WD-03

Application for Permit to Drill Document

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1. Well Name *(Requirements of 20 AAC 25.005 (f))*

The well for which this application is submitted will be designated as WD-03

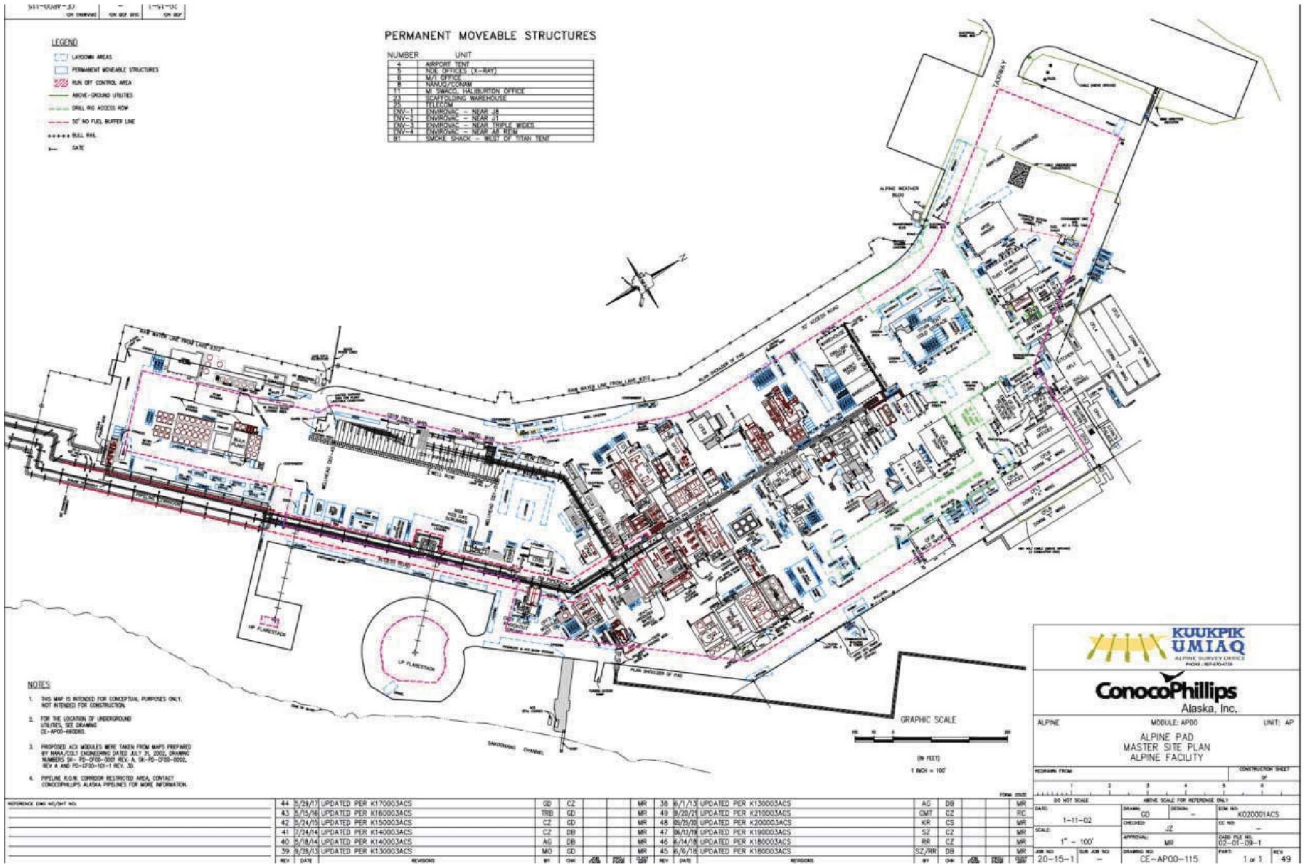
2. Location Summary *(Requirements of 20 AAC 25.005(c)(2))*

Location at Surface	574' FNL, 2229' FWL, S5 T11N R5E, UM	
NAD 1927	*RKB Elevation*	58.5' AMSL
Northings: 385653	*Pad Elevation*	19.5' AMSL
Eastings: 5975557		

Top of Productive Horizon (Heel)	2730' FNL, 68' FWL , S5 T11N R5E, UM	
NAD 1927	*Measured Depth, RKB:*	9449'
Northings: 383466	*Total Vertical Depth, RKB:*	8745'
Eastings: 5973434	*Total Vertical Depth, SS:*	8687'

Total Depth (Toe)	2730' FNL, 68' FWL, S5 T11N R5E, UM	
NAD 1927	*Measured Depth, RKB:*	10543'
Northings: 383466	*Total Vertical Depth, RKB:*	9840'
Eastings: 5973434	*Total Vertical Depth, SS:*	9781'

Pad Layout



3. Proposed Drilling Program

The proposed drilling program is listed below. Please refer to Attachment 3: Completion Schematic.

1. MIRU Doyon 142 onto WD-03
2. Rig up and test riser, dewater cellar as needed.
3. Drill 16" hole to the surface casing point as per the directional plan (LWD Program: GR).
4. Run and cement 13.375" surface casing to surface.
5. Install BOPE and MPD equipment.
6. Test BOPE to 250 psi low / 4,500 psi high (24-48 hr regulatory notice).
7. Pick up and run in hole with 9-7/8 x 11" drilling BHA to drill the intermediate hole section. Log cement on trip in utilizing Sonic in record mode.
8. Chart casing pressure test to ~~4200~~ 3,500 psi for 30 minutes.
9. Drill out 20' of new hole and perform FIT/LOT. Maximum FIT to 17 ppg. Minimum LOT required to drill ahead is 14.5 ppg EMW.
10. Drill 9-7/8 x 11" hole to section to the top of the Alpine C.
11. TOOH and perform wireline logging runs.
12. TIH and drill 9-7/8 x 11" hole to section TD, using Managed Pressure Drilling to maintain near constant bottom hole pressure on connections in shale formation (LWD Program: GR/RES/Den/Neut/Por).
13. Change out upper pipe rams to 7.625" solid bodies and test same 4,500 psi.
14. Run 7.625" casing and cement to 250' TVD/500' MD above the hydrocarbon bearing zones (cementing schematic attached). Run CBL to determine TOC and cement quality. Interpretation and log to AOGCC as soon as available.
15. Change upper pipe rams to 3-1/2" x 6" VBRs.
16. Test BOPE to 250 psi low / 4,500 psi high (24-48 Regulatory notice).
17. Pick up and run in hole with 6.75" drilling BHA. Log top of cement with sonic tool in recorded mode.
18. Chart casing pressure test to 4200 psi for 30 minutes.
19. Drill out shoe track and 20 feet of new formation. Perform FIT/LOT to a maximum of 13 ppg. Minimum required leak-off value is 10.2 ppg EMW.
20. Drill 6.75" hole to section TD (LWD Program: GR/RES).
21. Pull out of hole with drilling BHA. Review cement job details and sonic log TOC.
22. Run 5.5" liner to TD and cement in place. Set liner top packer and circulate out excess cement. Displace mud to corrosion inhibited brine.
23. OWFF for 30 min and TOOH.
24. Test 5-1/2" liner to 4,200 psi for 30 minutes.
25. Rig up E-line and run CBL for 5-1/2" liner cement job.
26. Pick up TCP perf assembly and RIH on 4" drill pipe. Correlate on depth and perforate interval. Monitor 30 min to confirm static well. TOOH and inspect perf guns.
27. PU and run 4-1/2" completion c/w downhole gauge. Space out and land tubing hanger. Pressure test tubing hanger seals to 5,000 psi for 30 min. Drop ball and rod, pressure up to set packer.
28. Pressure test tubing to 4,200 psi for 30 min. Pressure test 7" x 4-1/2" annulus to 4,200 psi for 30 min.
29. Shear SOV. Install BPV and test to 2,500psi from below.

Per M. Smith email dated 11/30/21, directional survey data will be recorded at a maximum of every 100' for entire well, and more frequently if necessary.
SFD 12/1/2021

Per M. Smith email dated 11/30/21, surface casing will be tested to 3500 psi.
SFD 12/1/2021

30. Nipple down BOP and NU tree and tubing head adapter assembly. Pressure test adapter to 5,000 psi. Install BPV dart and test tree to 5,000psi.
31. Pull BPV and freeze protect tubing and IA to 1100 ft MD with diesel by u-tubing.
32. Secure well. Rig down and move out.

4. Diverter and Blowout Prevention Equipment *(Requirements of 20 AAC 25.005(c)(7))*

Please reference BOP schematic on file for Doyon 142

It is requested that a variance of the diverter requirement under 20 AAC 25.035 (h)(2) is granted. At CD1, there has not been a significant indication of shallow gas or gas hydrates through the surface hole interval. There are 4 previously drilled wells (CD1-34, CD1-38, CD1-39, CD1-41) within 500' of the proposed WD-03 surface shoe location. None of these wells encountered any significant indication of shallow gas or gas hydrates.

Diverter requirement variance is reasonable based on additional information provided in attached email from Matt Smith, CPAI, dated 12/7/2021. SFD 12/7/2021

5. MASP Calculations

The following presents data used for calculation of anticipated surface pressure (ASP) during drilling of this well:

Casing Size (in)	Csg Setting Depth MD/TVD(ft)	Fracture Gradient (ppg)	Pore pressure (psi)	ASP Drilling (psi)
20	120 / 120	10.9	51	54
13.375	2468/ 2372	16	1043	1736
7.625	9449/ 8745	15.8	5,002	3877
5.5	10543/ 9840	12.9	4,398	n/a

11.0 ppg EMW
SFD 12/7/2021

PROCEDURE FOR CALCULATING ANTICPATED SURFACE PRESSURE (ASP)

ASP is determined as the lesser of 1) surface pressure at breakdown of the formation casing seat with a gas gradient to the surface, or 2) formation pore pressure at the next casing point less a gas gradient to the surface as follows:

1) ASP = [(FG x 0.052) - 0.1]*D

Where: ASP = Anticipated Surface pressure in psi
FG = Fracture gradient at the casing seat in lb/gal
0.052 = Conversion from lb./gal to psi/ft
0.1 = Gas gradient in psi/ft
D = true Vertical depth of casing seat in ft RKB

OR

2) ASP = FPP – (0.1 x D)

Where: FPP = Formation Pore Pressure at the next casing point
FPP = 0.4525 x TVD

1. ASP CALCULATIONS

1. **Drilling below 20" conductor**

ASP = [(FG x 0.052) – 0.1] D
= [(10.9 x 0.052) – 0.1] x 120 = 54 psi

OR

ASP = FPP – (0.1 x D)
= 1043 – (0.1 x 2372) = 824 psi

2. **Drilling below 13.375" surface casing**

ASP = [(FG x 0.052) – 0.1] D
= [(16 x 0.052) – 0.1] x 2372= 1736 psi

OR

ASP = FPP – (0.1 x D)
= 5002 – (0.1 x 8745) = 4128 psi

3. **Drilling below 7.625" intermediate casing**

ASP = [(FG x 0.052) – 0.1] D
= [(12.9 x 0.052) – 0.1] x 8745= 6311 psi

OR

ASP = FPP – (0.1 x D)
= ~~4400~~ – (0.1 x 9840) = 3877 psi
4,861

SFD 12/1/2021

(B) data on potential gas zones;

The well bore is not expected to penetrate any gas zones.

(C) data concerning potential causes of hole problems such as abnormally geo-pressured strata, lost circulation zones, and zones that have a propensity for differential sticking;

Please see Drilling Hazards Summary

6. Procedure for Conducting Formation Integrity Tests *(Requirements of 20 AAC 25.005 (c)(5))*

Drill out surface casing shoe and perform LOT test or FIT in accordance with the Alpine LOT/FIT procedure that ConocoPhillips Alaska has on file with the Commission.

7. Casing and Cementing Program

Casing and Cementing Program					
Csg/Tbg OD (in)	*Hole Size (in)*	*Weight (lb/ft)*	*Grade*	*Conn.*	*Cement Program*
20	42	94	H-40	Welded	Cemented to surface with 10 yds slurry
13.375	16	68	L-80	Hyd563	Cement to Surface
7.625	9-7/8 x 11	29.7	L80	TXP	500' MD above Kuparuk C, Qannik (if necessary)
5.5	6.75	15.5	L-80	Hyd511	Cemented liner
4.5		12.6	L-80	Hyd563	Tubing

A variance for the packer depth for injection wells under 20 AAC 25.412 (b) is also requested that it may be located greater than 200 feet measured depth from above the top of the perforations, but shall not be located above the confining zone, and shall have outer casing cement volume sufficient to place cement a minimum of 300 feet measured depth above the planned packer depth. The confining zone for the injection interval is the Kingak formation which is greater than 1600 ft thick.

Cementing Calculations

13.375" Surface Casing run to 2468' MD / 2372' TVD

Cement from 2468' MD to 1968' (500' of tail) with Class G + Add's. @ 11 PPG, and from 1968' to surface with 11 ppg DeepCrete. Assume 250% excess annular volume in permafrost and 50% excess below the permafrost (890' MD), zero excess in 20" conductor.

Lead slurry from 1968' MD to surface with Arctic Lite Crete @ 11 ppg
Total Volume = 2897 ft^3 => **1510 sx of 11ppg Class G + Add's @ 1.92 ft^3 /sk**
Tail slurry from 2468' MD to 1968' MD with 15.8 ppg Class G + Add's
Total Volume = 349 ft^3 => **310.0 sx of 15.8 ppg Class G + Add's @ 1.16 ft^3/sk**

7.625" Intermediate Casing run to 9449' MD / 8745' TVD

Top of first stage slurry is designed to be at 7110' MD, which is 500'MD above the prognosis hydrocarbon bearing zone Kuparuk. If reservoir quality Qannik is encountered, a 2nd stage cement job will be performed as outlined below through the use of a stage tool. Assume 40% excess annular volume.

See Qannik reservoir quality criteria in attached email from M.Smith dated 11/30/2021. SFD 12/1/2021

Lead slurry from 8949' MD to 7110'MD with Class G + Add's @ 12ppg
Total Volume = 883 **ft3 => 500 sx of 12 ppg Class G + Add's @ 1.78 ft3 /sk**
Tail slurry from 9449' MD to 8949' MD with 15.8 ppg Class G + Add's
Total Volume = **261** ft^3 => **230 sx of 15.8 ppg Class G + Add's@ 1.16 ft^3/sk**

Intermediate 2nd stage cement job (if necessary)

Tail slurry from 4800' MD to 3800' MD with 15.8 ppg Class G + Add's
Total Volume = 480 ft^3 => **420 sx of 15.8 ppg Class G + Add's@ 1.16 ft^3/sk**

5.5" Production Liner run to 10543' MD / 9840' TVD

Top of slurry is designed to be at 9249' MD, which is at the liner top, which will be set ~200' MD inside the Intermediate 1 casing shoe. Assume 40% excess annular volume.

Tail slurry from 10543' MD to 9249' MD with 15.8 **ppg Class G + Add's**
Total Volume = 151 ft^3 => **140 sx of** 15.8 **ppg Class G + Add's@** 1.16 **ft^3/sk**

8. Drilling Fluid Program *(Requirements of 20 AAC 25.005(c)(8))*

		Surface	Intermediate	Production
Hole Size	in.	16	9-7/8 x 11	6.75
Casing Size	in.	13.375	7.625	5.5
Density	PPG	9.0 – 10.0	10.5 - 11.5	9.5 – 10.5

PV	cP	30 - 80	10	10
YP	lb./100 ft^2	100 - 200	20 - 28	10 - 15
Funnel Viscosity	s/qt.	300	50 - 60	40 - 50
Initial Gels	lb./100 ft^2	50	10	6
10 Minute Gels	lb./100 ft^2	60	15	8
API Fluid Loss	cc/30 min.	N.C. – 15.0	5.0	4.0
HPHT Fluid Loss	cc/30 min.	n/a	8.0 – 12.0	10.0
pH		11.0	9.5 – 10.0	9.0 – 9.5

Surface Hole:

A mixed-metal oxide fresh water drilling fluid (Drilplex) will be used for the surface interval. Keep flow line viscosity at ± 300 sec/qt while drilling permafrost and ± 150-200 sec/qt to TD and for running casing. Reduce viscosity prior to cementing. Maintain mud weight ≤10.0 ppg by use of solids control system and dilutions where necessary.

Intermediate:

Fresh water polymer mud system. Ensure good hole cleaning by pumping regular sweeps and maximizing fluid annular velocity. There is a slight potential for lost circulation, particularly after the reservoir is penetrated. Maintain mud weight at ~11.0 ppg for formation stability and be prepared to add loss circulation material if necessary. Good filter cake quality, hole cleaning and maintenance of low drill solids (by diluting as required) will all be important in maintaining wellbore stability. The mud will be weighted up to ~11.5 – 11.8 ppg before pulling out of the hole.
Note: Managed Pressure Drilling (MPD) will be utilized for adding backpressure during connections to mitigate shale instability and cycling.

Production Hole:

The production interval will be drilled with a water-based mud drill-in fluid (FloPro) weighted to ~10 ppg with calcium carbonate and KCl and utilize MPD for monitoring pressure on connections.

Diagram of Doyon 142 Mud System on file.

Drilling fluid practices will be in accordance with appropriate regulations stated in 20 AAC 25.033.

9. Abnormally Pressured Formation Information *(Requirements of 20 AAC 25.005 (c)(9))*

The Alpine C has the potential to be over pressured, due to years of offset injection support at CD1. Offset wells have been shut in, and flowbacks occurring to reduce bottom hole pressure as much as possible. Continued monitoring prior to spud.

10. Seismic Analysis *(Requirements of 20 AAC 25.005 (c)(10))*

N/A - Application is not for an exploratory or stratigraphic test well.

11. Seabed Condition Analysis *(Requirements of 20 AAC 25.005 (c)(11))*

N/A - Application is not for an offshore well.

12. Evidence of Bonding *(Requirements of 20 AAC 25.005 (c)(12))*

Evidence of bonding for ConocoPhillips Alaska, Inc. is on file with the Commission.

13. Discussion of Mud and Cuttings Disposal and Annular Disposal

(Requirements of 20 AAC 25.005 (c)(14))

Incidental fluids developed from drilling operations on well **WD-03** will be injected into the Class 1 disposal well on CD1.

The **WD-03** surface/intermediate casing annulus will be flushed with 300 bbls of fresh water prior to freeze protecting with diesel to ~200' TVD below the base of permafrost, ~1200'. Significant hydrocarbon zones include only the Alpine sand based on pre-drill interpretations. There will be 500' of cement placed above the top of the Kuparuk reservoir, and a 2nd stage cement job will be performed as necessary if reservoir quality Qannik is encountered while drilling, to isolate.

Once **WD-03** has been drilled and completed an application for Sundry Operations form 10-403 will then be filed.

Surface casing will be set near the base of the C40 formation, above the C30. These 450-500' thick shales are part of the Colville Group and are known to provide vertical barriers to fluid flow in other areas.

14. Drilling Hazards Summary

(To be posted in Rig Floor Doghouse Prior to Spud)

16" Hole / 13.375" Casing Interval

Event	Risk Level	Mitigation Strategy
Conductor Broach	Low	Monitor cellar continuously during interval.
Well Collision	Low	First well on Pad, traveling cylinder diagrams
Gas Hydrates	Low	If observed – control drill, reduce pump rates and circulating time, reduce mud temperatures
Clay Balling	Medium	Maintain planned mud parameters and flow rates, Increase mud weight, use weighted sweeps, reduce fluid viscosity, control ROP
Running gravels	Medium	Increased mud weight, sweeps, maintain fluid rheology and control pump rtes
Lost Circulation	Medium	Reduce pump rates, mud rheology, add lost circulation material, use of low density cement slurries, port collar, control pipe running speeds

9-7/8 x 11" Hole /7.625" Casing - Casing Interval

Event	Risk Level	Mitigation Strategy
Sloughing shale, Tight hole	High	MPD for shale stability, Steerable Drilling Liner, Increase mud weight, control ROP, connection and trip speeds, sweeps, and real time equivalent circulating density (ECD) monitoring, run casing as liner
Lost circulation	Low	Reduce pump rates, reduce trip speeds, real time ECD monitoring, mud rheology, add lost circulation material
Hole swabbing on trips	Medium	Reduce trip speeds, condition mud properties, proper hole filling, pump out of hole, real time ECD monitoring, Liner will be in place at TD
Abnormal Reservoir Pressure	Medium	Well control drills, check for flow during connections, increase mud weight
Hydrogen Sulfide gas	Low	H_2S drills, detection systems, alarms, standard well control practices, mud scavengers

6.75" Hole / 5.5" Liner - Production Hole

Event	Risk Level	Mitigation Strategy
Lost circulation	Low	Reduce pump rates, reduce trip speeds, real time ECD monitoring, mud rheology, add lost circulation material
Hole swabbing on trips	Medium	Reduce trip speeds, condition mud properties, proper hole filling, pump out of hole, real time ECD monitoring
Abnormal Reservoir Pressure	Low	Well control drills, check for flow during connections, increased mud weight

Differential Sticking	Low	Uniform reservoir pressure along lateral, keep pipe moving, control mud weight
Hydrogen Sulfide gas	Low	H_2S drills, detection systems, alarms, standard well control practices, mud scavengers

Well Proximity Risks:

WD-03 will be the 50th well drilled on CD1 pad. On CD1, wellbore spacing is on 10' centers. Close approach to offset CD1-49, CD1-48 and CD1-43 in the surface hole will be mitigated through the use of GWD and real time anti-collision monitoring. These wells will be shut in and bled off prior to drilling this section. Directional drilling / collision avoidance information as required by AOGCC 20 ACC 25.050 (b) is provided in the following attachments.

Drilling Area Risks:

Reservoir Pressure: Offset injection has the potential to increase reservoir pressure in the Alpince C over predicted. The rig will be prepared to weight up if required.

Weak sand stringers could be present in the overburden. LCM material will be available to seal in losses in the intermediate section.

Lower Shale Stability: HRZ/Kalubik/Miluveach/Kingak will require higher mud weights than historically used to enhance wellbore stability. Managed Pressure Drilling along with increased mud weights will be used to mitigate shale instability in the aforementioned formations. Standard LCM material and well bore strengthening pills are expected to be effective in dealing with lost circulation if needed.

Good drilling practices will be stressed to minimize the potential of taking swabbed kicks.

15. Proposed Completion Schematic