ENVIRON

June 8, 2011
Project No. 29-23586A

Mr. Gerardo Rios
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, California 94105

Subject: Response to Additional Information Request
Sierra Pacific Industries Biomass-Fired Cogeneration Project
Anderson, California

Dear Mr. Rios:

This letter provides information requested by the U.S. Environmental Protection Agency, Region 9 (Region 9) during a conference call with Sierra Pacific Industries (SPI) on January 11, 2011 to discuss the cogeneration project proposed by SPI. The information requests are provided as italicized introductions to each response.

Provide greenhouse gas (GHG) emission rates associated with the project.

The proposed cogeneration unit will be designed to have an annual average heat input of 425 million British thermal units per hour (MMBtu/hr). GHG emission factors for CO_2, methane (CH_4), and nitrous oxide (N_2O) were obtained from Tables C-1 and C-2 of the Federal Mandatory GHG Reporting Rule (40 CFR Part 98). Table 1 summarizes the calculations and shows that the proposed unit has the potential to generate a maximum of approximately 393,000 tons of CO_2e per year. The proposed unit combusts a small amount of natural gas during a limited number of startup events throughout the year, but the vast majority of emissions will be from combustion of solid biomass fuel.

Table 1. Greenhouse Gas Energy Output Emission Factor Calculations

Pollutant	Emission Factor (Heat Input)[1]		Global Warming Potential[2]	Emission Rate[3]	
	(kg/MMBtu)	(lb/MMBtu)		(lb/hr)	(tpy)
CO_2	93.8	207	1	87,973	385,322
CH_4	3.20E-02	0.0705	21	30.0	131
N_2O	4.20E-03	0.00926	310	3.94	17
CO_2e	--	--	--	89,824	393,431

1 The kg/MMBtu emission factors for combustion of wood and wood residual solid biomass fuel are from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu emission factors are calculated by converting the kg/MMBtu emission factors using 2.2046 lb/kg.
2 100-year time horizon global warming potential (GWP – from 40 CFR Part 98, Table A-1.
3 Calculated by multiplying the emission factor by the annual average heat input (425.419 MMBtu/hr). CO_2e was calculated by multiplying each individual emission rate by the applicable GWP factor, and summing.

Provide a Best Available Control Technology (BACT) analysis for GHG emissions associated with the proposed project.

Please find a GHG BACT analysis attached to this letter.

Justify the exclusion of circulating fluidized bed (CFB) boiler designs from Step 1 of the BACT analysis provided in support of the submitted permit application.

The Anderson lumber manufacturing facility produces more biomass fuel than the existing boiler can combust. Rather than continuing to sell the excess fuel, SPI proposes to install a larger cogeneration unit capable of combusting most, if not all (depending upon economic conditions), of the fuel generated on site. The steam produced by the proposed cogeneration unit would not only heat the lumber drying kilns at the facility, but produce enough electricity to power the facility while delivering approximately 24 MW of renewable energy to the grid.

In 2009, the Environmental Review Board (ERB) remanded a permit issued to a proposed coal-fired power plant in New Mexico (Desert Rock Energy Co.), stating that Region 9 "abused its discretion in declining to consider integrated gasification combined cycle (IGCC) as a potential control technology in Step 1 of its BACT analysis for the facility." In light of that ruling, Region 9 has requested that SPI retroactively include CFB boiler designs in the submitted analysis, or justify the exclusion of CFB designs from Step 1 of the BACT analysis.

The BACT analysis provided as an appendix to the permit application stated that fluidized bed boiler technology was not considered for the proposed project. Whereas SPI has considerable institutional experience operating biomass-fired boilers, it has no experience with fluidized-bed designs. Were a fluidized-bed boiler selected for the project, extensive training or replacement of existing personnel at the facility would be required to address the significant operational differences between the two design technologies.

Additionally, SPI is aware of the experience of the 25-MW Rio Bravo Rocklin Power Station in Lincoln, California, which recently spent $14 million to improve availability of a biomass-fire CFB boiler from 77 percent to 88 percent. In comparison, the proposed boiler is expected to have an availability of greater than 90. The business viability of the Anderson facility depends upon a near-constant supply of steam to heat the lumber dry kilns, and, based on the experience of the nearest CFB boiler combusting similar fuel, a CFB design would not provide the long-term reliability SPI requires.

While not explicitly stated in the permit application or BACT analysis, SPI's desire to incorporate a new, reliable boiler into the existing Anderson facility with minimal alteration to operations and personnel was one of the chief reasons for not considering CFB designs. SPI believed then, as now, that consideration of a CFB design would constitute a redefinition of the project.

Fluidized-bed units differ from most other biomass-fired boiler designs in that the fuel is introduced into a suspended bed of sand-like material instead of onto a grate or floor. The bed material "scours" the char from fuel particles, allowing oxygen in the combustion air to access un-combusted fuel. Notable operational differences between fluidized-bed and other biomass-fired boiler designs include:

- higher parasitic load (additional power needed to operate the fan that suspends and circulates the bed materials),
- shorter boiler life (increased metal erosion due to circulating bed material),and
- generally more complex operation (the bed must be "tuned" to accommodate changing fuel characteristics, and fuel must be sized appropriately) and logistics (management and maintenance of the bed material).

In its Desert Rock ruling, the EAB seeks to provide a redesign test by answering the question: "when does the imposition of control technology require enough of a redesign of the proposed facility that it strays over the dividing line to become an impermissible redefinition of the source?" Referring to a previous ruling (Prairie State) the EAB's response to the question is: "the permit applicant initially 'defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design,' although the applicant's definition must be 'for reasons independent of air permitting.'" Not anticipating Region 9's request, the permit application did not include an explicit statement of the proposed project's end/object/aim/purpose in terms that would directly address the EAB's design test. Nevertheless, from the outset of the project, the end/object/aim/purpose has been to generate more steam and more fully utilize the biomass fuel generated on-site, while minimizing changes to the existing facility.

In the Desert Rock ruling, the EAB explains how the permit issuer should conduct the proper test for redesign:

> *"... take a 'hard look' at the application determination in order to discern which design elements are inherent for the applicant's purpose and which design elements 'may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility,' while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility."*

Applying this "hard look" to the proposed project, substitution of a CFB design for the proposed boiler would disrupt the basic business purpose of the project, which is to increase the biomass fuel combustion and steam generation capacity, while minimizing changes to the existing facility. In the simplistic view, a CFB boiler would combust biomass fuel and produce steam, and is therefore interchangeable with any other boiler with similar inputs and outputs. In reality, insertion of a CFB boiler into the proposed project would affect certain operations and personnel at the facility to an extent that is difficult to quantify.

In addition to the redesign test outlined above, there are important differences between the Desert Rock project and SPI's proposed project that relate to the arguments presented in the EAB's ruling in that case. First, the EAB points out that, in its 2004 application, the Desert Rock project permit application included IGCC technology as one of four technologies under consideration. In contrast, SPI stated, not only in the permit application submitted in March 2010, but also in the permit application submitted in May 2007 for a smaller, previously proposed project, that fluidized bed technology was not under consideration.

The second factor cited by the EAB in the Desert Rock ruling was that two permits for similar sources (Christian County and Prairie State) issued by Illinois Environmental Protection Agency (IEPA) under delegation of authority from EPA Region 5 both considered IGCC in Step 1 of the BACT analysis, and the Desert Rock permit application contained no explanation as to why IGCC should not be considered in Step 1. It is true that, as with Desert Rock, SPI's permit application does not contain an explanation as to why fluidized bed boiler designs were not under consideration (at the time, the boiler design had not been finalized, but it was implied that fluidized bed designs were not under consideration). On this point, the difference between Desert Rock and the SPI project lies in the fact that other biomass-fired boiler permit applications also do not address alternative boiler designs in Step 1 of the BACT analysis. As a recent example, a major source permit was issued on March 28, 2011 by the Wisconsin Department of Natural Resources under delegation authority from EPA Region 5 to We Energies for a new facility in Rothschild, Wisconsin. In Step 1 of the BACT analysis submitted in support of the permit application, no alternative boiler designs were considered. Furthermore, when commenting on the proposed permit in a letter dated March 4, 2011, Region 5 raised several issues concerning the BACT analysis, but none of them included a request that other boiler designs be considered in Step 1 of the BACT analysis.

In summary, the EAB ruled (in Desert Rock) that Region 9 "abused its discretion" by not considering an alternative source design. To avoid the potential for a similar ruling regarding SPI's proposed project, Region 9 requested that SPI include an alternative boiler design (i.e., CFB) in the BACT analysis. The Desert Rock EAB ruling was based on two findings: (1) that the original statement of the project goals included the alternative source design in question as a possible approach, and (2) recently submitted permit application for similar proposed sources had considered the alternative source design in question. The project proposed by SPI differs from Desert Rock on both counts: (1) a CFB design was never under consideration for the proposed project, and (2) recently proposed biomass-fired boilers have not considered alternative boiler designs. In light of these differences, SPI proposes that retroactive consideration of CFB boiler design for the proposed project would constitute redefinition of the source, and Region 9 would not be abusing its discretion by allowing CFB boiler designs to be excluded from Step 1 of the BACT analysis.

Provide more detailed information regarding BACT during startup and shutdown periods, as well as proposed emission limits for startup and shutdown.

As stated in the September 7, 2010 letter responding to Region 9's second incompleteness determination, SPI will limit the frequency and duration of startup and shutdown periods through the implementation of the manufacturer's recommended procedures and operator training. However, because the final boiler design is better defined than it was at that time, additional details regarding the startup process can be provided.

The boiler startup process begins by igniting a pile of biomass fuel on the grate and firing the 2 (two) 62.5 MMBtu/hr natural gas burners located near the steam tubes. Once the biomass fuel is burning, the fuel feed system will be activated at a low feed rate. After approximately 12 hours, the boiler will be at about 50 percent of full load, at which point the selective non-catalytic reduction (SNCR) system, used to reduce oxides of nitrogen (NO_X) in the exhaust, and the electrostatic precipitator (ESP), used to control particulate matter (PM) emissions, can be activated. From this point on, the boiler will meet the normal operation emission rates presented in the permit application.

The boiler manufacturer does not have emissions data for the startup period. Emissions of NO_X and SO_2 during startup are expected to be less than during normal operation as a result of reduced furnace temperatures and fueling rate. Emissions of CO, VOC, and PM are expected to be mitigated to some extent by simultaneous operation of the natural gas burners. However, the relative influences of the various competing factors are difficult to assess without concentration data obtained during startup.

Ideally, permit limits for startup and shutdown periods will be both operationally feasible and protective of the national ambient air quality standards (NAAQS). The ambient impacts predicted by the air quality dispersion modeling results developed for the PSD permit application and in response to Region 9 information requests were used to determine whether the increased emission rates expected during startup or shutdown will comply with the NAAQS. Based on this analysis, SPI proposes the following hourly emission limits for startup and shutdown periods:

Pollutant	Proposed Startup/Shutdown Emission Rate (lb/hr)	Averaging Period	Basis
NO_X	94.3	1-Hour	55% greater than normal operation emission rate; NAAQS compliance demonstration discussed in Sep. 7, 2010 letter
CO	400	1-Hour	NAAQS compliance demonstration for this emission rate discussed in March 2010 permit application
PM/ PM_{10}/ $PM_{2.5}$	18.7	24-Hour	Twice normal operation emission rate; scaling predicted ambient impacts is less than the applicable PM_{10} SIL, and in compliance with $PM_{2.5}$ NAAQS; see March 2010 permit application
SO_2	4.68	1-Hour	Twice normal operation emission rate; scaling predicted ambient impact of project is less than the applicable SO_2 SILs; see March 2010 permit application

What emission limits does SPI propose be included in the permit, and what averaging periods should be associated with those limits?

SPI proposes the following permit limits and averaging periods:

Pollutant	Emission Limit (lb/MMBtu)	Averaging Period	Basis
NO_X	0.15	3-Hour	Protective of NAAQS; accounts for fuel variability
	0.13	Annual	Protective of NAAQS; reflects BACT
CO	0.35	3-Hour	Protective of NAAQS; reflects BACT; complies with MACT limit for new Dutch Oven-type boilers
$PM/PM_{10}/PM_{2.5}$	0.0011	3-Hour	Protective of NAAQS; reflects BACT; complies with MACT limit for new biomass-fired boilers
SO_2	0.005	3-Hour	Protective of NAAQS; based on source test results

We believe that the information provided in this letter addresses the information requested by Region 9, and should be considered to amend the submitted PSD permit application. Please let me know if Region 9 requires any additional information to finalize the draft permit. If you or your staff has any additional questions or need additional information, please do not hesitate to contact me at 425.412.1804.

Sincerely yours,
ENVIRON INTERNATIONAL, INC.

Eric Albright

Eric Albright
Senior Manager

Enclosures

cc: Omer Shalev, USEPA, Region 9
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