step out a rotary steerable system will be required. For this application the 126.5mm PowerDrive ORBIT RSS system from Schlumberger is recommended because it is optimal for holding a straight trajectory in the lateral section of the well and will minimize tortuosity helping with the casing run.

A 127mm a 6/7 lobe 8.0 stage hard rubber motor will be run above the RSS tool in order to turn the RSS and bit at 300 RPM while only rotating the drill string from surface at 120 RMP while pumping at 1.0 m3/min. The motor will be a hard rubber with a loose fit due to the downhole temperatures and there will be a 165mm stabilizer on the motor in order to assist with directional control and to minimize vibration.

The MWD in the lateral will be the Schlumberger short pulse tool which will be able to communicate with surface even at a total depth of 5874mMD. The drill pipe will be 114.5mm 24.7 kg/m S135 grade with a slim DS40 tool joint with a max OD of 133mm suitable for a 171mm hole. The make-up torque is 28,472 Nm and a tensile rating of the pipe is 209 kDaN which will be sufficient for drilling and tripping out of the hole. The required torque for drilling to 5874m with a 0.45 friction factor will be 13,500 Nm and the hook load to trip out with a 0.45 friction factor will be 125 kDaN so there is sufficient room for torque spikes and over pulls if drilling problems are encountered. The 114.5mm drill pipe will allow for better hole cleaning and less pressure drop than the 101.6mm drill pipe used on the FC19 long lateral trial. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table 4.8 below summarizes the bottom hole assembly (BHA).

Table 4.8 Drilling BHA for Lateral Section on a 2500m Duvernay Well

Description	Max OD (in)	Length (m)	Cum. Length (m)
6 3/4" PDC Bit	6.750	0.30	0.30
PowerDrive ORBIT w/non ported float & Filter	6.625	4.06	4.36
5" 6/7 8.0 NBR-HR (SOS) C2 Fixed Straight (6.5" Top Sub Stabilizer with Float)	6.500	9.50	13.86
CLINK4 Upper	5.875	2.87	16.73
ShortPulse High Flow	5.250	8.75	25.48
6.5" String Stab	6.500	1.40	26.88
5" NMDC (2 joints)	5.000	19.00	45.88
Crossover	5.000	0.90	46.78
4-1/2 " 16.60# S135 DS40	5.250	13.30	To Surface

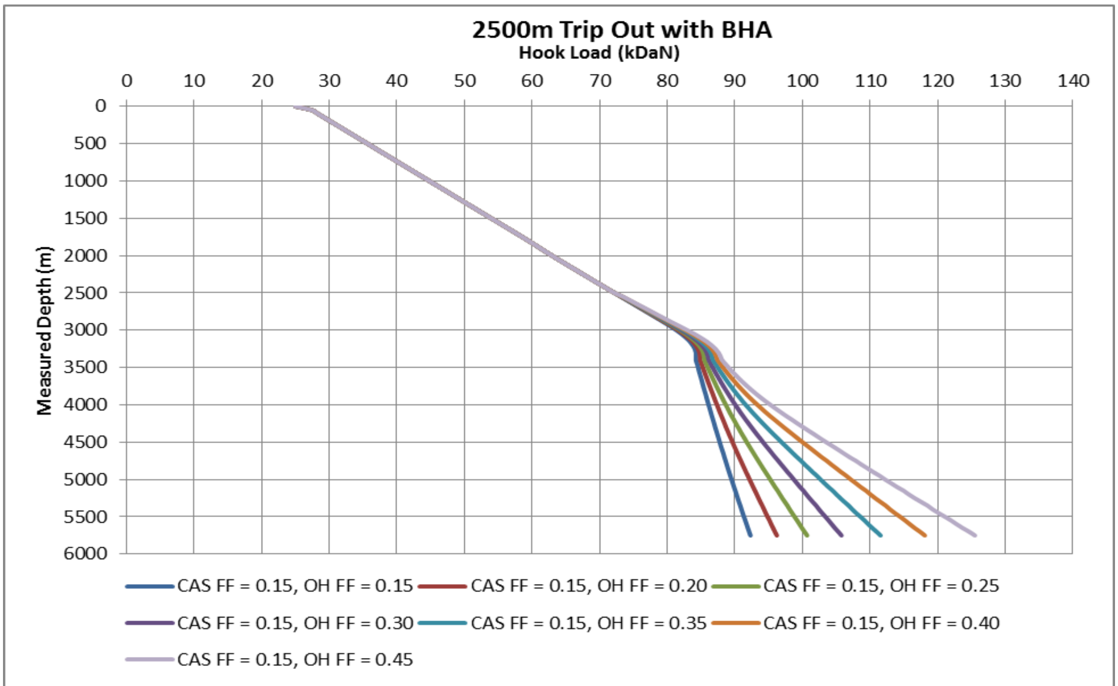

Figure 4.7 Drag Chart for Trip Out of Hole with Drilling BHA on 2500m Lateral

4.3.3 Drilling Fluid Hydraulics (2500m)

The planned pump rate while drilling will be 1.0m3/min and at a total depth of 5870m this will give a total pressure drop through the system of 27,000kpa plus 5,000 kpa differential pressure across the motor and 750kpa across the RSS tool making the total pump pressure while drilling 32,750kpa at TD. The equivalent circulating density (ECD) for the formation at TD with cuttings in the annulus will be 1726 kg/m3 which is significantly below the 2200kg/m3 equivalent mud weight (EMW) fracture gradient of the Duvernay so losses are not expected.

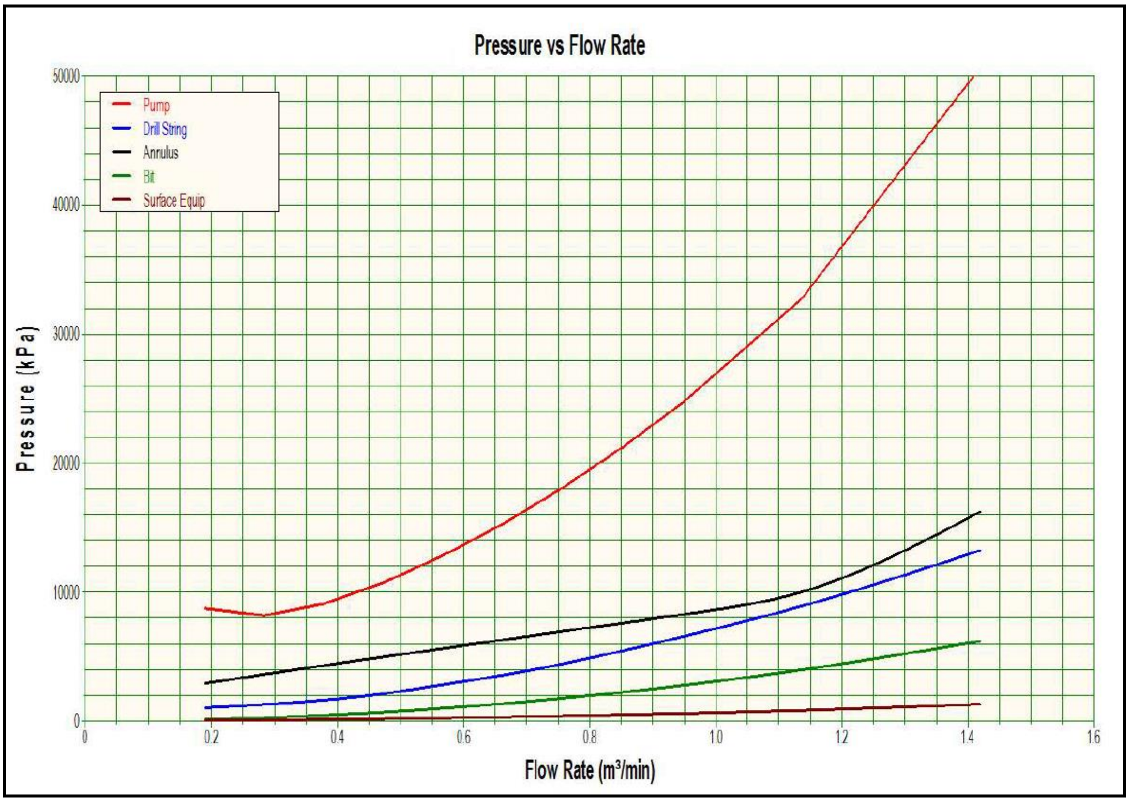

Figure 4.8 Hydraulics Modeling with BHA at TD on a 2500m Well

4.3.4 Cement Job (2500m)

The cement blends and tops of cement are planned the same as on the 2000m lateral with 1750 tail from TD to 2800m and 1500kg/m3 Lead from 2800m to 1500m. It is necessary to raise the maximum cementing ECD to 2150kg/m3 in order to perform the cement job, and the displacement rates are required to be reduced much more near the end of the job. 2500m is at the limit of what can be cemented with this cement blend without breaking down the Duvernay at the toe.

Table 4.9 Cementing Displacement Rates on a 2500m Lateral

Rate m3/min	Volume m3
1.0	**38.0**
0.8	**8.0**
0.5	**10.0**
0.3	**7.605**

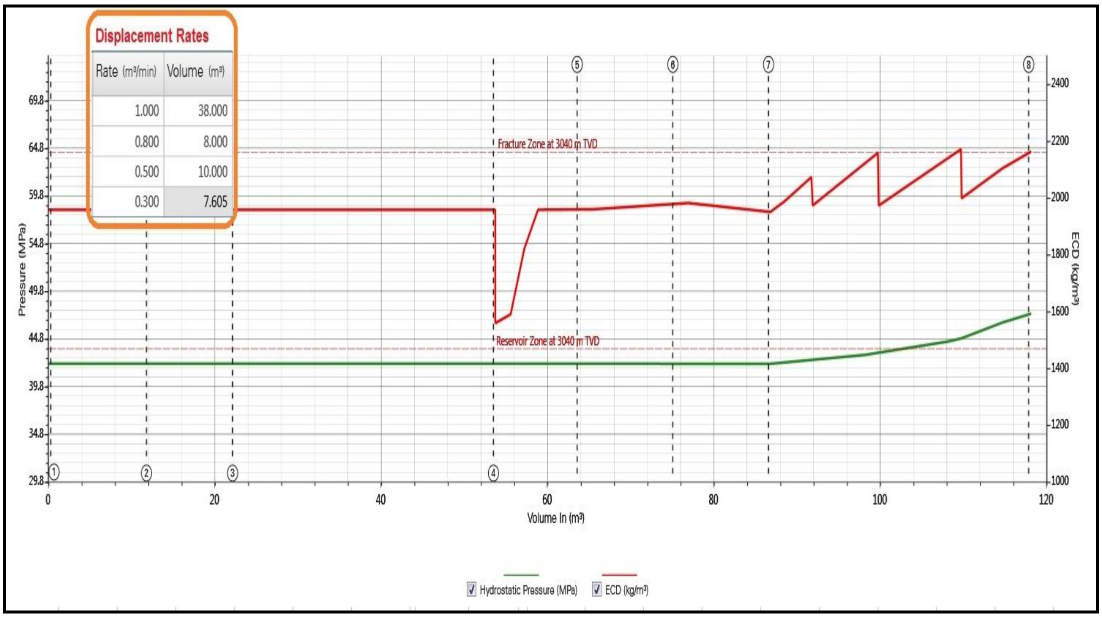

Figure 4.9 Cementing ECDs on a 2500m Lateral

4.3.5 Rig Recommendations (2500m lateral)

Table 4.10 Rig Recommendations for a 2500m Lateral

Hook Load	**175,000 daN** (50,000 daN more than the required hook load to trip the BHA from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**22,800 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**34,750 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.3.6 Cost Estimate (2500m)

The estimated average cost for drilling a 2500m well on an 8 well development pad with the design in this thesis will be $4,100,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of $4,100,000/well for all wells on the pad will be applied for running the development economics. The completion cost will be $5,700,000/well which assuming that 500m closest to the toe is completed with 5 clusters per stage allowing for reduced pump rates due to pressure limitations. The remaining 2000m is completed with 6 clusters per stage. The lease construction and tie in costs are split evenly across every well on the pad and are estimated $600,000/well. This brings the total cost to drill complete and tie in a 2500m horizontal well on an 8 well pad to $10,400,000/well.

4.4 3000m Duvernay Well Design Concept

When moving from a 2500m well to a 3000m well the same Rotary Steerable System (RSS) will be used. The entire production hole can still be drilled at a size of 171mm (6 ¾") and a consistent 29.76kg/m (20 lb/ft) P110EC production casing string can still be run similar to a 2000m or 2500m well. During the casing run it will be necessary to use casing floatation in order to overcome the drag in the lateral and get casing to bottom successfully. During the cement job due to the long wellbore with tight annular clearances it is recommended to perform a foam cement job rather than a traditional cement job. This will allow for higher displacement rates reducing the risk of cement channeling and it reduces the cementing pressures on the formation lowering the risk of inducing losses. Executing an 8 well development pad with 3000m laterals has benefits from a field development stand point because it would allow one pad to fully develop 2 full sections of land.

4.4.1 3000m Casing Design/Casing Run

The casing design for a 3000m well is similar to that of the 2500m and 2000m laterals. The main difference is that it will likely not be possible to run the casing to bottom conventionally. Based on the drag chart in Figure 4.10 it can be seen that without floatation helical buckling will occur and it will not be possible to run the casing to bottom. The torque required to fully rotate the casing to bottom would be 24,600 N-m with a 0.45 friction factor in the open hole which exceeds the 16,200 N-m maximum make up torque of the VAMTOP HC connection.

There is the option of upgrading the production casing to allow for full rotation to bottom, but given the success of casing floatation in the Groundbirch long lateral trial it is more cost effective to use floatation and use the standard casing design. The Groundbirch long laterals also utilized a tapered casing design with larger casing in the vertical section to assist in pushing the casing to bottom. Based on the torque and drag models for running the casing to bottom on a 3000m lateral it is possible to get it to bottom with a 0.55 open hole friction factor utilizing floatation without going to a tapered design.

By positioning the floatation collar at the heel and having the entire 3000m of casing in the lateral full of air while running it will allow the casing to be run on elevators to TD even with a friction factor of 0.55 and a hook load at TD of 41 kDaN. It can be seen that if only 2500m of the casing is run with floatation then with a friction factor of 0.55 then the hook load at TD is only 31kDaN at it is approaching the helical buckling line. The Groundbirch trial found that the modeled friction factors are higher then when modeling a traditional casing run so it will be assumed that a 0.55 friction factor needs to be acceptable in order to get casing to bottom when using floatation. The floatation collar from Import Tool for a 139.7mm casing string has an outside diameter of 154.9mm which will still be acceptable for being placed in a 171mm hole.

Table 4.11 Casing Design for 3000m Duvernay Well

Hole Section	Hole Size	Depths	Casing
Surface	311mm	0m–630mMD	244.5mm x 53.57kg/m J55 LTC (0-630m)
Intermediate	222mm	633 – 2800mMD	193.7mm x 44.17kg/m L80E SLIJ2 (0-2800m)
Production	171mm	2800mMD – 6374mMD	139.7mm x 29.76kg/m P110EC VAMTOP HC (0-2800mMD) 139.7mm x 29.76kg/m P110EC VAM SFC (2800mMD-6374mMD)

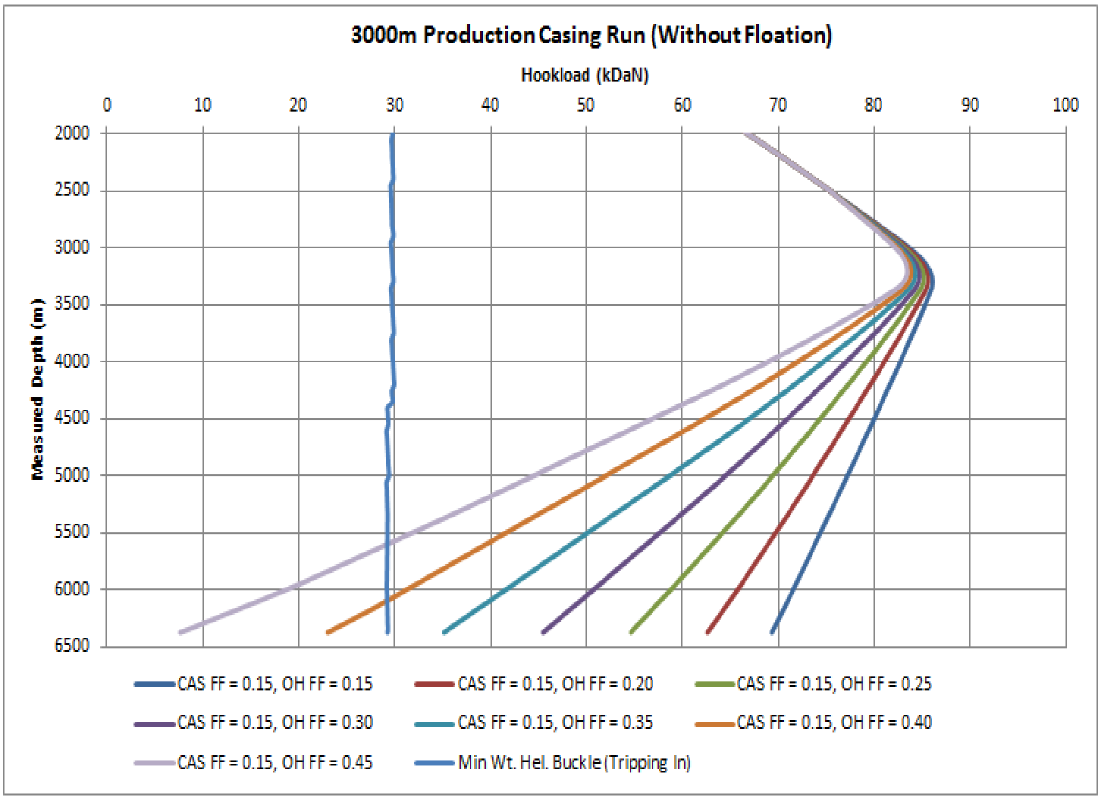

Figure 4.10 Drag Chart for 3000m Production Casing Run Without Floatation

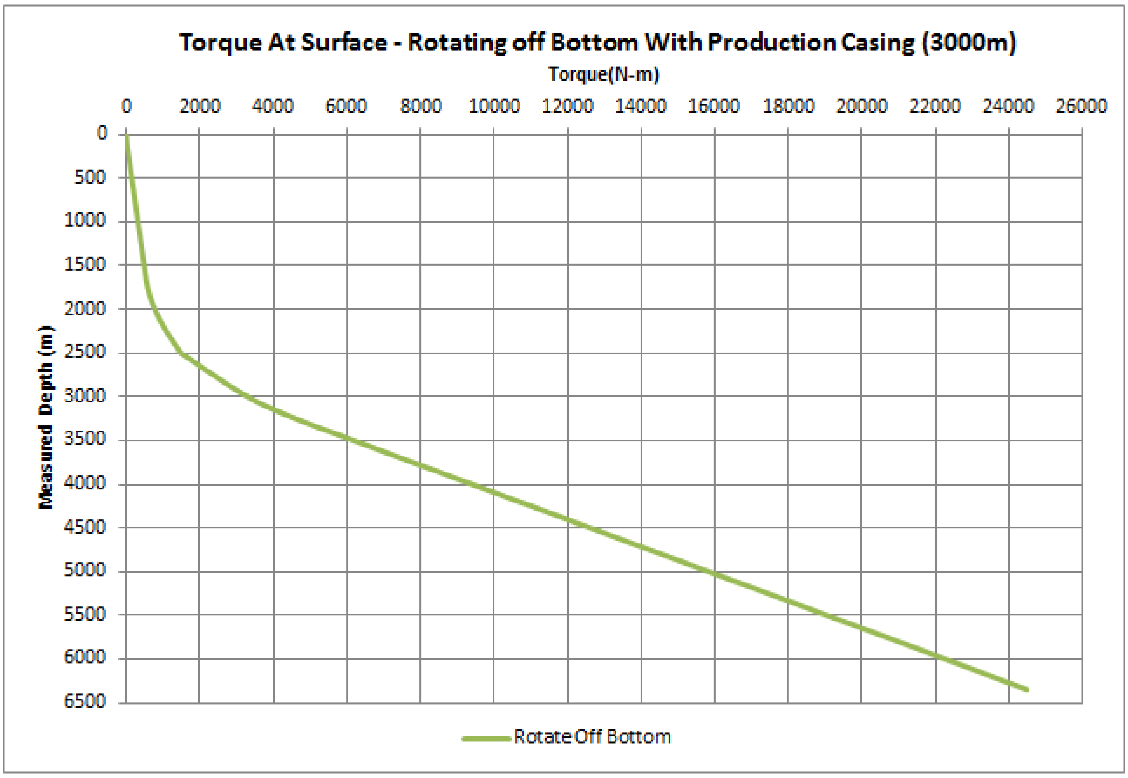

Figure 4.11 Torque at Surface when Rotating Production Casing on a 2500m Lateral

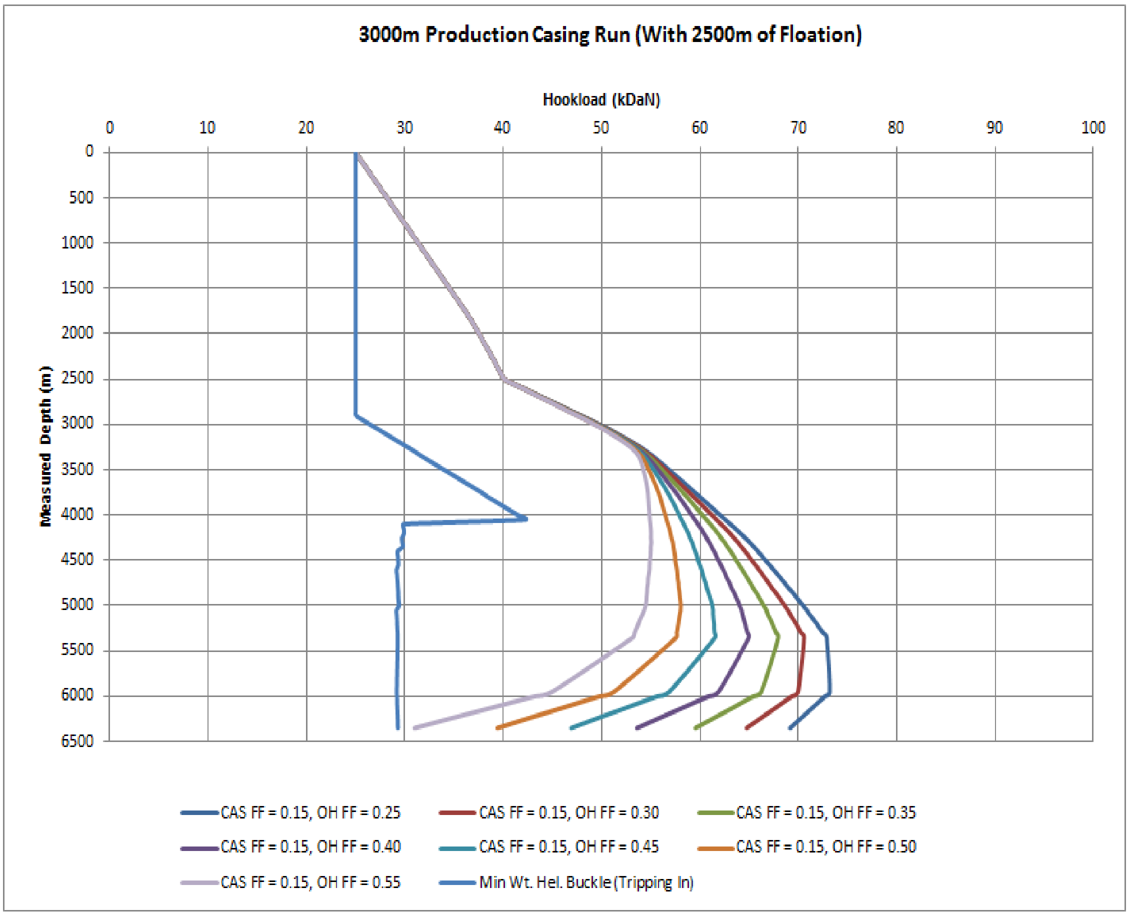

Figure 4.12 Drag Chart for 3000m Production Casing Run (2500m of Floatation)

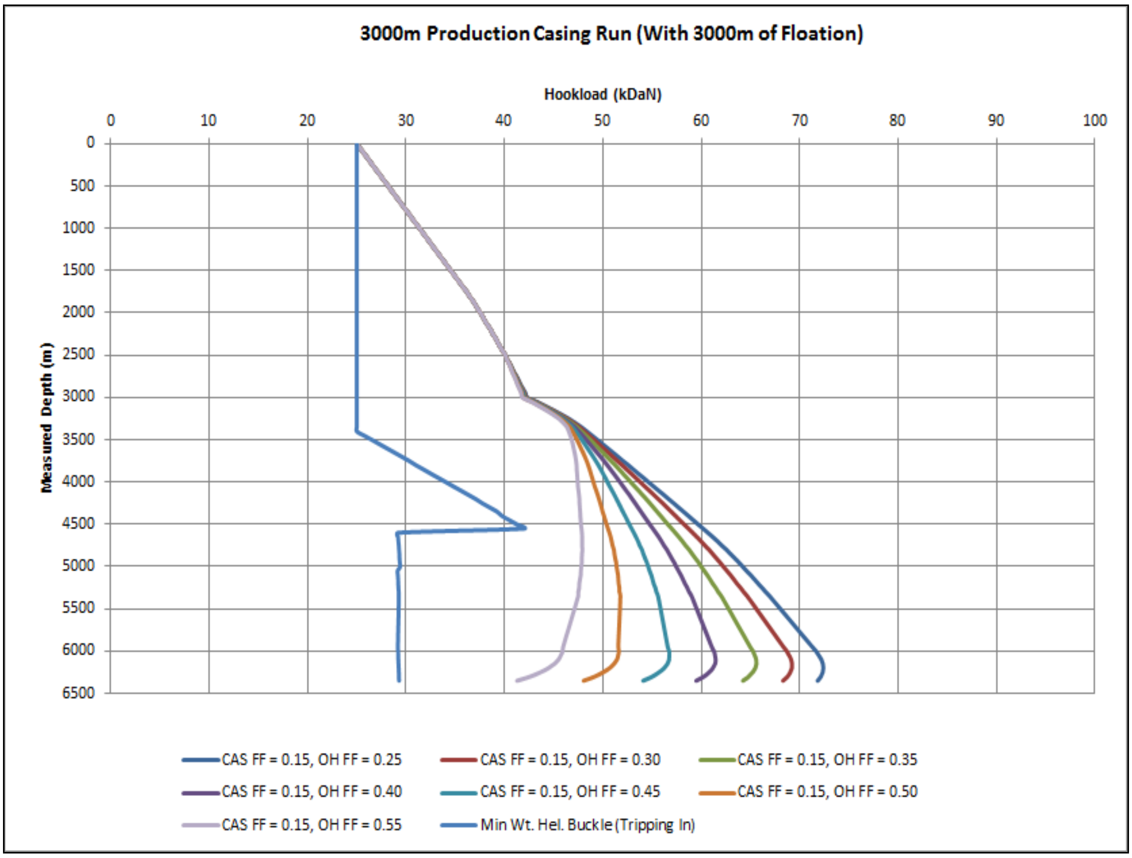

Figure 4.13 Drag Chart for 3000m Production Casing Run (3000m of Floatation)

4.4.2 BHA Design (3000m)

For the 3000m design in a 171mm hole the same a rotary steerable system, BHA and motor will be run as was run on the 2500m lateral. The torque requirements will be higher than on any previous well drilled in the Duvernay. At TD while drilling with 4000 N-m of torque at the bit the torque at surface should be 15,500 N-m and the hook load to trip the BHA out of the hole with a 0.45 open hole friction factor will be 138kDaN. The drill pipe will be 114.5mm 24.7 kg/m S135 grade with a slim DS40 tool joint with a max OD of 133mm suitable for a 171mm hole. The make-up torque is 28,472 Nm and a tensile rating of the pipe is 209 kDaN which will be sufficient for drilling and tripping out of the hole. The 114.5mm drill pipe will allow for better hole cleaning and less pressure drop than the 101.6mm drill pipe used on the FC19 long lateral trial. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table 4.12 summarizes the bottom hole assembly (BHA).

Table 4.12 Drilling BHA for Lateral Section on a 3000m Duvernay Well

Description	Max OD (in)	Length (m)	Cum. Length (m)
6 3/4" PDC Bit	6.750	0.30	0.30
PowerDrive ORBIT w/non ported float & Filter	6.625	4.06	4.36
5" 6/7 8.0 NBR-HR (SOS) C2 Fixed Straight (6.5" Top Sub Stabilizer with Float)	6.500	9.50	13.86
CLINK4 Upper	5.875	2.87	16.73
ShortPulse High Flow	5.250	8.75	25.48
6.5" String Stab	6.500	1.40	26.88
5" NMDC (2 joints)	5.000	19.00	45.88
Crossover	5.000	0.90	46.78
4-1/2 " 16.60# S135 DS40	5.250	13.30	To Surface

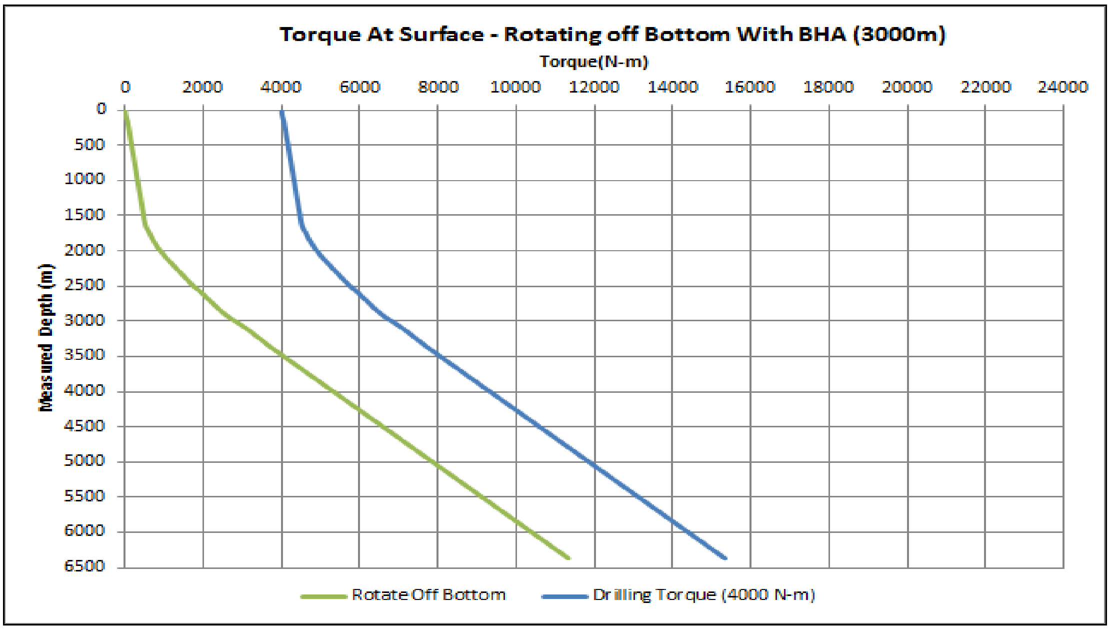

Figure 4.14 Drilling Torque Required for a 3000m Lateral

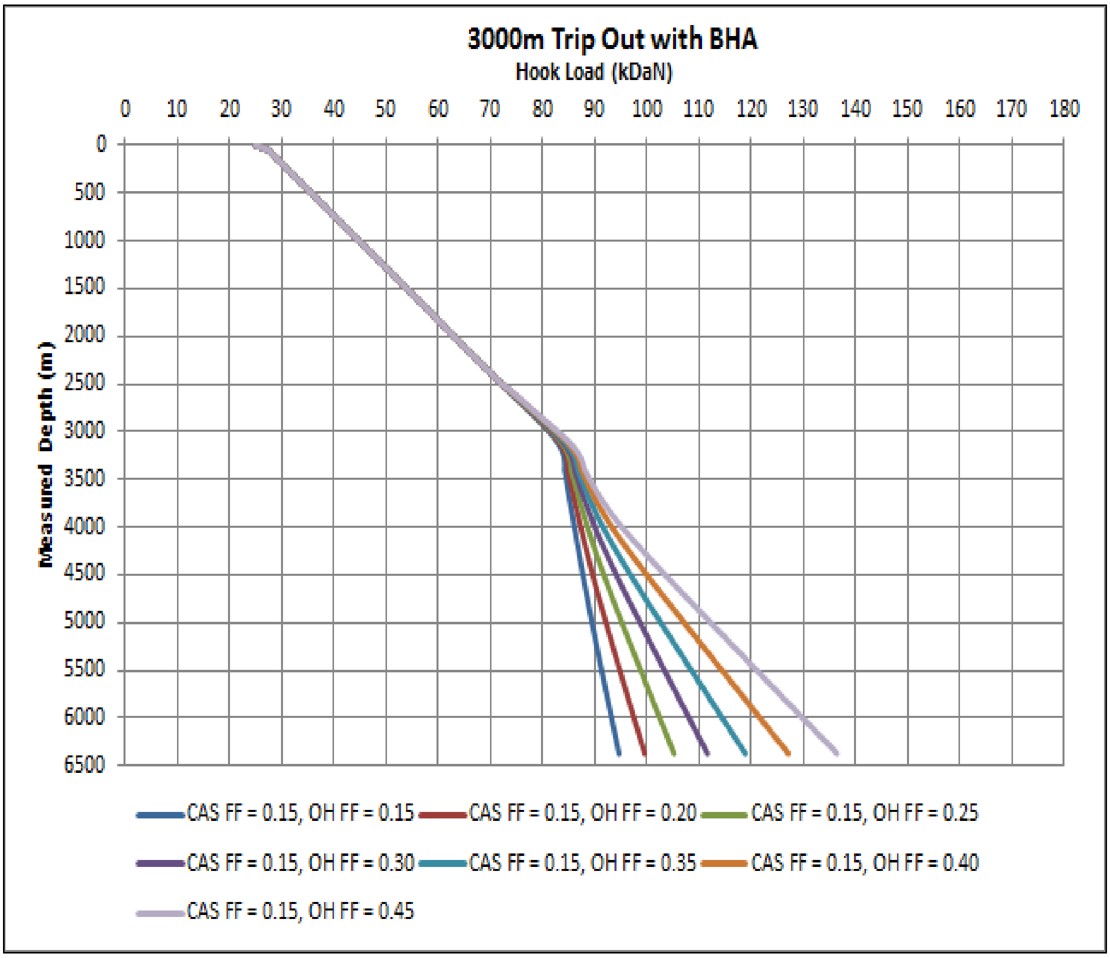

Figure 4.15 Drag Chart for Trip Out of Hole with Drilling BHA on 3000m Lateral

4.4.3 Drilling Fluid and Hydraulics (3000m)

The planned pump rate while drilling will be 1.0m3/min and at a total depth of 6370m this will give a total pressure drop through the system of 29,500kpa plus 5,000 kpa differential pressure across the motor and 750kpa across the RSS tool making the total pump pressure while drilling 35,250kpa at TD. The equivalent circulating density (ECD) for the formation at TD with cuttings in the annulus will be 1788 kg/m3 which is below the 2200kg/m3. equivalent mud weight (EMW) fracture gradient of the Duvernay so losses are not expected.

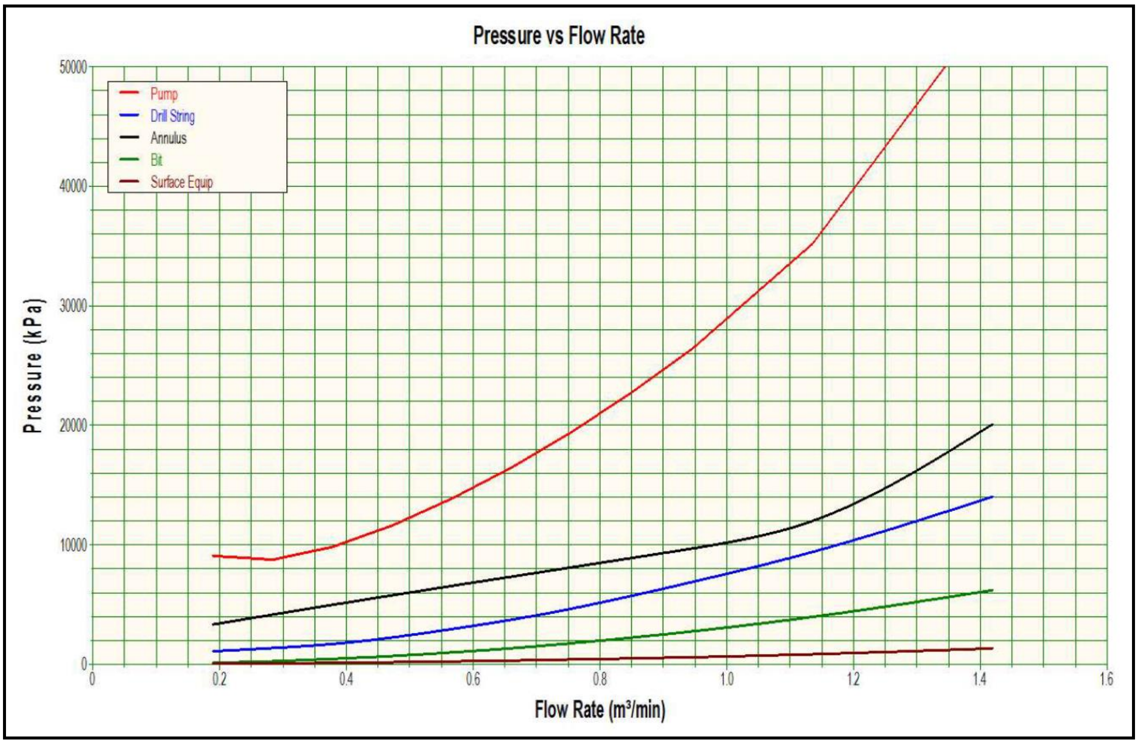

Figure 4.16 Hydraulics Modeling with BHA at TD on a 3000m Well

4.4.4 Cement Job (3000m)

The standard cement blend consisting of 1600kg/m3 lead and 1750 tail is possible for the 3000m well design; however it is necessary to reduce the pump rates even further from where they were on the 2500m design. Low annular velocities during the cement job increase the likelihood of cement channeling in the lateral.

Foam cement is an option which allows for a lighter cement blend allowing for a higher pump rate without causing lost circulation by exceeding the fracture gradient of 2200kg/m3. Foam cement consists of discrete nitrogen bubbles in the cement matrix which do not touch or migrate. The concentration of nitrogen can be increased or decreased in order to get a desired slurry density. The permeability of set foam cement can be much lower compared to other lightweight slurry options. A description of the foam cement job design is in Table 4.14.

Table 4.13 Cementing Displacement Rates on a 3000m Lateral

Foam Cement- 1450 Lead / 1550 Tail		Regular Cement - 1600 Lead / 1750 Tail	
Rate m3/min	Volume m3	Rate m3/min	Volume m3
0.8	35.0	1.0	45.0
0.6	14.0	0.7	10.0
0.7	24.583	0.5	10.0
		0.3	8.583

Table 4.14 3000m Foam Cement Design

Fluid	Density	Volume	Position in Annulus
Spacer	1450kg/m3	20.0 m3	Surface – 2000m
Lead Unfoamed Cement	1750 kg/m3	4.0 m3	2000m – 2500m
Lead Foamed Cement	1450 kg/m3	4.0 m3	2500m – 3000m
Tail Foamed Cement	1550 kg/m3	31.5 m3	3000m – 6374m

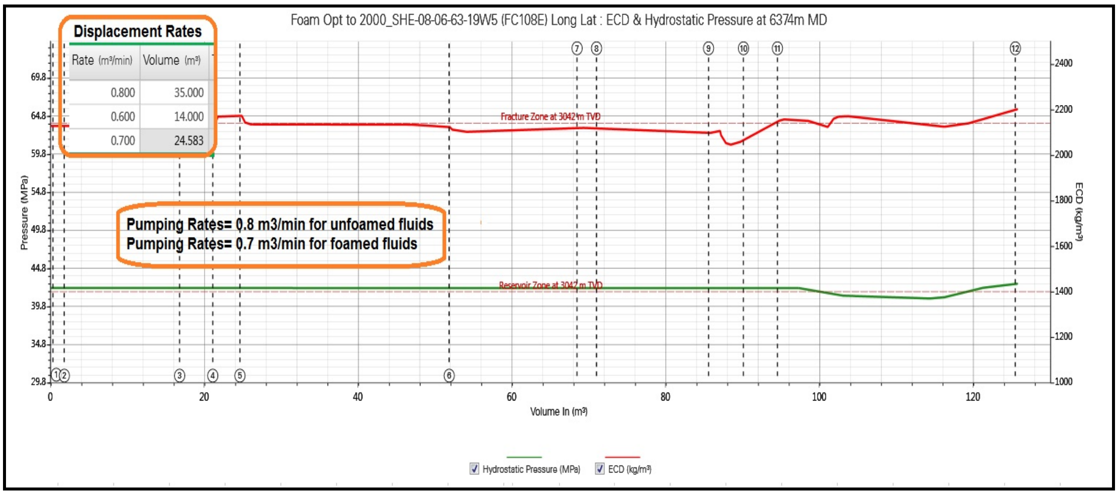

Figure 4.17 Cementing ECDs 3000m Lateral (Foam Cement 1450/1550)

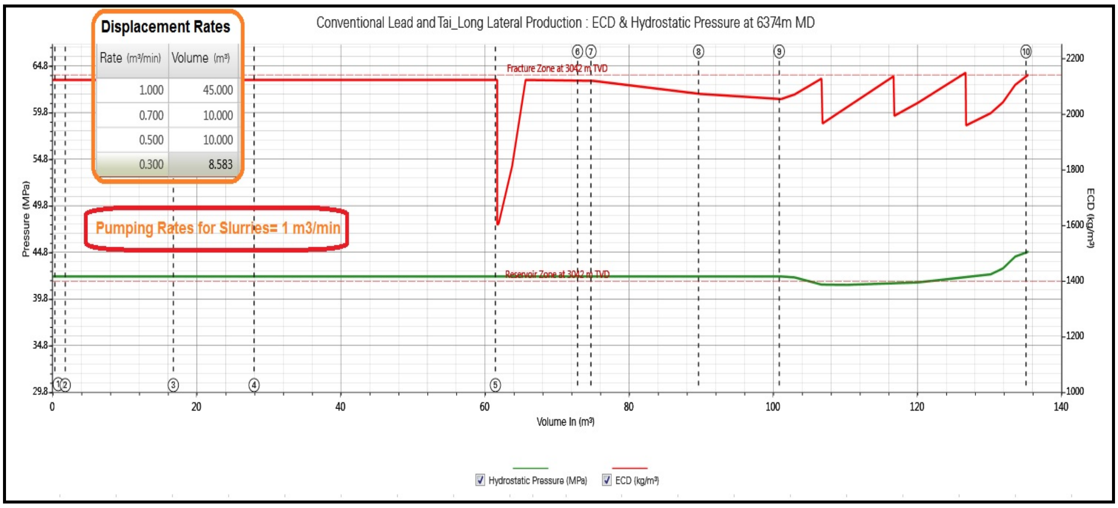

Figure 4.18 Cementing ECDs 3000m Lateral (Regular Cement 1600/1750)

4.4.5 Rig Recommendations (3000m lateral)

Table 4.15 Rig Recommendations for a 3000m Lateral

Hook Load	**185,000 daN** (50,000 daN more than the required hook load to trip the production casing out from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**22,800 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**37,250 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.4.6 Cost Estimate (3000m)

The estimated average cost for drilling a 3000m well on an 8 well development pad with the design in this thesis will be $4,450,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of $4,450,000/well for all wells on the pad will be applied for running the development economics. The completion cost will be $6,780,000/well which assuming that the 1000m closest to the toe is completed with 5 clusters per stage allowing for reduced pump rates due to pressure limitations. The remaining 2000m is completed with 6 clusters per stage. The lease construction and tie in costs are split evenly across every well on the pad and are estimated $600,000/well. This brings the total cost to drill complete and tie in a 3000m horizontal well on an 8 well pad to $11,830,000/well.

4.5 3500m Duvernay Well Design Concept

For a 3500m well the same Rotary Steerable System (RSS) will be used as on the 2500m and 3000m wells. The entire production hole can still be drilled at a size of 171mm (6 ¾”). In order to overcome the drag on the casing run casing floatation will be run similar to the 3000m well, but it is also recommended that a tapered 139.7mm (5.5”) design is used which has 34.23kg/m (23lb/ft) casing from surface to the heel and 29.76kg/m (20 lb/ft) casing in the lateral. Having the heavier casing in the vertical section will help push the casing further out into the lateral allowing it to reach TD. A foam cement job will be required for the 3500m well similar to the one performed on the 3000m well.

4.5.1 3500m Casing Design/Casing Run

The casing design for a 3500m well is going to require a tapered 139.7mm design. The hole and casing sizes will not change, but the casing weight from surface to the heel will be heavier in order to help push the production casing to TD. The casing from surface to the heel will be increased from 29.76kg/m to 34.23kg/m. The casing in the lateral portion of the well will remain 29.76kg/m in order to minimize the drag. It can be seen on the drag chart for the all 29.76kg/m3 design that if a friction factor of 0.55 is seen then it will cross the helical buckling line.

Floatation will be required for this design similar to the 3000m design. The floatation collar will be placed at the heel giving 3500m of air filled casing. Based on the modeling and assuming a friction factor of 0.55 the tapered casing design will get to bottom without crossing the helical buckling line and still having a hook load of 45kDaN at TD compared to 33kDaN with the all 29.76 design. The floatation collar will for a 139.7mm casing string has an outside diameter of 154.9mm which will still be acceptable the 171mm hole.

By running RSS in the lateral to minimize tortuosity, following proper hole cleaning practices at TD and spotting a friction reduction pill in the lateral prior to pulling out with the BHA it is possible that the casing could be run to bottom with a friction factor lower than 0.55. This would open up the possibility of going with an all 29.76kg/m design which would save $60,000.00 in casing costs over the tapered design. For this thesis it will be assumed that a tapered design is required and this will be put into the cost estimate and economics for a 3500m well. The heavier production casing in the vertical has an additional benefit of allowing increased pressures during the completion, however it will be assumed the completion will follow the standard 90kpa fracture design for the completion economics.

Table 4.16 3500m Production Casing Design (34.23kg/m - 29.76kg/m)

Hole Section	**Hole Size**	**Depths**	**Casing**
Surface	311mm	0m–630mMD	244.5mm x 53.57kg/m J55 LTC (0-630m)
Intermediate	222mm	633 – 2800mMD	193.7mm x 44.17kg/m L80E SLIJ2 (0-2800m)
Production	171mm	2800mMD – 6374mMD	139.7mm x 34.23kg/m P110EC VAMTOP HC (0-2800mMD) 139.7mm x 34.23kg/m P110EC VAM SFC (2800mMD-3374mMD) 139.7mm x 29.76kg/m P110EC VAM SFC (3374mMD-6874mMD)

Table 4.17 3500m Production Casing Design (All 29.76kg/m)

Hole Section	**Hole Size**	**Depths**	**Casing**
Surface	311mm	0m–630mMD	244.5mm x 53.57kg/m J55 LTC (0-630m)
Intermediate	222mm	633 – 2800mMD	193.7mm x 44.17kg/m L80E SLIJ2 (0-2800m)
Production	171mm	2800mMD – 6374mMD	139.7mm x 29.76kg/m P110EC VAMTOP HC (0-2800mMD) 139.7mm x 29.76kg/m P110EC VAM SFC (2800mMD-6874mMD)

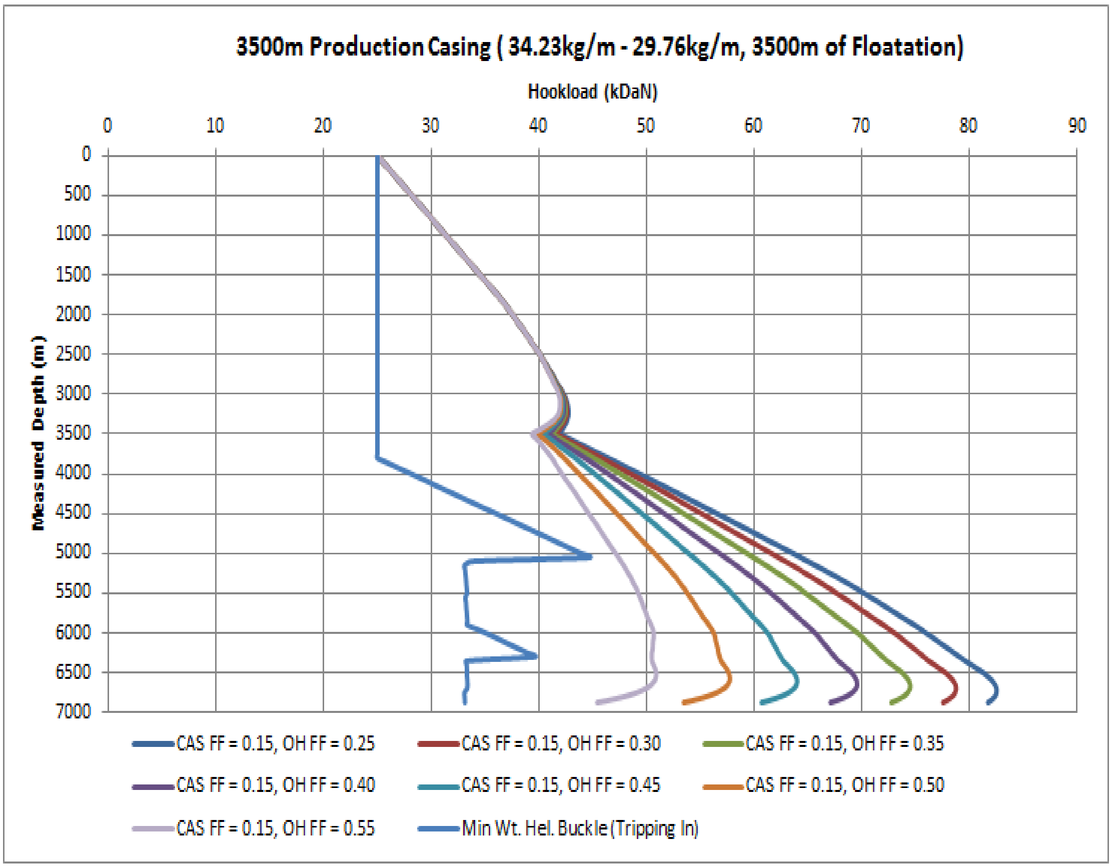

Figure 4.19 Drag for 3500m Production Casing Run (34.23kg/m - 29.76kg/m, 3500m of Floatation)

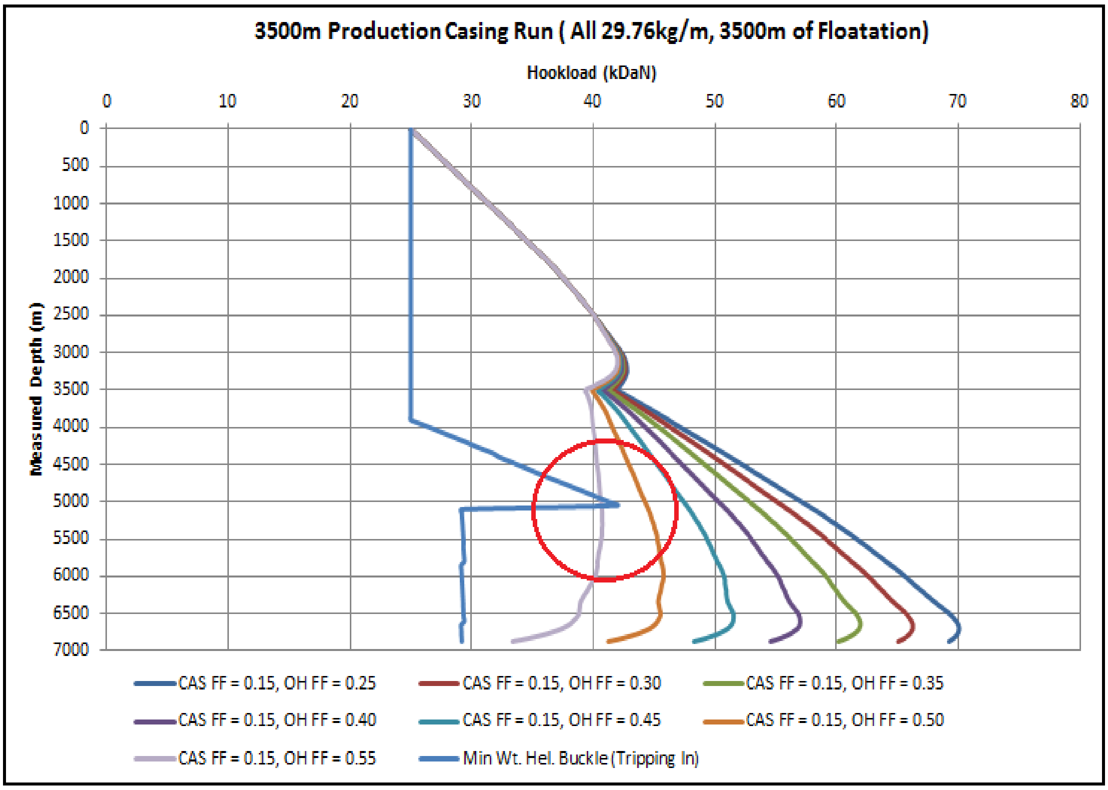

Figure 4.20 Drag for 3500m Production Casing Run (All 29.76kg/m, 3500m of Floatation)

4.5.2 BHA Design (3500m)

For the 3500m design in a 171mm hole the same a rotary steerable system, BHA and motor will be run as was run on the 2500m and 3000m lateral. The torque requirements will be higher than on any previous well drilled in the Duvernay. At TD while drilling with 4000 N-m of torque at the bit the torque at surface should be 16,600 N-m and the hook load to trip the BHA out of the hole with a 0.45 open hole friction factor will be 147kDaN. The drill pipe will be 114.5mm 24.7 kg/m S135 grade with a slim DS40 tool joint with a max OD of 133mm suitable for a 171mm hole. The make-up torque is 28,472 Nm and a tensile rating of the pipe is 209 kDaN which will be sufficient for drilling and tripping out of the hole. The 114.5mm drill pipe will allow for better hole cleaning and less pressure drop than the 101.6mm drill pipe used on the FC19 long lateral trial. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table 4.18 below summarizes the bottom hole assembly (BHA).

Table 4.18 Drilling BHA for Lateral Section on a 3500m Duvernay Well

Description	Max OD (in)	Length (m)	Cum. Length (m)
6 3/4" PDC Bit	6.750	0.30	0.30
PowerDrive ORBIT w/non ported float & Filter	6.625	4.06	4.36
5" 6/7 8.0 NBR-HR (SOS) C2 Fixed Straight (6.5" Top Sub Stabilizer with Float)	6.500	9.50	13.86
CLINK4 Upper	5.875	2.87	16.73
ShortPulse High Flow	5.250	8.75	25.48
6.5" String Stab	6.500	1.40	26.88
5" NMDC (2 joints)	5.000	19.00	45.88
Crossover	5.000	0.90	46.78
4-1/2 " 16.60# S135 DS40	5.250	13.30	To Surface

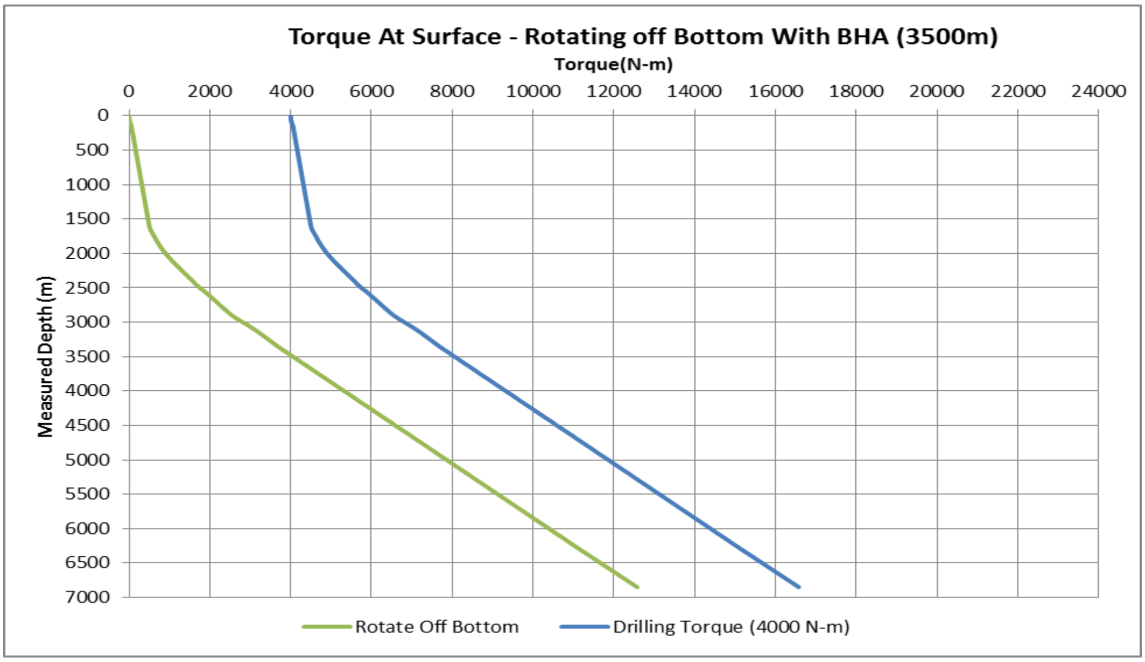

Figure 4.21 Drilling Torque Required for a 3500m Lateral

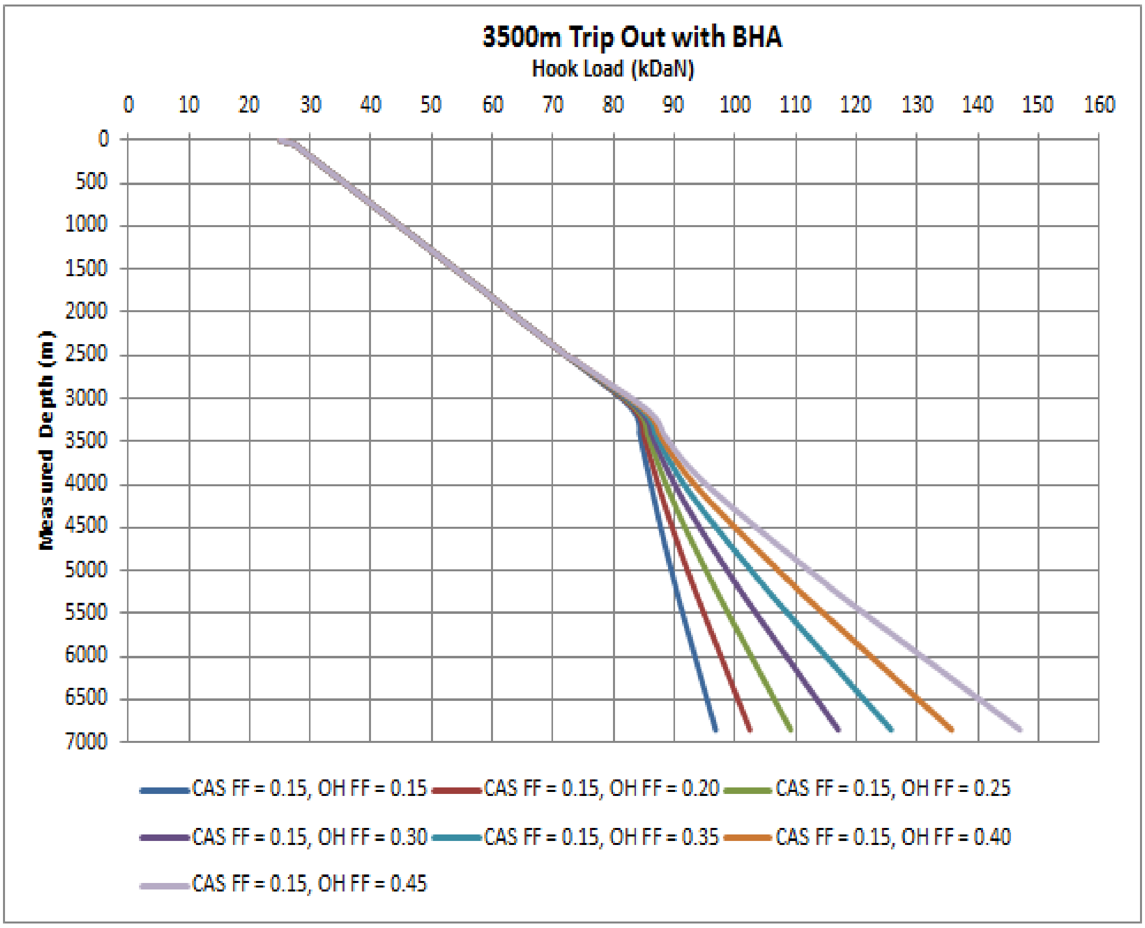

Figure 4.22 Drag Chart for Trip Out of Hole with Drilling BHA on 3500m Lateral

4.5.3 Drilling Fluid Hydraulics (3500m)

The planned pump rate while drilling will be 1.0m3/min and at a total depth of 6870m this will give a total pressure drop through the system of 31.000kpa plus 5,000 kpa differential pressure across the motor and 750kpa across the RSS tool making the total pump pressure while drilling 36,750kpa at TD. The equivalent circulating density (ECD) for the formation at TD with cuttings in the annulus will be 1855 kg/m3 which is below the 2200kg/m3 equivalent mud weight (EMW) fracture gradient of the Duvernay so losses are not expected.

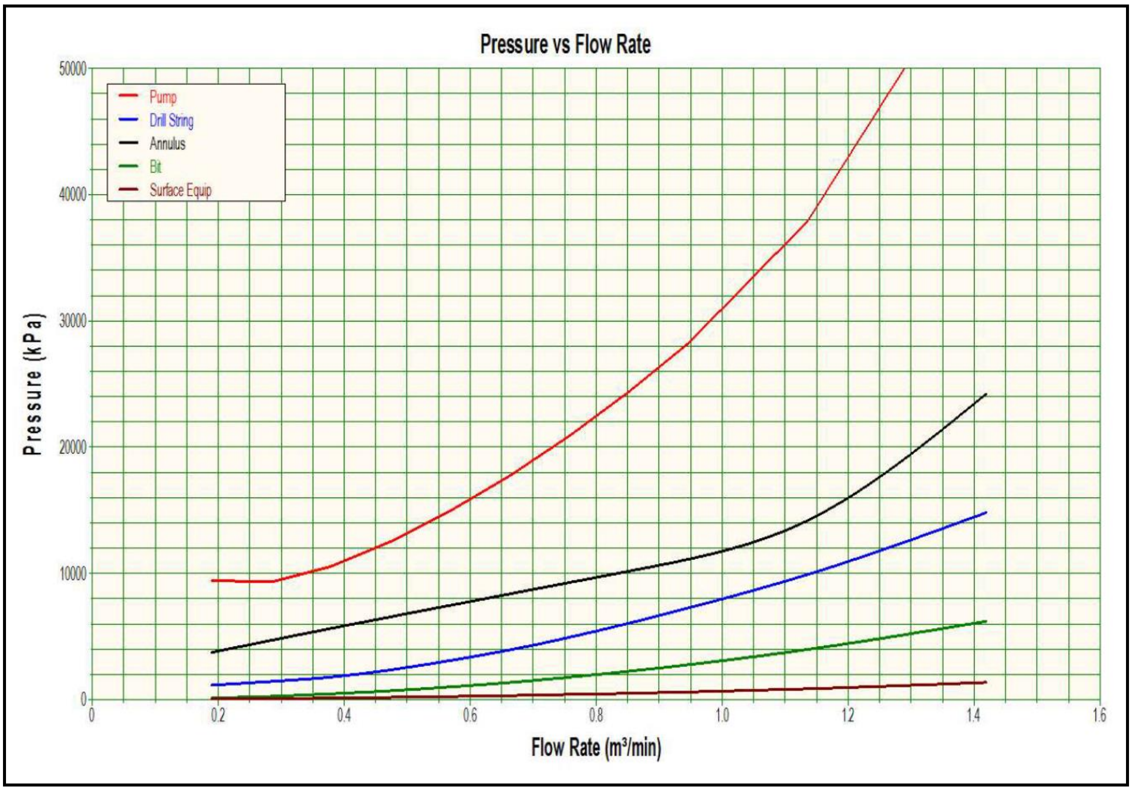

Figure 4.23 Hydraulics Modeling with BHA at TD on a 3500m Well

4.5.4 Cement Job (3500m)

Foam cement will be run similar to what was run on the 3000m cement design. Due to the longer well the densities of the foam cement blends will be reduced to 1400kg/m3 for the lead and 1500kg/m3 for the tail in order to maintain similar displacement rates during the cement job on the 3500m lateral.

Table 4.19 3500m Foam Cement Job Design

Fluid	**Density**	**Volume**	**Position in Annulus**
Spacer	1450kg/m3	20.0 m3	Surface – 2000m
Lead Unfoamed Cement	1750 kg/m3	4.0 m3	2000m – 2500m
Lead Foamed Cement	1400 kg/m3	4.0 m3	2500m – 3000m
Tail Foamed Cement	1500 kg/m3	36.2 m3	3000m – 6374m

Table 4.20 Cementing Displacement Rates on a 3500m Lateral

Displacement Rates Foam Cement- 1400 Lead and 1500 Tail	
Rate m3/min	**Volume m3**
0.7	35.0
0.6	44.223

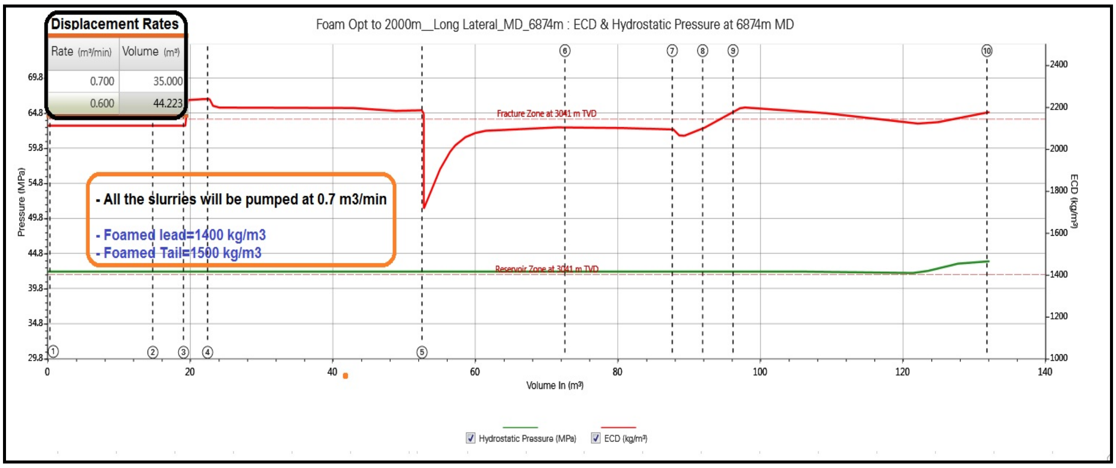

Figure 4.24 Cementing ECDs 3500m Lateral (Foam Cement 1400/1500)

4.5.5 Rig Recommendations (3500m lateral)

Table 4.21 Rig Recommendations for a 3500m Lateral

Hook Load	**197,000 daN** (50,000 daN more than the required hook load to trip out the BHA from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**22,800 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**38,750 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.5.6 Cost Estimate (3500m)

The estimated average cost for drilling a 3500m well on an 8 well development pad with the design in this thesis will be $5,000,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of

$5,000,000/well for all wells on the pad will be applied for running the development economics. The completion cost will be $8,110,000/well which assuming that the 500m closest to the toe is completed with 4 clusters per stage allowing for reduced pump rates due to pressure limitations. The next 1000m will be completed with 5 clusters/ stage, and remaining 2000m closest to the heel are completed with 6 clusters per stage . The lease construction and tie in costs are split evenly across every well on the pad and are estimated $600,000/well. This brings the total cost to drill complete and tie in a 3500m horizontal well on an 8 well pad to $13,710,000/well.

4.6 4000m Duvernay Well Design Concept

Moving to a 4000m well from a 3500m well will require an upsized well design. Even with casing floatation and the tapered design used on the 3500m well it will not be possible to run the casing all the way to TD since there is not enough weight in the vertical portion of the well to overcome the drag in the long lateral section. The well will have an upsized surface and intermediate hole to allow for a 222mm production hole to the heel, and a 200mm hole in the lateral section. A larger Rotary Steerable System (RSS) will be used to drill the 200mm lateral section compared to the BHA used on the previous 171mm holes. The production casing will have 177.8mm x 56.55kg/m (7” x 38 lb/ft) from surface to the heel and 139.7mm x 29.76kg/m (5.5” x 20 lb/ft) from the heel to TD. The same casing floatation system will be run in the 139.7mm casing as was run on the 3000m and 3500m wells. A traditional cement job can be performed similar to the 2000m and 2500m wells because there is more annular clearance with the 200mm hole which reduces the pressures on the formation during the cement job.

4.6.1 4000m Casing Design/Casing Run

In order to execute a 4000m lateral it will not be possible to run an all 139mm casing design. This can be seen in Figure 4.25 that even with the 34.34kg/m by 29.76kg/m tapered design from the 3500m design that unless there is confidence that the casing can be run to bottom with a friction factor of 0.45 or less. For the Groundbirch long lateral trial there was great success with a tapered design consisting of 139.7mm casing in the lateral open hole section and 177.8mm casing from the heel up to surface so this will be the strategy for this application.

All of the hole and casing sizes must be upsized in order to make room for the 177.8mm/139.7mm production casing string. The surface hole will be 406mm in size and a 339.73mm x 81.17kg/m J55 BTC casing string will be run. The intermediate hole will be drilled to the same depth of 2800m which is into the Ireton covering off all sour zones and it will be 311mm in size. The intermediate casing string will be 244.5mm x 69.94kg/m L80 TBlue. The 244.5 mm intermediate casing string has a burst and collapse rating of 47,400kpa and 32,800kpa respectively. The previous 193mm x 44.2kg/m L80 SLIJ-2 had a burst and collapse of 47,500kpa and 33,000kpa respectively so they are almost identical in performance.

The drift of the intermediate casing is 219.9mm which is sufficient for drilling a 216mm hole from 2800m to the heel at 3374m. In the lateral a 200mm hole will be drilled similar to the Groundbirch design. The production casing from surface to the heel at 3374m will be a 177.8mm x 56.55kg/m P110 TBlue which has a burst of

102,400kpa which is slightly higher than the 139.7mm x 29.76kg/m P110EC VAM SFC which has a burst rating of 99,000 kpa. The casing in the horizontal section will be the same the 139.7mm x 29.76kg/m P110EC VAM SFC casing which was run on all of the previous designs. With this design no major changes will need to be made to the completion design, and the same 90,000 kpa completion will be followed as before.

Floatation will be required for this design and the floatation collar will be placed at the heel giving 4000m of air filled casing. Based on the modeling and assuming a friction factor of 0.55 the 177.8mm/139.7mm tapered casing design will get to bottom without crossing the helical buckling line and still having a hook load of 102kDaN at TD.

Table 4.22 4000m Production Casing Design (177.8mm – 139.7mm)

Hole Section	Hole Size	Depths	Casing
Surface	406mm	0m–630mMD	339.73mm x 81.17kg/m J55 BTC (0-630m)
Intermediate	311mm	633 – 2800mMD	244.5mm x 69.94kg/m L80 TBlue (0-2800m)
Production	216mm	0 – 3374mMD	177.8mm x 56.55kg/m P110 TBlue (0-3374mMD)
	200mm	3374mMD – 7374mMD	139.7mm x 29.76kg/m P110EC VAM SFC (3374mMD-7374mMD)

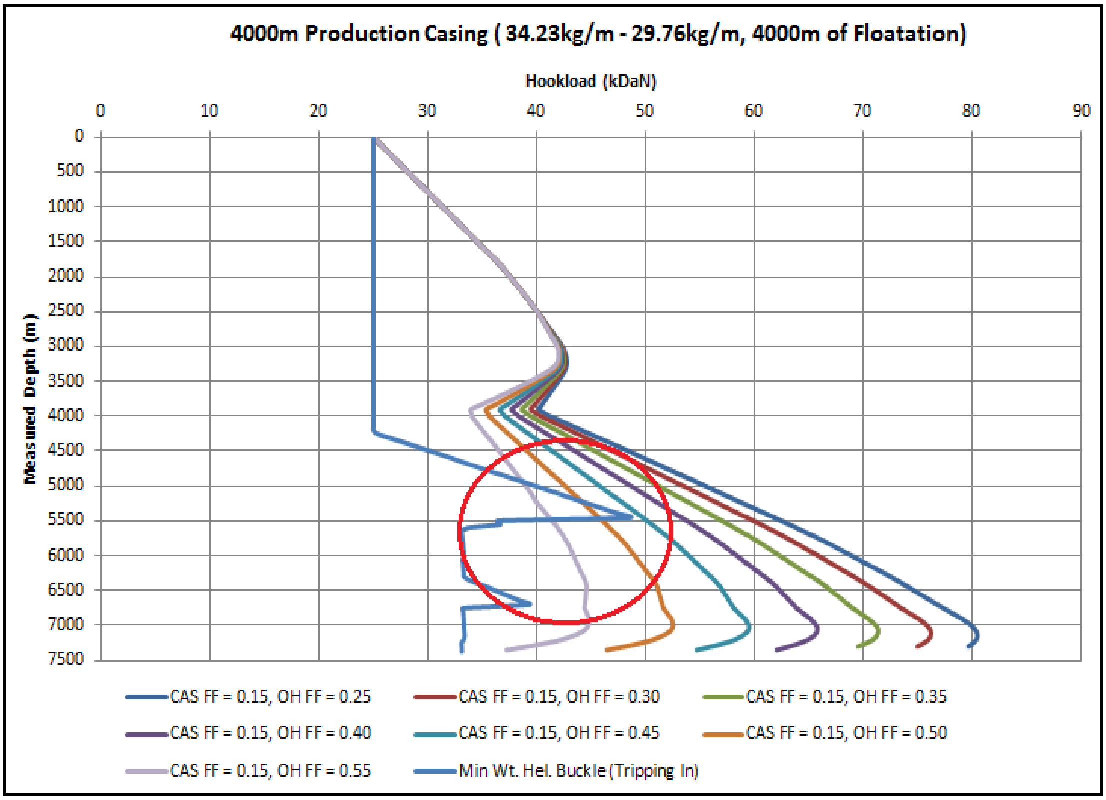

Figure 4.25 Drag for a 4000m Production Casing Run (34.23kg/m - 29.76kg/m, 4000m of Floatation)

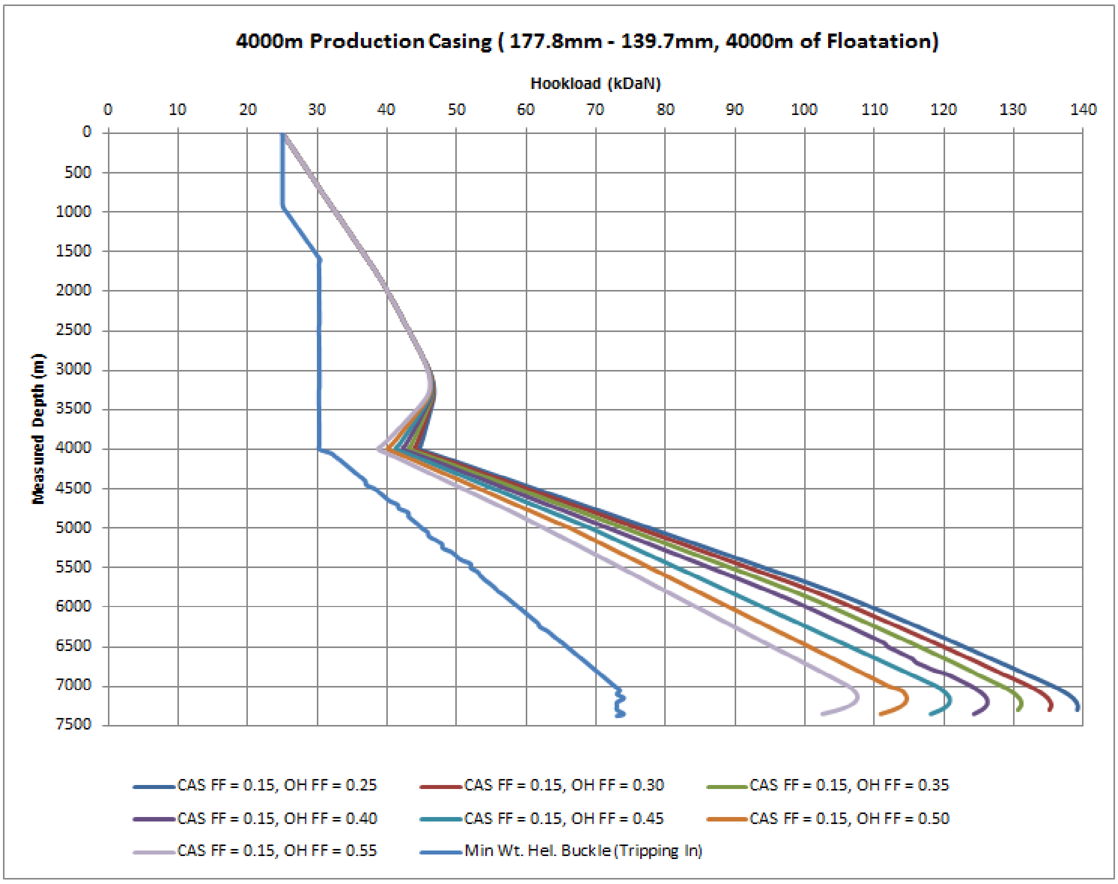

Figure 4.26 Drag for a 4000m Production Casing Run (177.8mm – 139.7mm, 4000m of Floatation)

4.6.2 BHA Design (4000m)

For the 4000m design in a 200mm hole a rotary steerable system, and motor will be run which will give the ability to steer at TD. With the motor above the RSS tool it will make it possible to get 300 RPM at the bit while only rotating at 120 RPM from surface. In the Groundbirch trial when rotating at 200RPM at surface without a motor downhole the torque was much higher, the ROP was less, and there was much more stick slip at the bit then if it had been spinning at 300 RPM. The torque requirement on the 4000m well will be higher than on any previous well drilled in the Duvernay. At TD while drilling with 6000 N-m of torque at the bit the torque at surface should be 28,800 N-m and the hook load to trip the BHA out of the hole with a 0.45 open hole friction factor will be 177kDaN. The drill pipe will be 127mm 29.02 kg/m S-135 grade with a NC50 tool joint with a max OD of 168mm suitable for a 200mm hole. The make-up torque is 41,623 Nm and a tensile rating of the pipe is 250 kDaN which will be sufficient for drilling and tripping out of the hole. The 127mm drill pipe will allow for better hole cleaning and less pressure drop than if 114.3mm drill pipe were to be used in the 200mm hole. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table 4.23 below summarizes the bottom hole assembly (BHA).

Table 4.23 Drilling BHA for Lateral Section on a 4000m Duvernay Well

4000m BHA Description
200mm PDC Bit
175mm Powerdrive RSS
165mm 7/8 3.0 HR Straight Housing Motor with 193.7mm Stabilizer
Short Pulse High Flow
193.7mm stabilizer
165mm NMDC (2 joints)
Crossover
127mm 29.02kg/m S-135 NC50 Drill Pipe to Surface

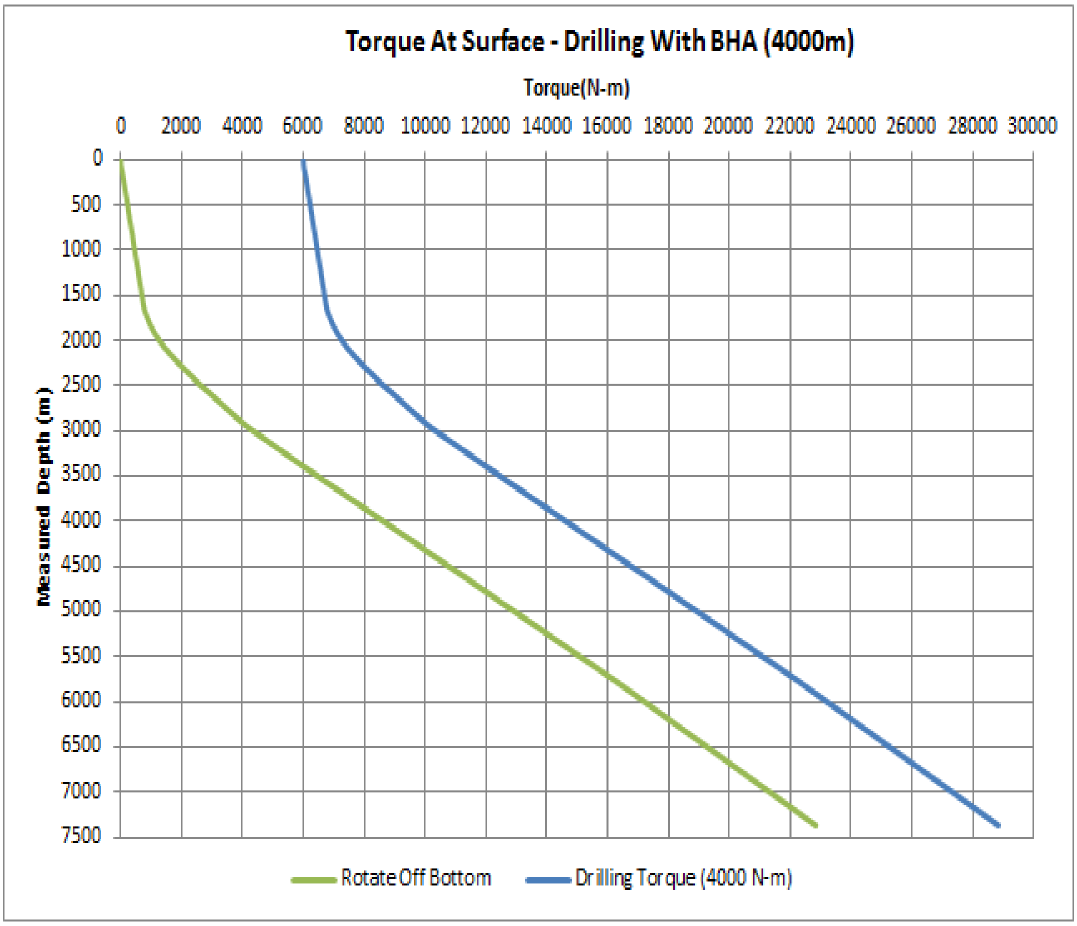

Figure 4.27 Drilling Torque Required for a 4000m Lateral

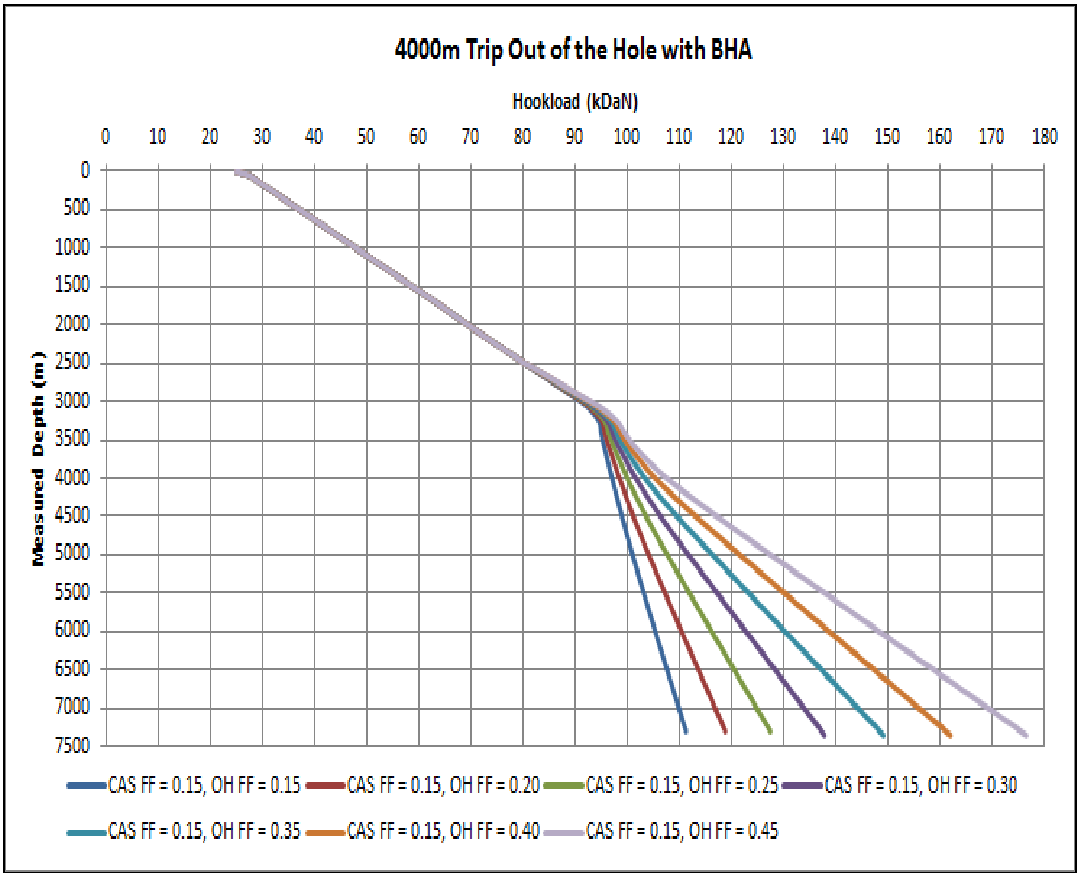

Figure 4.28 Drag Chart for Trip Out of Hole with Drilling BHA on 4000m Lateral

4.6.3 Drilling Fluid Hydraulics (4000m)

The planned pump rate while drilling will be 1.8m3/min and at a total depth of 7370m this will give a total pressure drop through the system of 36,000kpa plus 5,000 kpa differential pressure across the motor and 750kpa across the RSS tool making the total pump pressure while drilling 41,750kpa at TD. The equivalent circulating density (ECD) for the formation at 7374 with cuttings in the annulus will be 1590 kg/m3 which is much lower than what was seen even on the shorter 171mm laterals with 114.3mm drill pipe. This is because the larger 200mm hole creates less pressure drop in the annulus compared to the 171mm hole.

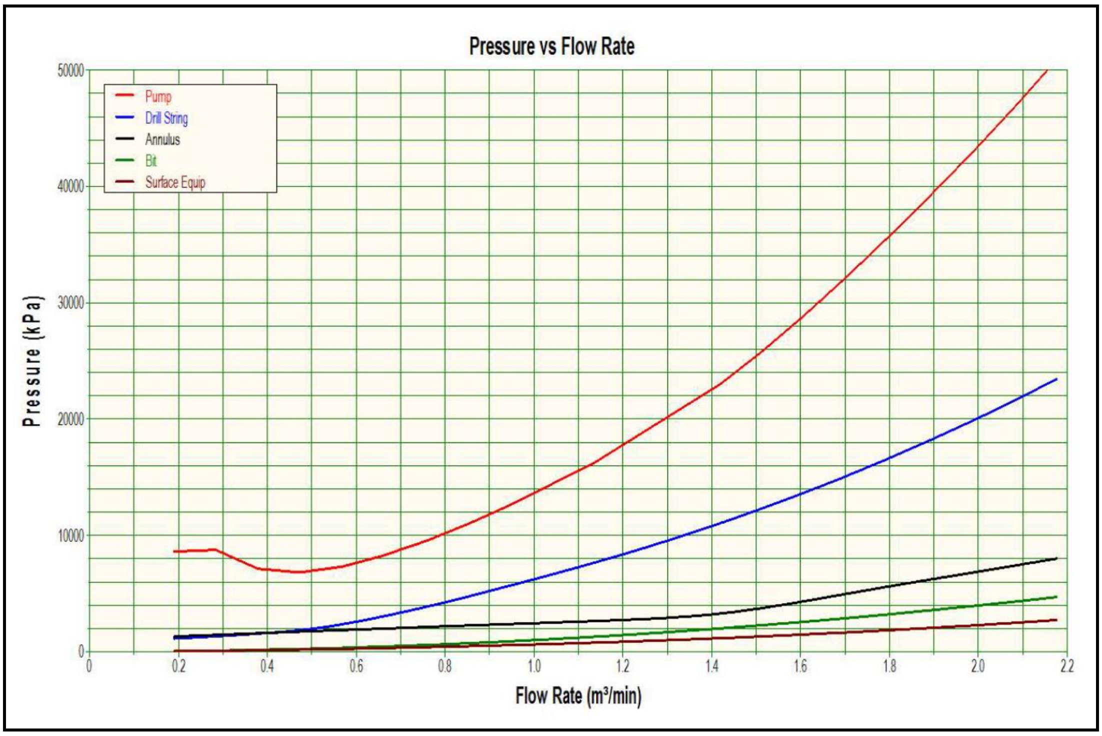

Figure 4.29 Hydraulics Modeling with BHA at TD on a 4000m Well

4.6.4 Cement Job (4000m)

For the cement job on the 4000m tapered design it is possible to run the same conventional cement blend as was run on the 2000m and 2500m laterals due to the larger annular clearance. The cementing ECDs remain low throughout the job, and a constant pumping and displacement rate of 1.0m3/min can be maintained throughout the job simplifying the operation.

Table 4.24 4000m Cement Job Design

Fluid	**Density**	**Volume**	**Position in Annulus**
Spacer	1450kg/m3	20.0 m3	Surface – 1500m
Lead Cement	1600 kg/m3	12.0 m3	1500m – 2500m
Tail Cement	1750 kg/m3	77.9 m3	2500m – 7374m

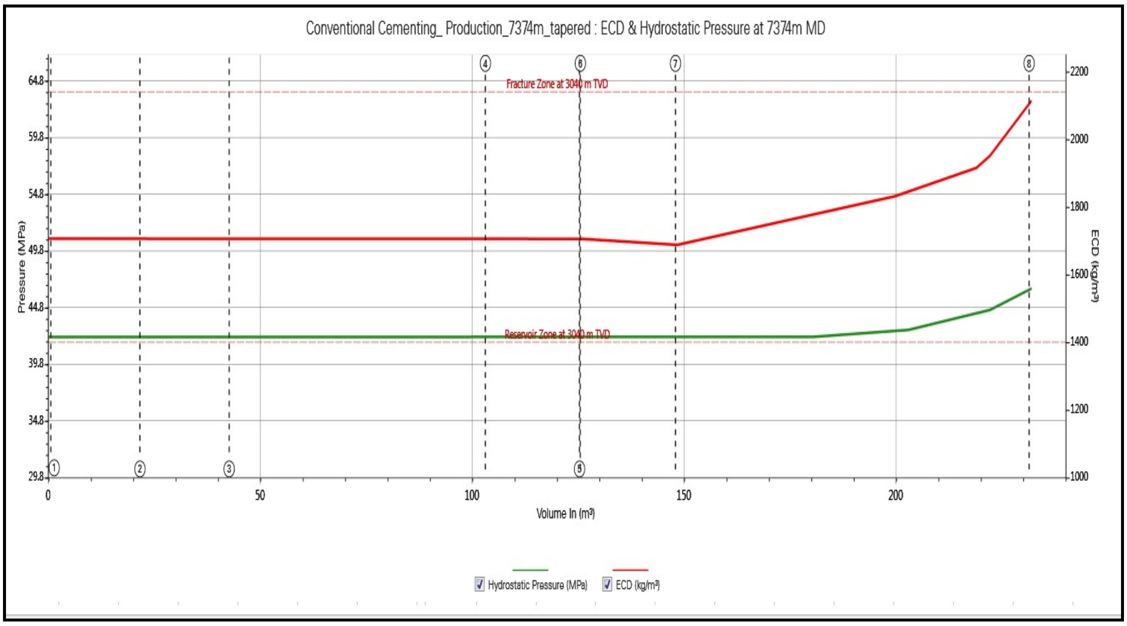

Figure 4.30 Cementing ECDs 4000m Lateral (Regular Cement 1600/1750)

4.6.5 Rig Recommendations (4000m lateral)

Table 4.25 Rig Recommendations for a 4000m Lateral

Hook Load	**227,000 daN** (50,000 daN more than the required hook load to trip out the BHA from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**33,300 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**43,750 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.6.6 Cost Estimate (4000m)

The estimated average cost for drilling a 4000m well on an 8 well development pad with the design in this thesis will be $7,000,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of $7,000,000/well for all wells on the pad will be applied for running the development economics. There is a substantial increase in cost for this design due to the increased casing cost and drilling time because of the upsized hole and casing sizes to accommodate the 177.8mm/139.7mm tapered casing design. The rig requirements are also greater due to the added rig requirements for hook load, torque and pump pressure which further increases the cost of this design relative to the shorter laterals. The completion cost will be $9,400,000/well which assuming that the 1000m closest to the toe is completed with 4 clusters per stage allowing for reduced pump rates due to pressure limitations. The next 1000m will be completed with 5 clusters/ stage, and remaining 2000m closest to the heel are completed with 6 clusters per stage . The lease construction and tie in costs are split evenly across every well on the pad and are estimated $600,000/well. This brings the total cost to drill complete and tie in a 4000m horizontal well on an 8 well pad to $17,000,000/well.

4.7 4500m Duvernay Well Design

Moving to a 4500m well from a 4000m well does not require any major design changes. The same production casing design will be used as on the 4000m well with 177.8mm x 56.55kg/m (7” x 38 lb/ft) from surface to the heel and 139.7mm x 29.76kg/m (5.5” x 20 lb/ft) from the heel to TD. Casing floatation will be utilized in the lateral to reduce drag and get casing to bottom. A traditional cement job can be performed similar to the 2000m, 2500m, and 4000m wells. Executing an 8 well development pad with 4500m laterals has benefits from a field development stand point because it would allow one pad to fully develop 3 full sections of land.

4.7.1 4500m Casing Design/Casing Run

In order to execute a 4500m lateral it will be necessary to run the same 177.8mm/139.7mm casing design as was run for the 4000m lateral. Floatation will be required for this design and the floatation collar will be placed at the heel which is 4500m from the toe. There is a reduction of hook load seen up until 4500m because at this point the casing is 1126m into the lateral and is still completely empty. At 4500m the floatation collar is installed and then there is a crossover to the 177.8mm casing which begins to help push the casing to bottom. Based on the modeling and assuming a friction factor of 0.55 the 177.8mm/139.7mm tapered casing design will get to bottom without crossing the helical buckling line and still having a hook load of 95kDaN at TD.

Table 4.26 4500m Production Casing Design (177.8mm – 139.7mm)

Hole Section	Hole Size	Depths	Casing
Surface	406mm	0m–630mMD	339.73mm x 81.17kg/m J55 BTC (0-630m)
Intermediate	311mm	633 – 2800mMD	244.5mm x 69.94kg/m L80 TBlue (0-2800m)
Production	216mm	0 – 3374mMD	177.8mm x 56.55kg/m P110 TBlue (0-3374mMD)
	200mm	3374mMD – 7874mMD	139.7mm x 29.76kg/m P110EC VAM SFC (3374mMD-7874mMD)

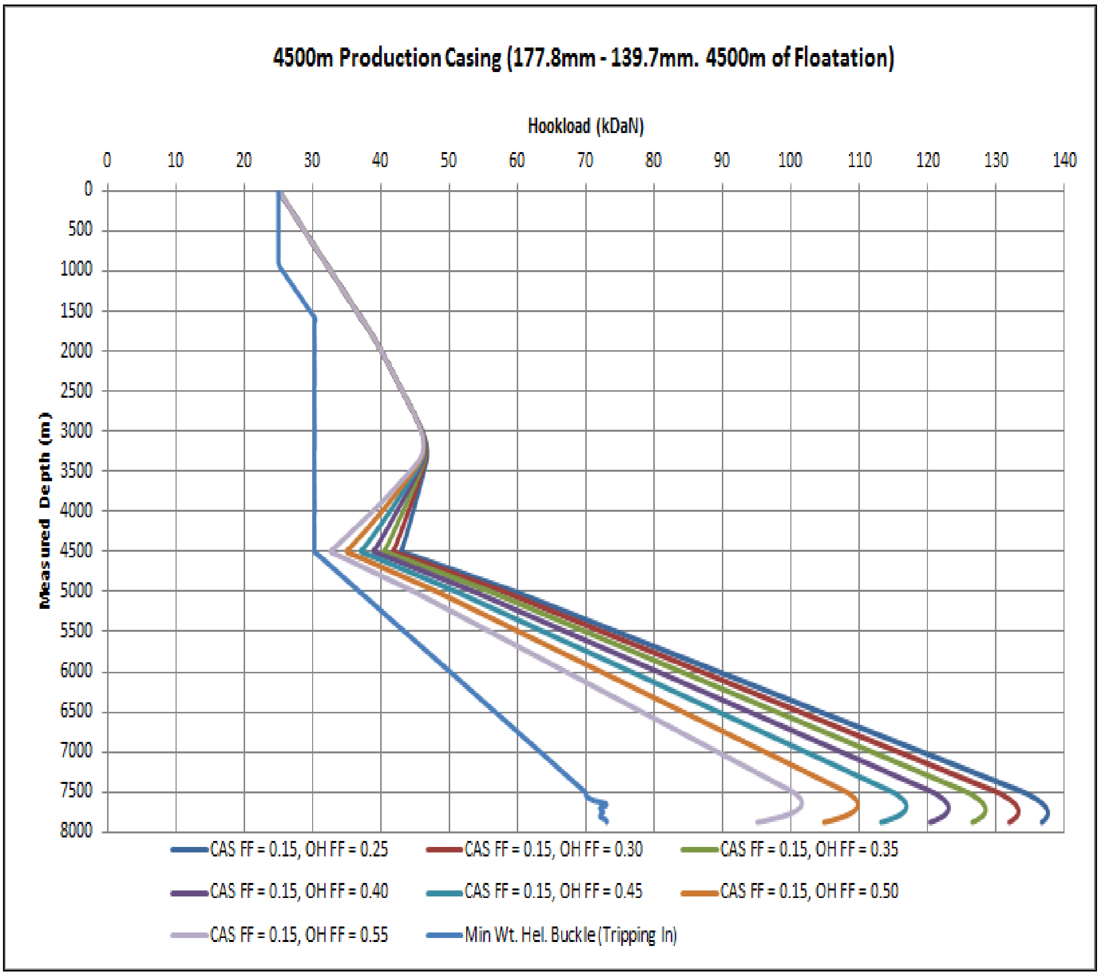

Figure 4.31 Drag for a 4500m Production Casing Run (177.8mm – 139.7mm, 4500m of Floatation)

4.7.2 BHA Design (4500m)

For the 4500m design in a 200mm hole a rotary steerable system, and motor will be run as was planned for the 4000m design. The torque requirement on the 4500m well will be higher than on any previous well drilled in the Duvernay. At TD while drilling with 6000 N-m of torque at the bit the torque at surface should be 31,000 N-m and the hook load to trip the BHA out of the hole with a 0.45 open hole friction factor will be 182kDaN. The drill pipe will be 127mm 29.02 kg/m S-135 grade with a NC50 tool joint with a max OD of 168mm suitable for a 200mm hole. The make-up torque is 41,623 Nm and a tensile rating of the pipe is 250 kDaN which will be sufficient for drilling and tripping out of the hole. If the torque is higher than expected when approaching TD and it rises close to 33,300 N-m (80% of the make-up torque of the drill pipe) then the weight on bit will need to be reduced for the last 500m in order to reduce the torque on the drill string. The 127mm drill pipe will allow for better hole cleaning and less pressure drop than if 114.3mm drill pipe were to be used in the 200mm hole. It will also reduce stick slip while drilling improving drilling performance and improving bit life. Table 4.27 below summarizes the bottom hole assembly (BHA).

Table 4.27 Drilling BHA for Lateral Section on a 4500m Duvernay Well

4500m BHA Description
200mm PDC Bit
175mm Powerdrive RSS
165mm 7/8 3.0 HR Straight Housing Motor with 193.7mm Stabilizer
Short Pulse High Flow
193.7mm stabilizer
165mm NMDC (2 joints)
Crossover
127mm 29.02kg/m S-135 NC50 Drill Pipe to Surface

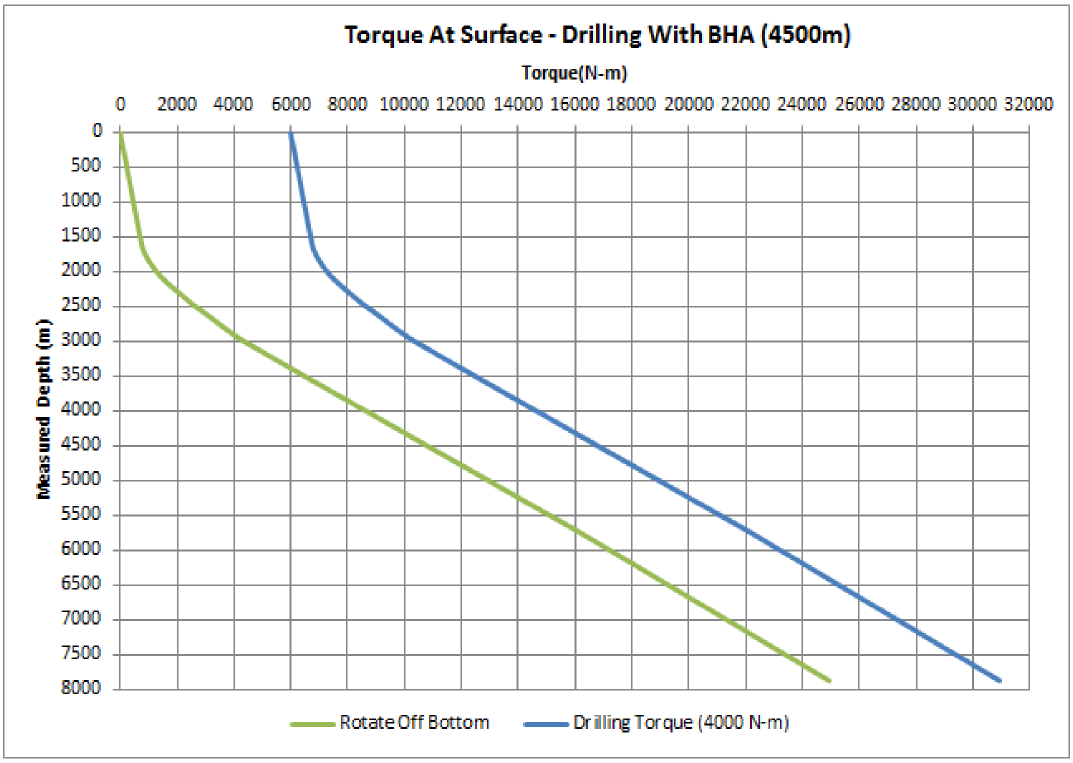

Figure 4.32 Drilling Torque Required for a 4500m Lateral

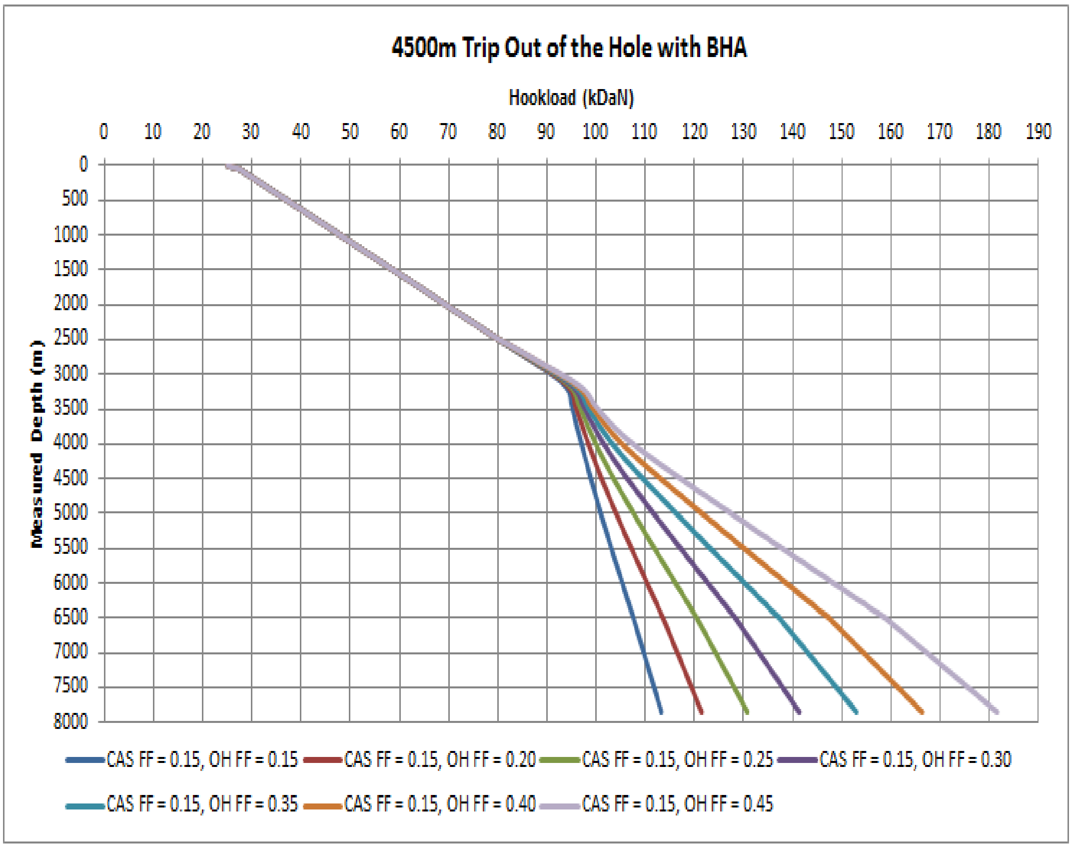

Figure 4.33 Drag Chart for Trip Out of Hole with Drilling BHA on 4500m Lateral

4.7.3 Drilling Fluid Hydraulics (4500m)

The planned pump rate while drilling will be 1.8m3/min and at a total depth of 7874m this will give a total pressure drop through the system of 37,400kpa plus 5,000 kpa differential pressure across the motor and 750kpa across the RSS tool making the total pump pressure while drilling 43,150kpa at TD. The equivalent circulating density (ECD) for the formation at 7874 with cuttings in the annulus will be 1607 kg/m3 which is much lower than what was seen even on the shorter 171mm laterals with 114.3mm drill pipe. This is because the larger 200mm hole creates less pressure drop in the annulus compared to the 171mm hole.

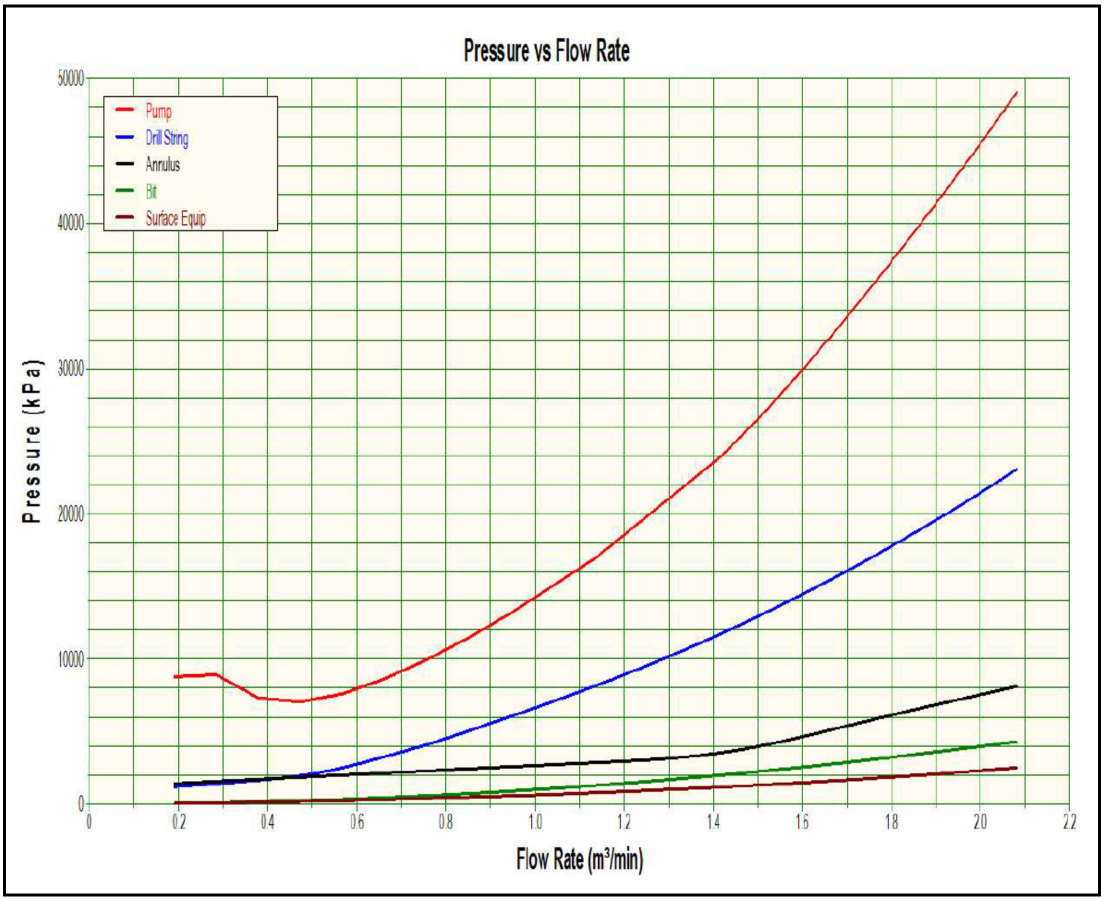

Figure 4.34 Hydraulics Modeling with BHA at TD on a 4500m Well

4.7.4 Cement Job (4500m)

For the 4500m cement job on the tapered casing string it is possible to run the same conventional cement blend as was run on the 2000m and 2500m laterals due to the larger annular clearance. The cementing ECDs remain low throughout the job, and a constant pumping and displacement rate of 1.0m3/min can be maintained throughout the job simplifying the operation.

Table 4.28 4500m Cement Job Design

Fluid	Density	Volume	Position in Annulus
Spacer	1450kg/m3	20.0 m3	Surface – 1500m
Lead Cement	1600 kg/m3	12.0 m3	1500m – 2500m
Tail Cement	1750 kg/m3	85.9 m3	2500m – 7874m

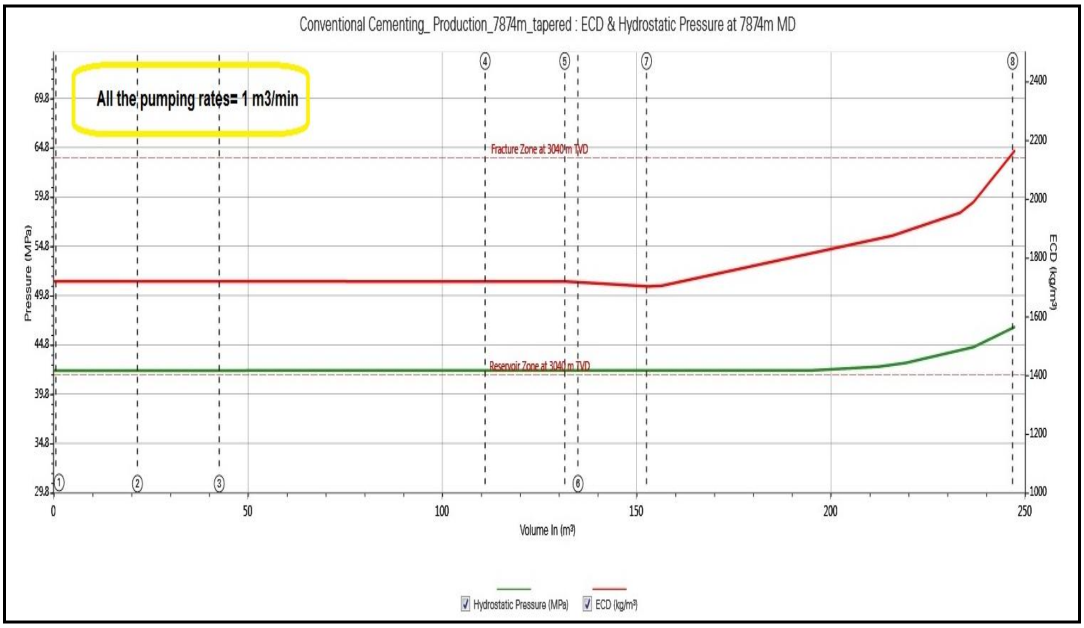

Figure 4.35 Cementing ECDs 4500m Lateral (Regular Cement 1600/1750)

4.7.5 Rig Recommendations (4500m lateral)

Table 4.29 Rig Recommendations for a 4500m Lateral

Hook Load	**232,000 daN** (50,000 daN more than the required hook load to trip out the BHA from TD with a 0.45 friction factor.)
Top Drive Drilling Torque	**33,300 N-m (80% of the makeup torque of the DP)**
Blow Out Preventer (BOP)	**34,500 kPa (based on reservoir pressure)**
Pump Pressure	**45,150 kPa (2000kpa above planned drilling pressure)** It would be beneficial to have a rig with higher pressure capabilities but it is not a requirement.

4.7.6 Cost Estimate (4500m)

The estimated average cost for drilling a 4500m well on an 8 well development pad with the design in this thesis will be $7,800,000 CAD. The cost for the outer wells will be slightly higher than the inner wells on the pad due to the additional distance to the heel and higher drag in the lateral, but an average cost of $7,800,000/well for all wells on the pad will be applied for running the development economics. The completion cost will be $10,730,000/well which assuming that the 500m closest to the toe is completed with 3 clusters per stage allowing for reduced pump rates due to pressure limitations. The next 1000m will be completed with 4 clusters/ stage, the following 1000mm will be completed with 5 clusters/stage, and remaining 2000m closest to the heel are completed with 6 clusters per stage . The lease construction and tie in costs are split evenly across every well on the pad and are estimated $600,000/well. This brings the total cost to drill complete and tie in a 4500m horizontal well on an 8 well pad to $19,130,000/well

Chapter 5

5. Duvernay Lateral Length Economics

By utilizing the Duvernay well design concepts for each lateral length, and matching them with their estimated development cost and production forecast it is found that the optimum design for maximizing the Net Present Value (NPV) of the Duvernay is between 3000m and 3500m depending on the lateral length scaling factors used. This is longer than the current 2200m development concept for the Duvernay so it creates a business case for increasing the lateral for the wells going forward.

5.1 Lateral Length Production Scaling

Assuming equal completion parameters along the well theoretically the drainage area of a well increases linearly with length, and consequently production and Estimated Ultimate Recovery (EUR) should as well. However in practice, deviations from the linear trend do occur. Field development optimization with varying well length has to take into account the possible changes in productivity with well length. According to the paper "Estimated Ultimate Recovery (EUR) Lateral Length Scaling" by Ramesh Mudunri, there are a number of factors which affect the productivity with lateral length which are listed below:

- "There will be a decrease in stimulation efficiency towards the toe of the well. As pressures and pump rates are very high during stimulation, friction losses can be considerable. Pressure limitations at surface will lead to frac pressures at the toe that are lower than those at the heel. This can influence the effectiveness of the completion which is aimed at creating equal hydraulic fractures at each perforation cluster.

- Fracturing fluid clean-up can be different for longer laterals, with improved clean-up for heel sections and reduced clean-up for toe section.
- Retention time of frac fluids will be longer for the toe stages in long laterals. Though the impact of retention time is not completely understood, in general this is considered to be negative.
- Bottom hole pressure (FBHP) could increase with lateral length as friction losses increase with higher total well flow rate. In addition, initial production rates can be outflow / tubing constrained, leading to lower initial rates per meter of lateral length.
- Well undulations could result in portions of the well accumulating liquids restricting the flow of hydrocarbons.
- Tubular design must be consistent with higher rates expected from longer laterals. Constrained production through under designed tubulars can lead to early time underperformance of longer laterals possibly leading to a lower scaling factor for IP.
- Due to hydrocarbon fluid mobility considerations a higher frac conductivity threshold is required for oil as compared to dry gas. Therefore, the deviation from linear lateral length scaling is expected to be larger for oil reservoirs, typically resulting in smaller scaling factors for oil when compared to gas. “

The decreased stimulation efficiency with increasing length is considered to be the dominant factor leading to diminishing production and EUR.

5.2 Duvernay Production Scaling - Fox Creek 19 Production Results

Table 5.1 Fox Creek 19 Production Results

	(FC19A) 12-27-62-18W5	FC19B 11-27-62-18W5	FC19C 7-34-63-18W5	FC19D 8-34-63-18W5
Total Oil+ Condensate to Date (boe)	25381	22679	22341	15219
Total Gas to Date (boe)	13508	10257	10138	6456
Total Production (boe)	38889	32935	32479	21675
Completed Lateral Length (m)	2541	2464	1617	1598
Cluster Spacing (m)	34	34	20	34
Lateral Length/FC19D	1.5901	1.5419		
Production / FC19D	1.794199726	1.519511558		
Lateral Length Production Scaling Factor to FC19D	1.128356535	0.985479965		
Average Production Scaling Factor to FC19D	1.05691825			

The production results from the Fox Creek 19 pad indicate a near linear correlation between lateral length and production between FC19A and FC19B when compared to FC19D. These wells were all completed with the same completion strategy having 34m cluster spacing where FC19C was completed with a more aggressive 20m cluster spacing so it is not being used for this comparison. During the completion every well on the pad pumped the same amount of fluid and proppant per cluster. It can be seen that having more clusters and pumping more fluid and sand created a substantial uplift in production for FC19C when compared to FC19D, however optimal completion design is outside the scope of this thesis. This pad has only been on full production since April 2014 so the effect which lateral length has on long term production, furthermore there are differences in reservoir quality even across a single pad so more information is needed in order to fully quantify the effects of lateral length in the Duvernay.

5.3 Bakken Lateral Length Production Scaling

The Bakken is an unconventional light tight oil formation very similar in many geological properties to the Duvernay so it will be a good analog for gathering larger sample of production data in order to make a prediction of the long term EUR effects of lateral length in the Duvernay.

A study by Forward Energy titled “Fox Creek External Competitor Analysis” looked at production performance data from the Slawson Exploration area of the Bakken Play in North Dakota. In this area, 11 long wells with an average treated length of 9,100 ft were compared against 23 short wells with an average treated length of 4,500 ft. Average stage length, sand per stage and fluid per stage area very comparable between the two groups. Decline-curve analysis indicated EURs of 784 and 445 kbbl for the long and short wells, respectively, resulting in a 76% uplift for the 9100 ft wells compared to the 4500 ft wells in the Bakken resulting in a lateral length scaling factor of 0.75.

5.4 Duvernay Long Lateral Economic Results

When doing the lateral length production scaling for the Duvernay the base case production type curve will be based on a 2000m lateral. The medium case lateral length scaling factor from 2000m up to 3000m will be 0.75 which is based on the results seen from the Bakken and this will be given a sensitivity of ± 0.15 for the high and low case production scaling scenarios.

There is very little long term production data or scaling information in the industry from unconventional oil wells between 3000m and 4500m. There will be a diminishing rate of production with length so for the purposes of this thesis it will be assumed that the EUR for every 500m interval past 3000m will have a scaling factor which decreases by 0.10. The production scaling factors used for the economic analysis are summarized in Table 5.2.

Table 5.2 Lateral Length Production Scaling Factors for the Duvernay

Lateral Range	2000m - 3000m	3000m - 3500m	3500m - 4000m	4000m - 4500m
High Case	0.90	0.80	0.70	0.60
Medium Case	0.75	0.65	0.55	0.45
Low Case	0.60	0.50	0.40	0.30

The single well cost includes the cost for drilling, completions and tie in (DCT). All taxes and operating costs for the well throughout the lifecycle are accounted for. The initial land acquisition costs are not taken into account in this economic analysis. The production type curve for a 2000m well in the Duvernay is scaled in accordance with the lateral length of each development concept and future production is discounted at a rate of 15% in order to determine the Net Present Value of each well. The actual production type curve information for the region of T63-R20-W5M is confidential and cannot be published; however the results from the economic analysis are summarized in Table 5.3. The Value Investment Ratio (VIR) is the ratio of the NPV to the total cost of each well (DCT) and is indicative of the rate of return on the investment for a single well.

The economic results are summarized below in Table 5.3 and it can be seen that in the high case the maximum NPV and VIR is for a 3500m lateral, and beyond that point the increased capital cost outweighs the value of the additional production. In the medium case the NPV is the highest for a 3500m lateral, however the VIR is the highest for a 3000m lateral. This indicates that the incremental production of a 3500m lateral over a 3000m lateral is more valuable than the added cost, however the rate of return of that incremental investment is lower than the return for the first 3000m and as a result the VIR decreases. In the low case for lateral length production scaling the optimum lateral length is 3000m.

Table 5.3 Duvernay Lateral Length - Single Well Economics

High Case								
Length	**EUR Scaling Factor**	**EUR (mboe)**	**Drill Cost K$**	**Comp Cost K$**	**Tie-in Cost K$**	**DCT**	**NPV K$**	**VIR**
2000		536	3,900	4,600	600	9100	$5,733	0.6300
2500	0.90	657	4,100	5,700	600	10400	$8,131	0.7818
3000	0.90	775	4,450	6,780	600	11830	$10,745	0.9083
3500	0.80	878	5,000	8,110	600	13710	**$12,734**	**0.9288**
4000	0.70	966	7,000	9,400	600	17000	$11,977	0.7045
4500	0.60	1038	7,800	10,730	600	19130	$11,535	0.6030
Medium Case								
Length	**EUR Scaling Factor**	**EUR (mboe)**	**Drill Cost K$**	**Comp Cost K$**	**Tie-in Cost K$**	**DCT**	**NPV K$**	**VIR**
2000		536	3,900	4,600	600	9100	$5,733	0.6300
2500	0.75	637	4,100	5,700	600	10400	$7,546	0.7255
3000	0.75	732	4,450	6,780	600	11830	$9,327	**0.7884**
3500	0.65	811	5,000	8,110	600	13710	**$10,170**	0.7418
4000	0.55	875	7,000	9,400	600	17000	$7,653	0.4502
4500	0.45	924	7,800	10,730	600	19130	$5,426	0.2836
Low Case								
Length	**EUR Scaling Factor**	**EUR (mboe)**	**Drill Cost K$**	**Comp Cost K$**	**Tie-in Cost K$**	**DCT**	**NPV K$**	**VIR**
2000		536	3,900	4,600	600	9100	$5,733	0.6300
2500	0.60	616	4,100	5,700	600	10400	$6,961	0.6693
3000	0.60	690	4,450	6,780	600	11830	**$7,950**	**0.6720**
3500	0.50	748	5,000	8,110	600	13710	$7,738	0.5644
4000	0.40	791	7,000	9,400	600	17000	$3,638	0.2140
4500	0.30	820	7,800	10,730	600	19130	-$139	-0.007

Chapter 6

6. Conclusion

To date the longest well drilled by Shell in the Duvernay formation had a lateral length of 2500m. By applying the lessons learnt from the long lateral trials in the Duvernay and in Groundbirch trials it should be technically feasible to drill a Duvernay well up to a lateral length of 4500m. The main technical enablers in this thesis for delivering long lateral wells are optimized directional plans, rotary steerable drilling assemblies, casing floatation, tapered or upsized production casing strings in the vertical section and foam cement jobs. Well design requirements will differ between unconventional oil and gas fields, but these technical enablers when applied appropriately can also be utilized to increase lateral length in fields other than the Duvernay.

The incremental cost per meter increases with lateral length and eventually gets to a point of diminishing returns. By understanding the economic impact which lateral length has on a wells economics, field development planning can maximize the use of certain lengths in order to optimize the Net Present Value of the Duvernay.

6.1 Findings and Recommendations

It can be seen in Table 5.3 that in every lateral length scaling scenario the NPV and VIR improve by increasing the lateral length from 2000m to 3000m. Depending on the lateral length scaling numbers, the optimum lateral length should be somewhere between 3000m and 3500m. The 3000m and 3500m well designs consist of a 139.7mm monobore design in a 171mm hole. Both of those designs required a rotary steerable system in order to drill the lateral section to TD, they required casing floatation in order to get casing to bottom, and they required foam cement to stay below the fracture gradient at the toe while maintaining sufficient flow rates to get a quality cement job. They also required a rig with larger capacities for hook load, torque and pump pressure then what is currently required for developing 2000m laterals. Even though these technical requirements add cost to the well, the added production from increased length improves the NPV and VIR for these development concepts over the standard 2000m design.

The added cost of drilling a 4000m or a 4500m well is greater than the increased production even in the high EUR scaling factor case. Increasing the lateral length to 4000m requires a 177.8mm by 139.7mm tapered casing design with floatation to get casing to bottom. There is a substantial cost increase with upsizing all the hole and casing sizes throughout the well, and as a result this decreases the NPV and VIR in all EUR production scaling scenarios.

The key enablers for delivering long laterals are optimized directional plans, rotary steerable drilling assemblies, friction reduction pills, casing floatation, tapered production casing strings, foam cement and a drilling rig with sufficient hook load, torque and pump pressure. These key enablers when properly implemented can be used to increase the lateral length for any unconventional oil and gas field. The optimum lateral length will differ between different fields due to changes in the total vertical depth, required number of casing strings, reservoir pressures, fracture gradients, lateral length production scaling factors and many other geological conditions. After properly understanding the technical requirements to enable longer laterals for a particular field the economics need to be run in order to assess the optimum lateral length on a case by case basis.

For the Duvernay I recommend changing the development strategy to maximize the use of 3000m wells which will improve the development economics immediately. As production data is gathered from more long laterals in the Duvernay the lateral length scaling factors will be better understood. After gaining experience consistently executing 3000m laterals with the use of RSS, casing floatation, and foam cement I recommend recalculating the economics for a 3500m well and pursuing it only if it will further optimize the overall Net Present Value of the Duvernay.

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