HYDROGEN ENERGY CALIFORNIA

RESPONSES TO NOTICE OF INCOMPLETE APPLICATION

PROJECT NUMBER: S-1093741

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Prepared for:

San Joaquin Valley Air Pollution Control District

Prepared on behalf of:

Hydrogen Energy International LLC

June 23, 2009

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Hydrogen Energy California
Responses to Notice of Incomplete Application
SJVAPCD Project Number: S-1093741

DISTRICT QUESTIONS 1 AND 2

Combustion turbine generator (CTG):

1. Explain why the proposed natural gas firing emission factors for the CTG do not meet the Best Available Control Technology (BACT) requirements of BACT guidelines 3.4.2 for gas turbines.

2. Provide documentation from the manufacturer of the selective catalytic reduction (SCR) system indicating that the SCR will properly operate and comply with the proposed emission limits when firing on the proposed fuels.

APPLICANT'S RESPONSES

Response to 1:

The combustion turbine generator (CTG) will be required to burn both hydrogen-rich fuel and natural gas. The Dry Low NOx™ (DLN) burner technology capable of meeting the BACT emission limits of the BACT guidelines 3.4.2 for gas turbines is not offered by GE for this application because of the dual fuel requirements. A diffusion type burner technology is all that is available. With a diffusion burner General Electric (GE) guarantees NOx emissions at 25 parts per million (ppm) when firing natural gas rather than the 9 ppm from a DLN burner. Subsequent control of NOx in the SCR will reduce this to the 4 ppm BACT level proposed. This is explained in more detail in the discussion in the ATC Application, BACT Appendix D2, specifically page D2-11.

Response to 2:

When firing natural gas, the SCR will reduce NOx concentrations from 25 ppm at the SCR inlet to 4 ppm or less at the SCR outlet. This equals a NOx removal efficiency of 84 percent. Table 2-1 from Cormetech, the principal manufacturer of SCR catalyst, lists their SCR field performance information for selected recent projects. As shown, SCR NOx removal efficiency performance is greater than that required for the HECA project. Most of the experience is for natural gas operation, with one refinery fuel gas case. Cormetech states that the fuel type is of secondary importance. SCR performance is primarily dependent on the inlet temperature, flue gas composition, NOx level and the NH_3 slip. Flue gas constituents free oxygen (O_2) and water (H_2O) have an influence on SCR performance. Increasing the O_2 content enhances SCR performance while increasing H_2O content reduces it. For the ranges of flue gas compositions expected for the HECA Project, the catalyst system can be designed to meet the proposed NOx emission limits. Contaminants are also a concern, primarily metals and sulfur compounds, neither of which exist in high enough quantities in the HECA proposed fuels to be a problem. SCR for NOx removal has not been demonstrated for any IGCC in the US. Also noteworthy is that the NPRC Negishi refinery in Japan has proven commercial operation of an SCR in a power plant application using syngas derived from residual oil but not petcoke or coal feedstock.

Table 2-1
Selected Cormetech SCR Field Experience

Plant #	Delivery Year	State	Fuel Type	Inlet NOx ppmc*	NOx Removal Efficiency %	Outlet NOx ppmc	Slip ppmc	Unit Type
1	2000	MA	NG	25.0	92.0	2	2	CTG
3	2001	MA	NG	50.0	96.0	2	2	CTG
7	2003	CA	NG	27.2	92.7	2	5	CTG
9	2004	CA	Ref. Gas	41.7	95.2	2	5	CTG
12	2007	CA	NG	41.7	95.2	2	5	CTG

Source: Cormetech Inc., Experience tables dated August 2008.

* ppmc denotes parts per million by volume, dry, corrected to 15% O2

DISTRICT QUESTIONS 3 AND 4

Combustion turbine generator (CTG) and Auxiliary CTG:

3. Provide justification for longer start-up duration as required by Rule 4703 Section 5.3.3.

4. Provide documentation for the proposed emission limits.

APPLICANT'S RESPONSES

Response to 3:

The gas turbine start up duration is defined ~~as the time from fuel ignition until the emissions are in compliance with the normal operating emissions~~. This time was specified as up to 180 minutes for the cold start of the CTG and up to ten minutes for the start of the Auxiliary CTG. SJVAPCD Rule 4703 sets a goal of two hours for startup but allows longer times if justified by the Applicant. Therefore, the startup time for the Aux CTG complies with Rule 4703. The justification for the longer time required for the CTG is provided here.

A cold start of the 7FB combined cycle power block could require a period of up to three hours (from ignition to emissions compliance). The rationale for this duration are (1) the limited experience with Integrated Gasification Combined-Cycle (IGCC)-derived hydrogen fuels, (2) the significant differences between the diffusion combustor system for hydrogen-rich fuel and the more common dry low NOx (DLN) combustor for the typical natural gas combined cycle (NGCC) plant, (3) other design differences to accommodate the IGCC operation, and (4) to preserve the opportunity to select different suppliers for the CTG, steam turbine generator (STG), and heat recovery steam generator (HRSG). The primary differences in this IGCC plant compared to the typical DLN/NGCC facility are described below:

- The 7FB utilizes a diffusion flame combustion system for IGCC fuels, requiring significant amounts of steam injection during startup to control NOx unlike the DLN combustion system for non-hydrogen fuels.

- The HRSG utilizes a non-typical, more complex heat transfer surface area distribution to accommodate the heat integration with the gasification process block in order to recover the available energy.

- A non-standard/non-structured STG design is necessary to accommodate the high levels of low pressure steam admission resulting from the process heat integration. This STG will have a rotor design differing substantially from the structured STG typical of NGCC applications. This STG has not yet been designed, resulting in more uncertainty than present in today's NGCC plants.

- With the 7FB operating in emission compliance, the steam injection requirements are substantial. Providing for this steam while maintaining control of the steam flow and temperature entering the STG is significantly more complex than that for a NGCC plant which does not require steam injection. Operating the 7FB at part load for a longer period of time during a cold start partially alleviates the demand placed on the system by steam injection.

Response to 4:

Attachments 4-1 and 4-2 present the supplier's estimated performance and emissions information for the combined cycle (7FB) and auxiliary (LMS100) CTGs, respectively.

DISTRICT QUESTIONS 5, 6, AND 7

Engines:

5. Identify the manufacturer and model, provide specifications and emission limits specific to the engines.

6. Indicate if the emergency engines powering the electrical generators will be equipped with a positive crankcase ventilation system as required by BACT Guidelines 3.1.3.

7. For the engine driving the fire water pump, provide cost data for the installation and operation of a catalytic oxidation system to enable the District to determine whether this technologically feasible control identified in BACT Guideline 3.1.4. is cost effective.

APPLICANT'S RESPONSES

Response to 5:

Cummins Model No. DQKC Diesel Engine Generator Set is typical of the type that will be used for emergency power. Cummins Model No. CFP5E-F30 Fire Pump Driver is typical of the type that will be used for the fire water pump engine. The Cummins DQKC and CFP5E data sheets are presented in Attachments 5-1 and 5-2, respectively.

Response to 6:

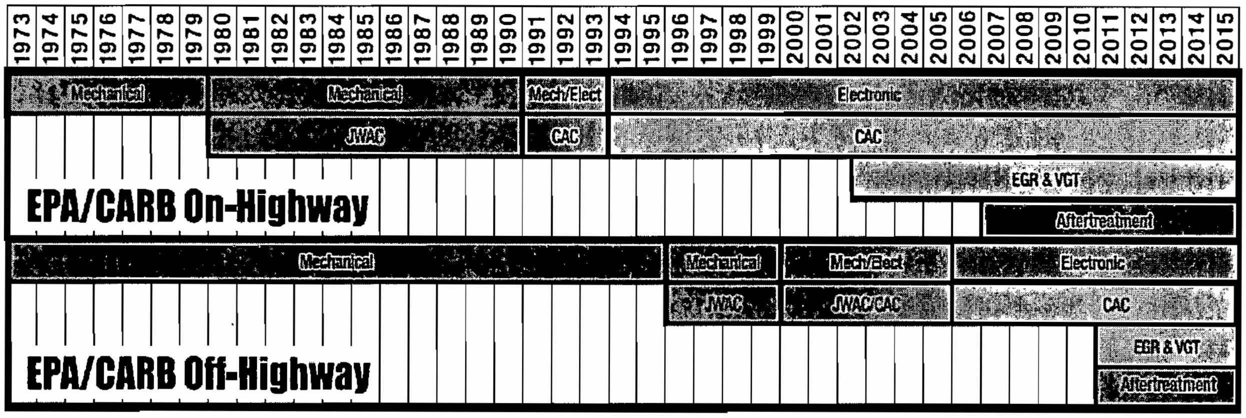
Cummins (or an equivalent supplier) will provide engines compliant with the U.S. Environmental Protection Agency (U.S. EPA) tier rules applicable to the year that they ship. They will be equipped with a positive crankcase ventilation system.

Response to 7:

Cummins (or an equivalent supplier) will supply the fire water pump engines compliant with U.S. EPA tier rules applicable to the year they ship. The current schedule indicates that a catalytic oxidation system (aftertreatment) will be required to meet the emission rules beginning in year 2011. Therefore, the price of the aftertreatment equipment will be included in the purchase price and separate pricing will not be quoted. Refer to Table 7-1 below for what Cummins states they will be shipping for off-highway applications beginning in year 2011.

Table 7-1

Emissions Technology – Cummins MidRange and Heavy-Duty Diesel Engines



- Fuel System/Controls (mechanical to electronic)
- Charge Air Temperature Control (jacket-water aftercooled [JWAC] to air-to-air aftercooled [CAC])
- EGR (cooled Exhaust Gas Recirculation) and VGT (Variable Geometry Turbocharging)
- Exhaust Aftertreatment

DISTRICT QUESTIONS 8 AND 9

Auxiliary boiler:

8. Identify the manufacture and model, provide specifications, and provide documentation of emission factors.

9. Provide justification for longer start-up duration as required by Rule 4306 Section 5.3.3.

APPLICANT'S RESPONSE TO 8 AND 9

Response to 8:

Attachment 8 provides manufacturer specifications and emission rates for a typical example of this equipment based on Fluor experience for a recent project. This data sheet shows the emission factors used to estimate auxiliary boiler emissions of VOC and PM10 for the HECA Project. The SO_2 emissions are based on the sulfur specification for natural gas. The NOx limit of 9 ppm (0.011 lb/mmBTU) is a regulatory requirement in Rule 4306. The Taylorville project discussed in detail in the ATC Application, BACT Appendix D2, contains a permit limit on the emissions of CO from the auxiliary boiler for that project. The limit is 50 ppmvd at 3% O_2 (0.037 lb/mmBTU). This is using a low NOx burner, good combustion practices, and uses a 24-hr block average. However, the low NOx burner at Taylorville was required to meet a NOx limit of 30 ppm. Discussions with equipment suppliers will continue to determine if the requirement to meet 9 ppm NOx will necessitate a CO limit higher than 50 ppm.

Response to 9:

The startup up time for the auxiliary boiler is limited by Rule 4306 Section 5.3.1 to not exceed two hours. The auxiliary boiler will comply with this requirement; therefore, no justification of a longer time is necessary. The Supplemental Data Form for the auxiliary boiler in Appendix B should have indicated 2,190 hours/yr of steady state operation rather than start-up.

DISTRICT QUESTION 10

Thermal oxidizer:

10. For the thermal oxidizer serving the sulfur recovery system, identify the manufacturer and model, provide specifications and documentation of emission factors.

APPLICANT'S RESPONSE TO 10

The thermal oxidizer and the sulfur recovery system are custom systems and design details are not final. However, the emissions performance stated in the application will be met.

The Tail Gas Thermal Oxidizer (TGTO) supplier has not been selected. For purposes of the Revised AFC it was assumed that this equipment would be similar to a SRU Tail Gas Thermal Oxidizer provided by Callidus for another recent Fluor project. The NOx and CO emission factors for the Revised AFC were taken from this similar unit. SO_2 emissions were estimated from an assumed sulfur content in the combusted waste gases. However, the TGTO for HECA will be designed to treat sulfur containing gases expected to be much lower in sulfur than the TGTO treats in a typical refinery.

PM_{10} and VOC emission factors for natural gas combustion were taken from U.S. EPA AP-42, Table 1.4-2.

DISTRICT QUESTIONS 11 AND 12

Refractory heaters:

11. Identify the manufacturer and model, provide specifications and documentation of emission factors.

12. For your proposed use of an alternative monitoring procedure other one already pre-approved please provide a technical justification and demonstrate that the parameters to be monitored have a strong correlation with NO_x and CO emissions and will provide a reasonable assurance of compliance per Rule 4306 Section 5.4.

APPLICANT'S RESPONSES

Response to 11:

The Gasifier Refractory Heater parameters and performance have not yet been specified nor has a supplier been selected. For the Revised AFC it was assumed that emissions from this natural gas-fueled equipment would be similar to the natural gas emission factors for small boilers (<100 million Btu/hr) shown in AP-42 Table 1.4-1. These factors were used to calculate the Refractory Heater emissions. Because of the uncertainty in the eventual equipment specification a margin of 10 percent was added to the NOx and CO factors.

Subsequent to the Revised AFC submittal, a potential supplier (John Zink Co.) has been identified and requested to verify and/or update the original emission assumptions. Updated equipment specifications and emission information will be provided when available.

Response to 12:

No justification for alternative monitoring is required because Rule 4306 does not apply to the refractory heaters. The refractory heaters do not produce any hot water, steam, or transfer the heat from combustion gases to water or process streams and therefore do not fall into the types of equipment regulated by Rule 4306 Boilers, Steam Generators, and Process Heaters – Phase 3. The refractory heaters act like the heaters used to preheat kilns or ovens. Kiln and oven heaters are specifically exempt per Rule 4306 Section 3.15.

However, as stated in the Applications Forms in the ATC Application, Appendix B, the refractory heaters will consume less than 30 Billion BTU/yr each of fuel, which will be verified by a fuel use meter.

DISTRICT QUESTION 13

Flares:

13. Identify the manufacturer and model, provide specifications, and provide documentation of emission factors. Also provide details of the flare design and emission control equipment.

APPLICANT'S RESPONSE TO 13

As previously explained, the suppliers for each of the three flares included in the project have not yet been selected. Preliminary information was provided by several well-established flare system suppliers, including Callidus Technologies, John Zink Company, and Flaregas Corporation. Attachments 13-1 and 13-2 show the information provided as typical for this equipment by Callidus. The emission factors from the Callidus package are generally used for the emission calculations presented in the Revised AFC, with a couple of exceptions where somewhat larger emission values were used in order to maintain Hydrogen Energy International LLC's flexibility for supplier selection.

Flaring emissions are controlled by essentially limiting flaring events to startup operations and upset/emergency conditions. No sulfur-containing streams will be flared during planned startup activities. Gasifiers will be started up on very low sulfur fuels. As described in the Revised AFC, a dedicated caustic scrubber will be installed to prevent the flaring of relatively high sulfur streams during SRU startups and relatively short Acid Gas Removal (AGR) Unit upsets. A small amine contactor will also be provided for desulfurization of raw syngas (upstream of the AGR) prior to depressuring to the Gasification Flare during plant shutdowns. This system is also described in the Revised AFC.

DISTRICT QUESTION 14

CO_2 Vent:

14. Indicate the maximum daily and annual vent throughput rates. Identify the composition of the gas to be vented.

APPLICANT'S RESPONSE TO 14

The carbon dioxide (CO_2) vent will operate only during startup and as an alternative operating scenario when CO_2 injection capability is not available. The maximum duration of CO_2 venting within a year is 504 hours. The maximum vent rate is 656,000 lbs/hour. This rate could occur up to 24 hours per day. The resulting maximum daily emission would be 15,744,000 pounds. The composition of the CO_2 vent stream is anticipated to be almost entirely CO_2 with up to 1,000 ppm CO, 40 ppm VOC, and up to 65 ppm total reduced sulfur compounds including 10 ppm hydrogen sulfide (H2S) and up to 55 ppm carbonyl sulfide (COS). This information is provided in the ATC Application, Appendix D1.2, page 45 of 57 and Table 8-11.

DISTRICT QUESTION 15

Baghouses:

15. Identify the manufacturer and model and provide specifications of the baghouses serving the feedstock handling system.

APPLICANT'S RESPONSE TO 15

The baghouse equipment manufacturer has not yet been identified. However, the equipment to be provided will be required to meet an outlet grain loading not to exceed 0.005 grains of particulate per standard cubic foot of air for each of the six baghouses proposed. This information is provided in ATC Application, Appendix D1.2, page 47 of 57.

DISTRICT QUESTION 16

General:

16. Indicate the distance and direction from the emissions units in this project to the nearest sensitive receptor (residence, school, etc.) and the nearest business.

APPLICANT'S RESPONSE TO 16

The approximate distances between the Project Site and residences, schools, businesses or other receptors of interest by type is provided in Table 16-1. The distances provided are measured from the Project Site where all proposed emissions units are located. The Controlled Area is excluded because no emissions units are located in the Controlled Area.

Table 16-1
Distances to Residences, Schools, Businesses and Other Receptors of Interest

Place/Receptor	Location	Direction from Project Site	Distance from Project Site (Excluding Controlled Area)
Residence	7345 Adohr Road Buttonwillow	North	370 feet
Residence	8229 Station Road Buttonwillow	East	1,400 feet
Residence	6122 Tule Park Road Buttonwillow	East	1,500 feet
Tule Elk State Natural Reserve (Park and Visitor Center)	8653 Station Road Buttonwillow	East	1,700 feet from western edge of reserve; 3,600 feet from Visitor Center
Residence	Tupman Road, Buttonwillow	Southeast	3,300 feet
Residence	7765 Stockdale Highway Buttonwillow	North	4,000 feet
Elk Hills Oil Field Unit	N/A	South	1 mile
Kern Water Bank	N/A	East	1 mile
Elk Hills Elementary School	501 Kern Street, Tupman	Southeast	2.3 miles
Oasis Church of God	405 Kern Street, Tupman	Southeast	2.5 miles
Tupman (unincorporated community)	N/A	Southeast	1.5 miles from edge of community
Buttonwillow (unincorporated community)	N/A	Northwest	4 miles
Buttonwillow Elementary School	42600 Highway 58 Buttonwillow	Northwest	6.2 miles
City of Bakersfield	N/A	East	6.6 miles

Table 16-1 (Continued)

Distances to Residences, Schools, Businesses and Other Receptors of Interest

Dykstra Dairy Farm (Proposed Business: environmental review underway by Kern County. Project not yet constructed)	Southwest corner of Adohr Road and Dairy Road; Directly across the Dairy Road right-of-way from Project Site	West	Adjacent
Agricultural properties adjacent to Project Site	Various	North, East, West	Adjacent
Stockdale Ranch	32900 Stockdale Highway	Northeast	1 mile
Tupman Post Office	337 Emmons Blvd	Southeast	2.5 miles
Gas Station and Food Establishments	Various on east side of Highway 5 at Stockdale Highway	Northeast	2.5 miles