Attachment 1

Request for Additional Information for the Application for Construction Permit AQ0069CPT02, Grayling Platform Responses Specific to Application Attachment C – SO_2 Best Available Control Technology

Below are responses to the Alaska Department of Environmental Conservation's (ADEC) request for additional information to complete processing of the application for Construction Permit AQ0069CPT02 specific to Attachment C of the application (SO_2 Best Available Control Technology (BACT)).

Request 1:

In accordance with 40 CFR 52.21(j)(3), BACT will be applied to each emissions unit at which a net emissions increase in SO_2 would occur as a result of the increase in the H_2S limit for fuel gas. Therefore, BACT will clearly apply to EUs 1, 3, 4a, 14 through 18, 28, 29, and 31 listed in Operating Permit AQ0069TVP04. Our records indicate BACT will also apply to EUs 19a, 19b, and 20a (glycol water heaters). The emissions calculations in the construction permit application also show two other gas fired units as part of the insignificant emissions unit inventory (Clayton ROG-60-1 Boiler and Clayton Sigma Fire). BACT will also apply to these units, and they should be given emissions unit IDs so they can be included in the construction permit. Please provide a complete list of emissions units subject to BACT with emissions unit IDs.

Response: The proposed and requested fuel gas H_2S content BACT limit of 650 ppm applies to each existing gas-fired emissions unit that operates on the Grayling Platform and the SO_2 emissions management / control we proposed as BACT in the construction permit application is "good combustion practices," which essentially is compliance with ADEC's Standard Permit Condition VI "Good Air Pollution Control Practices" provision in 18 AAC 50.346(b)(5). While this provision technically does not apply to insignificant emissions units (IEUs), we believe this provision provides the best method of describing what is required to manage emissions according to "good combustion practices," including IEUs on the platform. This is acceptable to Hilcorp in this context.

Therefore, the list of emissions units subject to BACT under this application is as follows:

EU ID	Emissions Unit Name	Fuel	Rating/Size
1	Solar Centaur T4500	Fuel Gas	4,500 hp
3	Solar Centaur T4500	Fuel Gas	4,500 hp
4a	Solar Centaur T4500	Fuel Gas	4,500 hp
14	Solar Saturn T1200	Fuel Gas	1,100 hp
15	Solar Saturn T1200	Fuel Gas	800 kW
16	Solar Saturn T1200	Fuel Gas	750 kW

EU ID	Emissions Unit Name	Fuel	Rating/Size
17	Solar Saturn T1200	Fuel Gas	800 kW
18	Solar Saturn T1200	Fuel Gas	800 kW
19a	Riello AR 400 Boiler	Fuel Gas	4 MMBtu/hr
19b	Riello AR 400 Boiler	Fuel Gas	4 MMBtu/hr
20a	Riello AR 400 Boiler	Fuel Gas	4 MMBtu/hr
28	Flare (South)	Fuel Gas	0.12 MMscf/day, pilot/purge combined
29	Flare (SW)	Fuel Gas	14 MMscf/day, emergency each
31	Solar Taurus 60 T-7300S	Fuel Gas	5.2 MW
32	Clayton ROG-60-1 Boiler	Fuel Gas	2.5 MMBtu/hr
33	Clayton Sigma Fire Boiler	Fuel Gas	50 bhp

Request 2:

The RACT/BACT/LAER Clearinghouse (RBLC) identifies the use of low sulfur fuel gas as a control method for BACT for SO_2 in many circumstances for gas-fired units and low sulfur fuel gas from the Steelhead Platform is already used in the comingled fuel for the Grayling Platform. The proposed BACT limit of 650 ppm H_2S is based on using the maximum amount of sour produced gas the platform can provide and the sweet gas added from the Steelhead Platform. However, use of the low sulfur fuel in place of the high sulfur produced gas is not identified as an available control option in the BACT analysis in the construction permit application. Please revise the construction permit application to include the use of low sulfur fuel gas as a control option for SO_2 BACT. In the analysis for this control option, the feasibility of using only sweet gas from the Steelhead Platform should be addressed and a cost analysis provided if the control method is feasible.

Response: The RBLC identifies the use of low-sulfur fuel as a control method for those subject projects because those projects utilize pipeline quality natural gas, or gas that is otherwise inherently low in sulfur. Hilcorp did not include the option to use low sulfur fuel imported from shore or another platform because it is technically infeasible. The sour gas produced by the platform must be either burned locally or controls added. The BACT analysis provided in the application addresses the other control options.

Request 3:

In Section C3.3.2.4 of Attachment C to the construction permit application, the Adsorption Process (Amine Treatment) control option is listed as technically infeasible because an additional treatment system for the sour gas stream would not be cost effective. In Step 2 of the top down BACT analysis process, control options are eliminated if they are technically infeasible due to physical, chemical, and engineering difficulties. Costs are not a consideration in Step 2. Please revise the reason provided for why the Adsorption Process is not feasible or include the Adsorption Process in Steps 3 through 5.

Response: Section C3.3.2.4 of Attachment C to the construction permit application mis-identified amine treatment as a chemical solvent-based “adsorption” process, when in fact it is an “absorption” process. Chemical absorption processes for removing sulfur from a natural gas stream use alkanolamine compounds, most commonly use monoethanolamine (MEA), diethanolamine (DEA), and methyldiethanolamine (MDEA) (hereafter “amine”). The inlet gas containing hydrogen sulfide (H_2S) (“sour gas”) is routed to an absorber tower where the gas counter-currently contacts a “lean” amine solution, which absorbs acid gases, H_2S and carbon dioxide (CO_2). Treated “sweet gas” exits the top of the absorber tower and liquid “rich” amine solution exits the bottom of the contactor from which it is routed to a regeneration process. The regeneration or “regen” process is composed of a stripper tower and reboiler. The rich amine is heated and stripped to remove acid gases, after which the “lean” amine is recycled back to the absorber in a continuous cycle. The acid gas discharged from the regen process contains concentrated H_2S, CO_2, and other impurities including hydrocarbons and some amine solution.

As noted in Section C3.3.2.4 of Attachment C to the construction permit application, the amine treatment process is not in and of itself a control option. The sweet gas product may be used as fuel gas in fuel burning equipment, reducing SO_2 emissions from those sources, but the acid gas containing H_2S must either be flared or otherwise oxidized (forming SO_2), or routed to a sulfur recovery unit (SRU), such as a Claus SRU, to remove elemental sulfur. The tail gas from the Claus SRU also contains unconverted H_2S, SO_2, and carbonyl sulfide (COS), which must be burned. The heating value of the acid gas stream is low, so the gas must be supplemented with natural gas before combustion in a flare. Alternatively, the acid gas stream may be burned in a thermal oxidizer fired on natural gas.

The amine sweetening unit would include the following major equipment: Amine storage tank, vertical absorber tower, various vessels and drums, heat exchangers, pump(s), natural gas-fired reboiler, regenerator (stripping tower), thermal oxidizer (if needed), piping and equipment. A Claus SRU would additionally include: a Claus furnace (fuel gas fired), Claus reactor vessels, heat exchangers, coolers, molten sulfur tank(s), solid sulfur storage, handling and transport equipment.

The amine sweetening process is technically infeasible. The footprint and vertical space and weight requirements of the amine treating process in and of itself precludes consideration for installation on the 1960s era platform. Setting the high space and weight requirements of the amine process aside, the acid gas would either have to be burned on the platform, resulting in SO_2 emissions (zero net control), or the acid gas stream would have to be captured, compressed and routed via underwater pipeline to an onshore sweetening unit, which would also emit SO_2. In addition, an SRU is suitable for removing sulfur from acid gas streams with high (i.e., percent level) H_2S concentrations and high flow rates, which do not apply to operations that would exist at the Grayling Platform. As shown in Figure C3-1 “Sulfur Removal Technologies,” in Attachment C of the application, the required H_2S concentration and gas rate that would make the potential use of an SRU (i.e., identified as “Amine/Clause” in the figure) worth further consideration for this project is much higher than exists or will exist at the Grayling Platform. Therefore, we did not consider this control technology further when developing the construction permit application.

<u>Request 4:</u>

In the Direct Costs section of Table C2-1: Grayling Platform Capital Cost Factors in the construction permit application, the factors for platform construction costs are multiplied by the Basic Equipment and Auxiliaries Cost rather than the Total Purchased Equipment Cost as is shown in the EPA Air Pollution Control Cost Manual. Please <u>provide an explanation for these calculations</u>. If this was simply an error in the calculations, the Department will revise these costs in accordance with [the] Air Pollution Control Cost Manual and note the change in the technical analysis report.

Response: Hilcorp does not typically consider shipping costs and taxes as having an impact on construction costs; however, to be consistent with our use of the EPA Cost Control Manual for construction costs we agree that the total equipment costs should be included in the calculation. We invite the Department to revise the costs as offered at the conclusion of Request 4.

Request 5:

In the Indirect Costs section of Table C2-1: Grayling Platform Capital Cost Factors in the construction permit application, the Engineering and Procurement, Unit Operator Costs (UOC), and Start-up calculations are based on methods from Worley Parsons. Please provide an explanation of why those methods are used rather than those shown in the Air Pollution Control Cost Manual.

Response: Hilcorp used methods from Worley Parsons due to their extensive experience with design, procurement, and construction at remote locations such as the Cook Inlet.