Supplemental Responses to Sierra Club Data Requests: Nos. 1 through 97

Amended Application for Certification for HYDROGEN ENERGY CALIFORNIA (08-AFC-8A) Kern County, California

Prepared for:
Hydrogen Energy California LLC

hydrogen energy california

Submitted to:

California Energy Commission

U.S Department of Energy

Prepared by:

URS

October 2012

SUPPLEMENTAL RESPONSES TO SIERRA CLUB DATA REQUESTS

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SIERRA CLUB DATA REQUESTS

TABLES

LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

ACC	air-cooled condenser
AFC	Application for Certification
BACT	Best Available Control Technology
BGRP	Brackish Groundwater Replacement Program
BVWSD	Buena Vista Water Storage District
CEC	California Energy Commission
CCPI	Clean Coal Power Initiative
COC	Condition of Certification
DOE	Department of Energy
ERC	Emission Reduction Credit
HAP	Hazardous Air Pollutant
HECA	Hydrogen Energy California
LDAR	Leak Detection and Repair
MATS	mercury and air toxics standards
PM	particulate matter
PM_{10}	particulate matter 10 microns in diameter or less
PSA	Preliminary Staff Assessment
PSD	prevention of significant deterioration
PTE	potential to emit
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_X	oxides of sulfur
TAC	Toxic Air Contaminant
VOM	volatile organic matter

BACKGROUND: PROJECT FUNDING BY THE DEPARTMENT OF ENERGY

The U.S. Department of Energy ("DoE") is proposing to provide financial assistance to HECA for project definition, design and construction, and demonstration of the Project under the Clean Coal Power Initiative ("CCPI") program, Round 3. (AFC, Appx. B, p. B-3.) The AFC states that the purpose and need for DOE action— providing limited financial assistance to the Project—is "to advance the CCPI program by funding projects that have the best chance of achieving the program's objectives as established by Congress: The commercialization of clean coal technologies that advance efficiency, environmental performance, and cost competitiveness well beyond the level of technologies that are currently in commercial service." (AFC, Appx. B, p. B-1.)

DOE's financial assistance (or "cost share") would be limited to $408 million, which is approximately 10 percent of the HECA Project's total cost. DOE would share the costs of the gasifier, syngas cleanup systems, a combustion turbine, a heat recovery steam generator, a steam turbine, supporting facilities and infrastructure, and a demonstration phase in which the HECA Project would use at least 75 percent coal (calculated on a fuel thermal input basis) to generate low-carbon electricity and low-carbon nitrogen-based products and would capture carbon dioxide ("CO_2") for use in enhanced oil recovery ("EOR") and sequestration. (AFC, Appx. B, pp. B-2 – B-4.) So far, the DOE has invested $54 million in the Project.[4] Funding would be fully or partially appropriated by the American Recovery and Reinvestment Act of 2009.

The AFC does not adequately demonstrate that the Project's technology components and their integration would adequately advance the CCPI's objectives to justify funding by the DOE.

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[4] Hydrogen Energy California, SCS Energy Agrees to Take Over HECA and to Move Project Forward, May 23, 2011; http://hydrogenenergycalifornia.com/uncategorized/scs-energy-agrees-to-take-over-heca-and-to-move-project-forward.

DATA REQUEST

4. Gasification of petroleum coke ("petcoke") and coal has long been demonstrated successfully on a commercial scale and numerous gasification plants operate around the world including several in the U.S. Here, the Project would use Mitsubishi Heavy Industries ("MHI") gasification technology. This technology has been demonstrated on a variety of coal and other feedstocks in pilot facilities, demonstration plants and on a commercial scale at the 250-MW integrated gasification combined cycle ("IGCC") Facility in Nakoso, Japan, which has been in operation since 2008. (AFC, p. 2-74.) Please explain why the use of the MHI gasification technology for the Project is novel and qualifies for CCPI funding.

RESPONSE

As stated in the background section related to this Data Request, gasification has been demonstrated on a commercial scale in the United States and around the world. The Hydrogen Energy California (HECA) Project's qualification for Clean Coal Power Initiative (CCPI) funding is a determination that was made by the U.S. Department of Energy (DOE). Please refer to Appendix B of the Amended Application for Certification (AFC) for further explanation of DOE's analysis and determination. The HECA Project will advance the state of the art in low carbon power generation and manufacturing by demonstrating the integration of previously proven technologies with carbon capture and sequestration on a commercial scale. This is an example of the kind of creative thinking needed to solve the climate crisis.

BACKGROUND: EMISSION ESTIMATES FOR FUGITIVE DUST DURING CONSTRUCTION

The estimates for fugitive dust emission from Project construction are based on a number of assumptions that appear to be not representative for the Project site.

DATA REQUEST

27. The AFC, Appendix E-2, p. 40, estimates emissions of fugitive dust particulate matter from paved roads during Project construction based on an equation from U.S. EPA's Compilation of Air Pollutant Emission Factors ("AP-42"), Section 13.2.1, Paved Roads. Fugitive dust emissions from paved roads have been found to vary with the "silt loading" present on the road surface as well as the average weight and speed of vehicles traveling the road. (The higher these values, the higher the estimated emissions.) The AFC uses the default silt loading value for Kern County from URBEMIS 9.2 (urban emissions model) of 0.031 grams per square meter ("g/m2") Use of this default silt loading value underestimates fugitive dust emissions from paved roads. The silt loading default value used in URBEMIS 9.2 applies only to operational traffic associated with a project (contained in module Operational Data), not the construction phase of a project. Re-entrained road dust emissions estimated with URBEMIS 9.2 assume traffic on a variety of public roads and freeways throughout the county and an average vehicle weight representing passenger cars as well as heavier vehicles. Here, during construction, traffic will mostly consist of heavy-duty equipment and trucks and use local roads which experience deposition of soils from agricultural activities and mud/dirt carryout from the construction site and are less frequently traveled. Thus, emissions of fugitive dust are likely substantially underestimated.

a) Would the Applicant be willing to conduct a silt loading study for the roads leading to the Project construction site?

RESPONSE

a. Silt loading on the local roads near the Project Site during construction should not be impacted, because the Project will implement aggressive mitigation measures to ensure minimal trackout. It is expected that the same mitigation measures included as Air Quality Conditions of Certification (COCs) in the August 2010 California Energy Commission (CEC) Preliminary Staff Assessment (PSA) (08-AFC-8) will be required by the CEC. Specific mitigation measures included in the PSA that will be implemented to minimize trackout onto local roads from construction include:

AQ-SC3 (e) All construction equipment vehicle tires shall be inspected and washed as necessary to be cleaned free of dirt prior to entering paved roadways.

AQ-SC3 (f) Gravel ramps of at least 20 feet in length must be provided at the tire washing/cleaning station.

AQ-SC3 (g) All unpaved exits from the construction site shall be graveled or treated to prevent track-out to public roadways.

AQ-SC3 (k) At least the first 500 feet of any paved public roadway exiting the construction site or exiting other unpaved roads en route from the construction site or construction staging areas shall be swept as needed (less during periods of precipitation) on days when

construction activity occurs or on any other day when dirt or runoff resulting from the construction site activities is visible on the public paved roadways.

During construction, traffic on the local roads due to the Project will consist mainly of worker vehicles and some delivery trucks. Heavy-duty construction equipment will not travel along the local roads. The silt loading used in the fugitive dust emission calculations is appropriate for the roads near the Project Site; therefore, a silt-loading study is not necessary.

DATA REQUEST

31. The average soil moisture content at five feet depth is not representative for most soils that will be moved during bulldozing/earth clearing activities on site. Unless these activities occur after sustained rainfalls or the area is wetted first, the moisture content in the surficial soil layers is considerably lower than at five feet and will therefore result in more dust emissions. For example, of the five soil borings that were taken at the Project site, the soil moisture content of the upper two to five feet were indicated once as "dry to slightly moist," twice as dry to moist," and twice as "moist." Further, the soil moisture content is affected by precipitation and irrigation. Review of the soil boring logs indicates that samples were taken in January of 2009 and the use at the time was indicated as agricultural. Thus, due to the time of year and use of the land, these samples may not be representative of the fallow land that would be graded. Please identify an appropriate soil moisture content for the soils at the site.

RESPONSE

The soil moisture content and silt content used in estimating the bulldozing and earth-clearing fugitive emissions are representative because they were from onsite measurements. The Project Site is not currently fallow; it is being actively farmed. During the earth-clearing activities, excavations may be as deep as 5 feet. Dust suppression through watering will occur to ensure the Project minimizes dust and complies with San Joaquin Valley Air Pollution Control District (SJVAPCD) Regulation VIII, and CEC COCs. The appropriate soil moisture content has been used for the soils at the Project Site.

BACKGROUND: FLARE MALFUNCTION EMISSIONS

The AFC's emission estimates accounts for flare emissions from normal operations and for two planned startup/shutdown events per year. (AFC, Appx. E-3, p. 12.) These estimates do not include emissions that occur during malfunctions which can be substantially higher than during planned events. (Consequently, the AFC's air quality modeling also did not include malfunction events and, thus, did not model maximum 1-hour impacts.) A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flares due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, pressure surges, etc.

The EPA has taken the position that startup, shutdown and malfunction emissions must be strictly prohibited or included in the potential to emit.[29] Most recently, the EPA objected to the proposed Title V and prevention of significant deterioration ("PSD") permit for the Cash Creek coal-to-synthetic natural gas facility in Kentucky because, amongst other issues, the permitting agency's determination of potential to emit ("PTE") for the facility did not account for shutdown and malfunction emissions from the flare.[30] The EPA also recently objected to the proposed Title V permit for the Kentucky Syngas facility for failing to account for shutdown and malfunction emissions from the flare.[31] Similar to the Cash Creek decision, the EPA again emphasized the need to account for all actual emissions including those from all flaring events to ensure compliance with source-wide limits.

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[29] See U.S. Environmental Protection Agency, Order Responding to Petitioners Request that the Administrator Object to Issuance of State Operating Permit from the EPA Administrator regarding BP Products North America, Inc., Whiting Business Unit, Permit No. 089-25488-00453, October 16, 2009. See also Steven C. Riva, U.S. Environmental Protection Agency, Region 2, Letter to William O'Sullivan, New Jersey Department of Environmental Protection, February 14, 2006.

[30] U.S. Environmental Protection Agency, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012.

[31] U.S. Environmental Protection Agency, In the Matter of Kentucky Syngas, LLC, Muhlenberg County, Kentucky, Title V/PSD Air Quality Permit No. V-09-001, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-9, June 22, 2012.

DATA REQUEST

62. Please estimate criteria pollutant and TAC/HAP emissions from the gasifier, SRU and Rectisol flares during malfunction events and update the facility's potential to emit ("PTE") those pollutants.

RESPONSE

As described in "Steven C. Riva, U.S. Environmental Protection Agency, Region 2, Letter to William O'Sullivan, New Jersey Department of Environmental Protection, February 14, 2006," the potential to emit (PTE) must be calculated based on the worst-case emission scenario, taking into account startups, shutdowns, and anticipated malfunctions. The Amended AFC presents emissions from each flare, incorporating anticipated startups and shutdowns. Given the reliability of the subject equipment, there are no anticipated malfunctions; therefore, no emissions associated with such events are included in the PTE.

DATA REQUEST

63. Please review the PSD requirements for the facility based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As stated in the Applicant's response to Data Request 62, because there are no anticipated malfunctions, neither the PTE nor the prevention of significant deterioration (PSD) requirements change.

DATA REQUEST

64. Please review the facility's minor source status for HAPs based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As stated in the Applicant's response to Data Request 62, the PTE was calculated on a worst-case basis, so the minor source status for hazardous air pollutants does not change.

DATA REQUEST

65. Please provide updated air quality modeling for maximum 1-hour impact based on maximum hourly emissions from the flares during malfunction events.

RESPONSE

As stated in the Applicant's response to Data Request 62, because there are no anticipated malfunctions, modeling has not been conducted for them. Modeling was conducted for the maximum 1-hour flaring startup or shutdown event from each flare, and was presented in the Amended AFC.

DATA REQUEST

66. Please provide an updated health risk assessment based on a revised PTE that includes malfunction emissions from the flares.

RESPONSE

As stated in Applicant's response to Data Request 62, there are no anticipated malfunctions. Therefore, the Toxic Air Contaminant/Hazardous Air Pollutant (TAC/HAP) emissions of the Project do not change. Thus, the health risk assessment was not revised.

DATA REQUEST

68. The Water Usage Minimization Study, which is now 4 ½ years old (dated January 2008), was conducted for the prior Project proposal which was based on different equipment, did not include a manufacturing complex, and had only one cooling tower for the power block. (See 08-AFC-08, Appx. X.) The 2008 Water Minimization Study is not adequately documented.

a) Please provide all spreadsheets supporting the tables and conclusions in this study.

b) The study indicates that "[h]eat and material balances "from the Phase 3-Prefeed Package" was used as a basis. This information is not provided. Please provide the Phase 3-Prefeed Package including the material balances used for this study.

c) The study indicates that much of the information in this report is "derived from Thermoflex, a power cycle simulator developed by Thermoflow" "which solves the heat and material balance, calculates performance and estimates equipment pricing." This information was used to develop the cost differences for 100% water-cooled condenser, a 100% air-cooled condenser, and a parallel cooling system. The AFC provides no discussion of the adequacy of this study for the Project's three cooling towers other than stating that "the relative cost of controlled PM is expected to remain similar." (AFC, Appx. E 11, p. 46.) This statement does not provide adequate proof to support the AFC's conclusion that BACT for the cooling tower is a wet-cooled condenser; e.g., many of the operating parameters and heat and material balances used to determine costs in Thermoflex have changed.

i. Please provide the study' input values for the Thermoflex modeling and provide a quantitative discussion how the Project's redesign would change these values.

ii. Please discuss why the relative cost of controlled PM is expected to remain similar even though heat and material balances are different for the Project's current configuration.

RESPONSE

The 2008 water minimization study was conducted to provide economic and environmental information to support selection of the most appropriate cooling method to be used by the HECA Project. As indicated in response to Sierra Club Data Request 71, although the specific details of the study are no longer applicable, because the underlying technologies are similar, an update of the underlying assumptions continues to conclude that the water-cooled condenser system is the appropriate system for the HECA Project. The Applicant believes that the use of dry cooling in this application would be economically unsound and environmentally undesirable, and benefits for the Buena Vista Water Storage District (BVWSD) would not be achieved.[1]

[1] Withdrawal of impaired-quality groundwater to alleviate impacts on agriculture is consistent with the Drainage Control and Irrigation Conservation Programs described in the BVWSD Groundwater Management Plan (Boyle Engineering, 2002) and is part of BVWSD's Brackish Groundwater Replenishment Program (BGRP), which provides benefits for BVWSD's Buttonwillow Service Area. BVWSD's BGRP was analyzed in the Final Environmental Impact Report for the BVWSD's Water Management Program, dated December 2009 (Krieger and Stewart, Incorporated, 2009).

Further support for economic comparison is provided by referencing two technical reports prepared for the CEC titled "*Cost and Value of Water Use at Combined-Cycle Power Plants"* (CEC, 2006), and "*Comparison of Alternate Cooling Technologies for California Power Plants: Economic, Environmental and Other Tradeoffs*" (CEC, 2002). These studies provide a comparison between water- and dry-cooled configurations for power plants in four different California geographies, with correspondingly different typical meteorological conditions. Of particular relevance to HECA, each study has a "Valley" location case that features a comparison of cooling methods for a combined-cycle power plant located in Kern County. The 2006 CEC report provides a further description for the Valley site as follows**: "…**while still having high summertime temperatures, represents a more moderate climate than the desert site. At this location, fresh water is highly valued by the agricultural community, but saline groundwater, which is unsuitable for irrigation, is available" (CEC, 2006). The CEC reports are a relevant comparison because:

- The location and meteorological conditions between HECA and the CEC "Valley" site are the same.
- The cooling loads for both plants are similar. Both also have similar steam turbine output and condenser loads.
- Annual average brackish/saline water consumption for the combined cycle is similar between the reports and the HECA plant design.

The CEC water minimization studies provide information and support for selection of a water-cooled condenser for the combined-cycle power plant. The CEC reports indicate that the HECA Project would incur the following impacts associated with use of an air-cooled condenser (ACC):

- Capital cost differential of approximately $20 to $30 million
- Reduced power output of between 20 to 40 megawatts (range of 2002 and 2006 study results)
- Overall total cost impact of about $50 million (2002 study).

References

Boyle Engineering Corporation, 2002. Groundwater Status and Management Plan for Buena Vista Water Storage District.

California Energy Commission (CEC), 2002. Comparison of Alternate Cooling Technologies for California Power Plants: Economic, Environmental and Other Tradeoffs. CEC 500-02-079F. February.

California Energy Commission (CEC), 2006. Cost and Value of Water Use at Combined-Cycle Power Plants. CEC-500-2006-034. April.

Krieger and Stewart, Incorporated, 2009. Final Environmental Impact Report for the Buena Vista Water Storage District Buena Vista Water Management Program. December.

DATA REQUEST

69. Because of the non-attainment status of the San Joaquin Valley with state and federal national ambient air quality standards for PM10, the Project would require offsets. The Applicant proposes to use SO2 interpollutant emission reduction credits ("ERCs") to offset PM10 emissions. (AFC, Appx. E-10-1). The cost of these ERCs was not factored into the AFC's cost-effectiveness analysis for air-cooled vs. water-cooled condensers.

a) Please identify the purchase price of the SO2 ERCs for PM10 interpollutant offsets that have been or would be acquired for the Project (ERC C-1058-5: $98,000 stpd; ERC C-3275-5: 168,000 stpd).

b) Please include the costs for these ERCs in your revised cost-effectiveness analysis.

RESPONSE

a. The sulfur dioxide Emission Reduction Credits (ERCs) for particulate matter 10 microns in diameter or less (PM_{10}) interpollutant offsets (ERC C-1058-5: 98,000 short tons per day; ERC C-3275-5: 168,000 short tons per day) were transferred to HECA LLC as part of the purchase and sale agreement with British Petroleum and Rio Tinto in September 2011. The details of this agreement are confidential. However, San Joaquin Valley oxides of sulfur ERC transaction prices have remained fairly stable over the last 5 years (2007–2011), and are detailed in Table 69-1.

Table 69-1
San Joaquin Valley
SO_X ERC Transaction Price

Year	Cost
2007	$21,995
2008	$25,856
2009	$29,242
2010	$21,179
2011	$15,267
July 31, 2012[1]	$25,000

Source: Provided by Evolution Markets. Personal communication August 23, 2012.

Notes:

[1] Most recent data available.

ERC = Emission Reduction Credit
SO_X = oxides of sulfur

b. As noted in the response to Sierra Club Data Request 72a (previously submitted), even the very conservative cost estimate for installation of an ACC far exceeds the most recent cost-effectiveness threshold from the SJVAPCD for PM_{10}.

DATA REQUEST

72. The AFC's calculation of the capital recovery factor ("CRF") assumes 7 percent interest and a 20-year life.

d) Please provide a discussion and estimate of CRF and cost-effectiveness of an air-cooled condenser based on the maximum operating life of the ACC assuming the Project would be operating beyond its 25-year design operating life.

RESPONSE

d. The cost effectiveness of the ACCs far exceeds the SJVAPCD cost-effectiveness threshold (as presented in response to Sierra Club Data Request 72a that was previously submitted). The Project would have to operate for many years beyond the expected operating life of 25 years in order for the cost effectiveness to be brought down to the $11,400-per-ton level set by SJVAPCD. Thus, speculating on whether the Project may operate slightly longer than the expected 25 years does not change the conclusion that the ACCs are not cost-effective.

DATA REQUEST

73. Please provide a complete revised cost-effectiveness analysis based on the EPA's 2002 Cost Control Manual that analyzes wet cooling towers, air-cooled condensers and combinations thereof to satisfy the Project's cooling needs in the various process areas. Please document all assumptions and calculations taking into account your responses to the above data requests.

RESPONSE

The response to Sierra Club Data Request 72a (previously submitted) shows that when considering only the capital cost for ACC, this cost far exceeds the most recent cost-effectiveness threshold from the SJVAPCD for PM_{10}; therefore, it is not necessary to conduct a complete cost-effectiveness analysis.

DATA REQUEST

81. The AFC, Appx. E-6, p. 65, provides a one-paragraph discussion as a BACT analysis for fugitive emissions from equipment leaks. The AFC, p. 5.1-24, proposes as BACT to apply an LDAR program in select process areas including the gasification block, Area #1 (methanol), Area #5 (propylene), Area #7 (hydrogen sulfide-laden methanol), Area #9 (acid gas), and Area #10 (ammonia-laden gas) and all portions of the manufacturing complex. The AFC's one-paragraph discussion is not acceptable as a BACT analysis for the Project's fugitive equipment leaks because it fails to follow the five-step top-down methodology recommended by the EPA in its New Source Review Manual. Please provide such an analysis. This analysis should identify and analyze the use of leakless components (e.g., welded connectors, bellows valves, double mechanical seals with high pressure fluids on pumps, enclosed distance pieces on compressors with venting to a control device, etc.) as well as routing any fugitive emissions from pressure releases from pressure relief valves to a control device.

RESPONSE

At the Taylorville Energy Center, the approved Best Available Control Technology (BACT) for fugitives from equipment leaks included Leak Detection and Repair (LDAR) in the high volatile organic matter (VOM) process areas, and use of good work practices on low VOM streams. It is not unprecedented for BACT to include LDAR on only select process areas.

Kentucky NewGas BACT for fugitives from equipment leaks was determined to be LDAR in select process areas, with pressure relief valves routed to a flare.

Hyperion Energy Center's BACT for fugitives from equipment leaks was determined to be LDAR, with enhanced work practices and enforceable limits on the percent of components leaking.

The Applicant was unable to identify a single project that did not eliminate leakless components on the basis of cost-effectiveness, with the cost of control in one of these projects at $80,000 per ton of volatile organic compounds. Based on this information, the cost from these projects is over the SJVAPCD cost-effectiveness threshold; therefore, the use of leakless components would not be cost-effective for the HECA Project.

BACKGROUND: MERCURY AND AIR TOXICS STANDARDS

The U.S. EPA recently promulgated the so-called mercury and air toxics standards ("MATS") to limit emissions of mercury, acid gases and other toxic pollution from power plants. (FR Vol. 77, No. 32, February 16, 2012.) Effective April 16, 2012, MATS establishes emission limits for new IGCC electric generating units (such as the HECA project) for filterable particulate matter ("PM") of 7.0E–2 pounds per Megawatt-hour ("lb/MWh") (beyond-the-floor limit) or 9.0E–2 lb/MWh (for units with duct burners on syngas); hydrogen chloride ("HCl") of 2.0E–3 lb/MWh; and mercury ("Hg") of 3.0E-3 pounds per Gigawatt-hour ("lb/GWh"). MATS also provides alternate equivalent emission standards: SO2 as a surrogate for HCl of 4.0E-1 lb/MWh and individual non-mercury metals and total non-mercury metals as a surrogate for filterable PM. (FR Vol. 77, No. 32: 9367-9368, February 16, 2012.) The AFC does not address the Project's compliance with MATS requirements.

The AFC estimates emissions of 7.63E-3 tons/year of Hg from the turbine/heat generator and coal dryer stacks. (AFC, Appx. M, p. 1.) Based on an annual electricity generation of 2,699,860 MWh/year for mature operations (AFC, Appx. E-6, p. 3), Project emissions rates can be estimated at 5.7 E-3 lb/GWh of Hg[33], indicating that the Project may not be able to demonstrate compliance with the mercury emission standard of 3.03E-3 lb/GWh of Hg under MATS.

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33 Mercury: (7.63E-3 tons/year of Hg) / (2,699,860 MWh/year) × (2,000 lb/ton) × (1,000 MWh/GWh) = 5.7E-3 lb/GWh of Hg; MATS standard = 3.03E-3 lb/GWh of Hg.

DATA REQUEST

82. Please provide a quantitative analysis of the Project's emission rates of PM or surrogate, Hg, and HCl or surrogate. Please document all your assumptions.

RESPONSE

Emissions of particulate matter (PM), mercury, and hydrogen chloride are presented in the Amended AFC. Emissions of PM are presented in Amended AFC, Appendix E-3. Emissions of mercury and hydrogen chloride are presented in Amended AFC, Appendix M. Please see page 2 of Appendix M for details of the mercury calculations.

DATA REQUEST

83. Please discuss how the Project would demonstrate compliance with the emission limits established under MATS.

RESPONSE

Please see the response to CEC Data Request A135 previously submitted.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT
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AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
(Revised 10/8/12)

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DECLARATION OF SERVICE

I, Dale Shileikis, declare that on October 12, 2012, I served and filed a copy of the attached Supplemental Responses toSierra Club Data Requests: Nos. 1 through 97, dated October, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at:
http://www.energy.ca.gov/sitingcases/hydrogen_energy/index.html

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:
(*Check all that Apply*)

For service to all other parties:

__x__ Served electronically to all e-mail addresses on the Proof of Service list;

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For filing with the Docket Unit at the Energy Commission:

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CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 08-AFC-08A
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

____ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
michael.levy@energy.ca.gov

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.