30 CFR 250.415(f) Compliance Questionnaire

	GENERAL QUESTIONS	
1.	Have you considered the following in your well planning and drilling plan determinations: evaluation for flow potential, site selection, shallow hazards, deeper hazard contingency planning, well control planning for fluid influxes, planning for lost circulation control, regulatory issues and communications plans, planning the well, pore pressure, fracture gradient, mud weight, casing plan, cementing plan, drilling plan, wellbore hydraulics, wellbore cleaning, barrier design, and contingency planning? [API 65-2 1.5]	Yes
2.	Have you considered the general well practices while drilling, monitoring and maintaining wellbore stability, curing and preventing lost circulation, and planning and operational considerations? [API 65-2 1.6]	Yes
	FLOW POTENTIAL	
3.	Will a pre-spud hazard assessment be conducted for the proposed well site?	Yes
4.	List all potential flow zones within the well section to be cemented	Described Below
5.	Has the information concerning the type, location, and likelihood of potential flow zones been communicated to key parties (cementing service provider, rig contractor, or 3rd parties)?	Yes
	CRITICAL DRILLING FLUID PARAMETERS	
6.	Are fluid densities sufficient to maintain well control without inducing lost circulation?	Yes
	CRITICAL WELL DESIGN PARAMETERS	
7.	Will you use a cementing simulation model in the design of this well?	Yes
7a.	If yes, how is the output of this simulation model used in your decision-making process?	Described Below
7b.	If no, include discussion of why a model is not being used.	NA
7c.	Either way, include the number and placement of centralizers being used.	Described Below
8.	Will you ensure the planned top of cement will be 500’ above the shallowest potential flow zone?	Yes
9.	Have you confirmed that the hole diameter is sufficient to provide adequate centralization?	Yes
10.	If there are any isolated annuli, how have you mitigated thermal casing pressure build-up?	Described Below
11.	Will you ensure the well will be stable (no volume gain or losses, drilling fluid density equal in vs. out) before commencing cementing operations?	Described Below
12.	List all annular mechanical barriers in your design.	Described Below
13.	Has the rat hole length been minimized or filled with drilling fluid with a density greater than the cement density?	Yes
14a.	If you have any liner top packers exposed to the production or intermediate annulus, what is the rating for differential pressure across this packer?	Described Below
14b.	If you have any liner top packers exposed to the production or intermediate annulus, have you confirmed that your negative test will not exceed this rating?	Described Below
15.	What type of casing hanger lock-down mechanisms will be used?	Described Below
16.	For all intermediate and production casing hangers set in subsea, HP wellhead housing, will you immediately set/energize the lock-down ring prior to performing any negative test?	NA Surface Wellhead
17.	For all production casing hangers set in subsea, IIP wellhead housing, will you set/energize the lock-down <u>sleeve</u> immediately after running the casing and prior to performing any negative test?	NA Surface Wellhead
	CRITICAL OPERATIONAL PARAMETERS	

18.	Will you have 2 mechanical barriers in addition to cement in your final casing string (or liner if it is your final string)?	Yes
19.	Do you plan to nipple down BOP in accordance with the WOC requirements in 30 CFR 250.422 and API RP 65 Part 2 First Edition?	Yes
20.	Do you plan on running a cement bond log on the production and intermediate casing/liner prior to conducting the negative test on that string?	Yes Prod' Liner
	Are Contingency Plans In Place For The Following:	
21.	Lost Circulation?	Yes
22.	Unplanned shut-down?	Yes
23.	Unplanned rate change?	Yes
24.	Float equipment does not hold differential pressures?	Yes
25.	Surface equipment issues?	Yes
26.	Will you monitor the annulus during cementing and WOC time?	Yes
27.	If using foam cement, is a risk assessment being conducted and incorporated into cementing plan?	NA
28.	If using foam cement, will the foamer, stabilizer, and nitrogen injection be controlled by an automated process system?	NA
	CRITICAL MUD REMOVAL PARAMETERS	
29.	Have you tested your drilling fluid and cementing fluid programs for compatibility to reduce possible contamination?	Yes, Actual Fluids will be tested
30.	Have you considered actual well conditions when determining appropriate cement volumes?	Yes
31.	Has the spacer been modeled or designed to achieve the best possible mud removal?	Yes
	CRITICAL CEMENT SLURRY PARAMETERS	
32.	Have all appropriate cement slurry parameters been considered to ensure the highest probability of isolating all potential flow zones?	Yes
33.	Do you plan on circulating bottoms up prior to the start of the cement job?	Yes

If any question is answered "No", additional explanation will be needed as to why that practice is not being followed; identify the question and provide that explanation below. The following questions are not "Yes/No" questions and will require a description (if not applicable, state "Not Applicable").

4. The "Cib Carst" sand at 8,085'tvd.

7a The simulation model is utilized to confirm pump rates, ECDs, casing running speed, and minimize swab and surge effects.

The simulation model is utilized to determine the optimum displacement rates to achieve the best possible mud removal during circulating and cementing. It also assists in spacer design to achieve best possible mud removal prior to cementing.

7c. There will be a minimum of six centralizers installed on the bottom five joints of both the 18-5/8" conductor and 13 3/8" surface casing strings. The 9 5/8" intermediate casing will have a minimum 47 centralizers, 2 on the shoe joint and 2 per every three joints or 60' spacing from 8,121' to 6701'. The 5-1/2" liner will be centralized with an estimated 23 centralizers, a minimum of 3 on the first 3 joints, and 1 centralizer per joint from 10,133' to 9318' or ±500' above and below any potential flow zone.

10. This is a surface wellhead, annular pressure will be monitored and bled off as required.

11. It is planned to circulate bottoms up, and that the well would be stable before beginning cementing operations, however, this can not be ensured. In the event that partial or complete returns are lost, it is planned to pump the cement and monitor the annulus.

12. Conductor: Cement + 'Speed Head' Seal in 18-5/8" Casing Hanger.
Surface: Cement + 'Speed Head' Annulus Pack-off in the 13-3/8" Casing Hanger
Intermediate: Cement + 9-5/8" pack-off.
Production" Cement + Linet top Packer.

14a. The 5-1/2"x 9-5/8" liner top packer will be rated for a minimum of 5000 psi pressure differential.

14b. There are no well bore fluid change- out planned for this well. Therefore, no negative tests are planned for this well. If a production liner is to be run and a completion fluid used, a negative test will be presented in a subsequent Application for Completion Permit.

15. This is a surface wellhead, therefore no casing hanger lockdown mechanisms planned.