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August 2, 2012

Hydrogen Energy California, LLC
Marisa Mascaro
Senior Environmental Project Manager
SCS Energy LLC
30 Monument Square, Suite 235
Concord, MA 01742
Enclosure: Data Request Packet
CC: Docket 08-AFC-8A
POS List

Re: HYDROGEN ENERGY CALIFORNIA PROJECT (08-AFC-8A), Sierra Club's Data Requests , Set No. 1

Dear Ms. Mascaro:

Pursuant to Title 20, California Code of Regulations, section 1716, the Sierra Club requests the information specified in the enclosed data requests.

These data requests are numbered 1 through 97. Written responses to the enclosed data requests are due to the Sierra Club on or before September 3, 2012.

If you are unable to provide the information requested, need additional time, or object to providing the requested information, please send a written notice to me and the Committee within 20 days of receipt of this notice. The notification must contain the reasons for the inability to provide the information or the grounds for any objections (*see* Title 20, California Code of Regulations, section 1716 (f)).

If you have any questions regarding the enclosed data requests, please feel free to contact me.

Sincerely,

Andrea Issod, Staff Attorney
Sierra Club Environmental Law Program
85 Second St, Second Floor
San Francisco, CA 94105
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(415) 977-5544

Sierra Club
HECA
Data Requests Set No. 1

August 2, 2012

GENERAL

Background: DEMAND FOR GENERATION CAPACITY IN CALIFORNIA

The AFC, p. 1-15, defines one of the Project objectives as providing "dependable low-carbon electricity to help meet future power needs and "back-up" intermittent renewable power sources, such as wind and solar, to support a reliable power grid. The AFC, p. 6-3, claims that the combination of continued population growth in California (at a rate of just over one percent until 2030) and long-term economic prosperity will result in robust growth in energy demand. The AFC provides no support for these claims.

To the contrary, recent studies have shown that California's population is now projected to grow more slowly than anticipated (slightly less than 1% per year until 2030 and slowing down to 0.6% by 2050.)[1] Even without factoring in these recent findings with respect to population growth, the California Public Utilities Commission ("CPUC") recently found clear evidence that "additional generation is not needed by 2020" and ruled to defer any new procurement of fossil fuel generation. This ruling establishes for most of the state, that California's long-term energy needs do not require building more fossil fuel infrastructure. The ruling further explains that "[w]hile the focus of this proceeding extends out to 2020, it is important to note that the record similarly does not support a finding of need for additional generation beyond 2020." Accordingly, the agency found that "it is also reasonable to defer procurement of generation for any estimated need after 2020."[2]

At present, excess generation capacity exists in California. For example, Calpine Corporation's 572-MW natural-gas fired Sutter Energy Center combined cycle power plant recently faced imminent retirement. Only intervention by the CPUC, which ordered Pacific Gas & Electric, Southern California Edison, and San

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[1] John Pitkin and Dowell Meyers, California Demographic Futures, Generational Projections of the California Population by Nativity and Year of Immigrant Arrival, April 2012; http://www.usc.edu/schools/price/futures/pdf/2012_Pitkin-Myers_CA-Pop-Projections.pdf.

[2] California Public Utilities Commission, Decision on System Track I and Rules Track III of The Long-Term Procurement Plan Proceeding and Approving Settlement, Rulemaking 10-05-006, filed May 6, 2010; http://docs.cpuc.ca.gov/PUBLISHED/AGENDA_DECISION/164031.htm#P27_410.

Diego Gas & Electric to enter negotiations with the Sutter Energy Center's owner, Calpine Corporation, to offer a contract to keep the plant online in 2012, averted shutdown of the plant.[3]

Data Requests:

1. Please explain why the Applicant proposes to build a new fossil fuel-fired baseload plant when there does not appear to be any demand for additional generation capacity in the state until at least 2020.

2. Please discuss whether the Applicant is in discussions for a power purchase agreement with any utilities. If yes, please indicate which utilities and produce documents related to those discussions.

3. Please indicate the anticipated price of electricity that would be generated by the Project and compare to the price of electricity generated by natural gas-fired combined-cycle facilities in California.

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,

[3] California Public Utilities Commission, Energy Division Resolution E-4471, March 22, 2012; http://docs.cpuc.ca.gov/published/Final_resolution/162985.htm.

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.

Data Requests:

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.

5. When the DOE selected the HECA project as one of the projects for demonstration and funding under DOE's CCPI Round 3, the Project was proposed with gasification technology and combustion and steam turbine generators developed and manufactured by the U.S. firm General Electric ("GE"). The Project design has since undergone significant design changes and now proposes to use gasification technology and combustion and steam turbine generators developed and manufactured by the Japanese firm MHI.

    a) Please discuss in detail why the Applicant decided not to use GE gasification and turbine technology and instead to use MHI technologies.

    b) Has the DOE been apprised of the changes in the technological configuration and commercial issues of the Project?

    c) Please explain whether DOE can legally invest in Japanese technology with funds that are partially or fully appropriated by the American Recovery and Reinvestment Act.

    d) Please discuss the economics for the Project.

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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.

e) Would the Project be able to go forward if the Applicant does not receive funding from DOE?

6. The AFC, p. 2-8, recognizes that the Project's key technologies – integrated gasification combined cycle, carbon capture and storage ("CCS"), and EOR – have long been used separately and safely. However, the AFC, p. 2-73, states that while "both gasification and gas purification with carbon capture are proven technologies, operating at commercial scale within the United States and around the world," "integration of these technologies with sequestration has not yet been performed on a commercial scale."

   a) Please discuss technological and other problems associated with integrating gasification and gas purification technologies with carbon capture and sequestration on a commercial scale. Please discuss issues that would be specifically addressed and "proven" by the Project.

   b) Since 2000, CO_2 captured at the Dakota Gasification Company's coal gasification plant near Beulah, North Dakota, is compressed and transported via pipeline about 200 miles north to southeast Saskatchewan, Canada, for use in EOR and sequestration. The Weyburn-Midale CO_2 Project has been injecting about 7,700 and 2,000 short tons per day ("stpd") at Cenovus's Weyburn and Apache's Midale oil fields, respectively, since 2006. (*See* http://www.ptrc.ca/weyburn_history.php and http://www.ptrc.ca/weyburn_final.php.) The annual CO_2 injection, about 3.5 million short tons per year ("stpy")[5], is on the same order of magnitude as the proposed CO_2 injection for the Project of 3 million stpy. (AFC, p. 1-2.)

      i. Please discuss why the Weyburn-Midale CO_2 Project does not constitute commercial demonstration of integrating large-scale injection of pipeline CO_2 from gasification and carbon capture for purposes of EOR.

      ii. Please discuss any differences with respect to the integration of CO_2 capture and subsequent transportation and injection for purposes of EOR and sequestration between a) the Weyburn/Midale CO_2 Project and b) the planned CO_2 capture at HECA and subsequent transportation to and injection of CO_2 at Elk Hills Oil Field.

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[5] Estimated from: (Weyburn: 7,000 tonnes/year + Midale: 1,800 tonnes/year) × (1.1 short tons/tonne) × (365 days/year) = 3.54 million stpy.

7. DOE states that its overarching goal for CCPI Round 3 projects was to demonstrate technologies at commercial scale in a commercial setting that would: (1) operate at 90 percent capture efficiency for CO_2; (2) make progress towards capture and sequestration at less than a 10 percent increase in the cost of electricity for gasification systems and a less than 35 percent increase for systems; and (3) make progress toward capture and sequestration of 50 percent of the facility's CO_2 output at a scale sufficient to evaluate the full impacts of carbon capture technology on a generating plant's operations, economics and performance. Please provide a detailed discussion how the Project would meet each of these objectives. Please document your assumptions.

Background: PROJECT FUNDING BY THE CALIFORNIA PUBLIC UTILITIES COMMISSION

In 2009, the Applicant received authorization from CPUC to recover up to $30 million in costs stemming from the Applicant's co-funding of the HECA feasibility study ($17 million in funding for Phase I assessing initial feasibility and $13 million for the Phase II Front End Engineering Design ("FEED") study). The $30 million of funding constitutes approximately 20 percent of the $152 million budgeted for Phase I and II studies. [6] The CPUC's decision, in part, relied upon the finding that the Project would not be so duplicative of the reports the Applicant was producing in its feasibility study for the Clean Hydrogen Power Generation ("CHPG") project in Utah or of efforts by BP, Rio Tinto, and Edison Mission Group for the Carson Project in Southern California that the feasibility studies would fail to produce benefits that make it reasonable to authorize recovery of costs in rates. One argument for demonstrating the difference between the CHPG and the HECA project for Phase II costs was that "CHPG is a coal fed project, while HECA uses petroleum coke."

Data Requests:

8. Has the Applicant spent the entire $30 million approved by the CPUC for reports produced for the feasibility study of the previously proposed HECA project? Please provide a breakdown of costs for Phase I and Phase II.

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[6] California Public Utilities Commission, Application of Southern California Edison Company (U338E) For Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California IGCC with Carbon Capture and Storage, Application 09-04-008, filed April 3, 2009, Decision 09-12-014, December 3, 2009, issued: December 9, 2009; http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/110973.htm.

9. Please provide a list of all reports produced for the feasibility study for the previously proposed HECA project separately for Phase I and Phase II. Please provide a copy of the reports.

10. The technological configuration and commercial issues for the Project have changed considerably since the Applicant received authorization from CPUC for cost recovery for a feasibility study. For example, the Project is now designed with one instead of two gasifiers which use different technology, would use a 75%/25% coal/petcoke blend instead of 100% petcoke, and would include a fertilizer manufacturing facility.

    a) Please discuss which reports produced for the feasibility study authorized by the CPUC apply to the current Project configuration without changes and which require changes.

    b) Please describe or provide the additional reports that must be conducted for determining the feasibility of the current Project configuration.

    c) Has the CPUC been apprised of the changes in the technological configuration and commercial issues of the Project?

    d) Will the Applicant apply with the CPUC for authorization of additional cost recovery for reports produced for determining the feasibility of the current Project configuration?

Background: REFERENCES

The AFC cites to a number of references to support its assumptions that are not readily available in the public domain and are not provided in the current record.

Data Requests:

11. Please provide a copy of the following references:

    a) HECA (Hydrogen Energy California) Project Team, 2008. Field work and observations. (AFC, Section 5.8.)

    b) Sierra Scientific Services, 2009. An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project. (AFC, Section 5.14.)

c) Boyle Engineering Corporation, 2002. Groundwater Status and Management Plan for Buena Vista Water Storage District. (AFC, Section 5.14.)

d) Buena Vista Water Storage District, 2009. Personal communication with URS. May. (AFC, Section 5.14.)

e) Environmental Data Resources, Inc. (EDR), 2009. Data Map Well Search Report, April 3, 2009. (AFC, Section 5.14.)

f) ESA, 2010. Groundwater Banking Project Environmental Impact Report. Prepared for West Kern Water District. March. (AFC, Section 5.14.)

g) Sierra Scientific Services, 2003. Determination of Aquifer Storage Capacity for the Rosedale-Rio Bravo Water Storage District, Bakersfield, California. January 20. (AFC, Section 5.14.)

h) Sierra Scientific Services, 2004. An Evaluation of Well Placements and Potential Impacts of the ID4/Kern Tulare/Rosedale—Rio Bravo Aquifer Storage and Recovery Project. July 20. (AFC, Section 5.14.)

i) Sierra Scientific Services, 2007a. A Water Quality Evaluation of the Strand Ranch Aquifer Storage and Recovery Project, Kern County, CA., in: Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report, January, 2008, prepared by ESA, Los Angeles, California. December 19. (AFC, Section 5.14.)

j) Sierra Scientific Services, 2007b. An Evaluation of Well Placements and Potential Impacts of the proposed Strand Ranch Well Field, Kern County, California. In "Rosedale—Rio Bravo Water Storage District Strand Ranch Integrated Banking Project Environmental Impact Report," January 2008, prepared by ESA, Los Angeles, California. December 20. (AFC, Section 5.14.)

k) Sierra Scientific Services, 2009. An Evaluation of the Geology, Hydrology, Well Placements and Potential Impacts of the Buena Vista Water Storage District's proposed Brackish Groundwater Remediation Project. In prep. (AFC, Section 5.14.)

l) URS, 2009a. Preliminary Geotechnical Investigation for Proposed Hydrogen Energy California Project (HECA), Kern County, California. (AFC, Section 5.14.)

m) URS 2010b. Draft Addendum to the Draft Hydrogeologic Data Acquisition Report for Proposed Hydrogen Energy California Project (HECA), Kern County, California. April 2010. (AFC, Section 5.14.)

n) URS 2010c. Linear Modifications to the Revised Application for Certification for Hydrogen Energy California, Kern County, California. August 2010. (AFC, Section 5.14.)

Background: MATERIAL MASS BALANCES

The AFC does not provide adequate material mass balances necessary to understand the facility's various technologies, *e.g.,* gasification and fertilizer manufacturing process, and associated emission sources. Further, the information provided on product flows is inconsistent.

Data Requests:

12. Please provide material mass balances for the facility including water, carbon, sulfur, nitrogen, methanol, volatile organic compounds ("VOCs"), hazardous air pollutants ("HAPs") and toxic air contaminants ("TACs"), and inert solids. These mass balances should clearly identify all individual process streams and the respective compound streams and emission points.

13. The overall component balances provided in AFC, Figure 2-13 for sulfur, carbon, and inert solids are inconsistent with the maximum amounts of products shown in AFC, Tables 2-10 and 2-11: For sulfur, Table 2-11 indicates a total production of 150 stpd of sulfur; in contrast, Table 2-10 and Figure 2-13 indicate a total production of 8,370 lb/hr of sulfur (Process Stream #4) or 100 stpd of sulfur.[7] For carbon, Tables 2-10 and 2-11 indicate a total flow rate of 9,200 stpd CO_2 for EOR; in contrast, Figure 2-13 indicates a total flow rate of 207,655 lb/hr carbon (Process Stream #5) or 9,137 stpd CO_2.[8] For inert solids from gasification, Tables 2-10 and 2-11 indicate a flow rate of 850 stpd; Figure 2-13 indicates a total flow rate of 69,925 lb/hr or 839 stpd.[9] Please discuss these discrepancies.

[7] (8,370 lb/hr) × (24 hours/day) / (2,000 lb/ton) = 100.44 stpd.

[8] (207,655 lb/hr) × (24 hours/day) / (2,000 lb/ton) × (44 g/mol CO_2/12 g/mol C) = 9,136.82 stpd CO_2.

[9] (39,925 lb/hr) × (24 hours/day) / (2,000 lb/ton) = 839.1 stpd.

Background: FEEDSTOCK SUPPLY, DEMAND, AND SPECIFICATIONS

The Project would gasify a blend of 75% western sub-bituminous coal and 25% California petcoke based on thermal input to the gasifier higher heating value ("HHV"). (AFC, p. 2-1.) The AFC provides inconsistent and inadequate information for these feedstocks.

Data Requests:

14. The AFC, pp. 2-15 and 2-16, states that the Project would require 4,580 sptd of coal and 1,140 stpd of petcoke for a total of 5,720 stpd. Elsewhere, the AFC indicates that the Project would require a total of 5,800 stpd of feedstock (as received). (AFC, Table 2-10, p. 2-84, Table 2-11, p. 2-85.) Please discuss this apparent discrepancy.

15. The AFC, p. 2-16, states that the Project would be able to accept a variety of petcoke and coal feedstocks and shows typical analyses for both petcoke and coal (Tables 2-4 and 2-5). Please discuss the ranges of petcoke and coal feedstock specifications (*e.g.,* ultimate analysis, moisture content, gross heating value, sulfur content, chloride content, bulk density, mercury content, ash mineral analysis) that would meet the Project's technology requirements.

16. In the prior AFC for the Project, the Applicant proposed to gasify 100% petcoke with the flexibility to operate with up to 75% thermal input western bituminous coal in a GE gasifier. (*See*, *e.g.,* 08-AFC-08, p. 2-1.) In the initial public workshop, the Applicant indicated that MHI only guarantees a 25% petcoke/75% coal feedstock for the gasifier.

    a) Please discuss why the Applicant has decided to switch to MHI gasification technology.

    b) Please discuss in detail why the gasifier developed by GE is able to operate on 100% petcoke but not the gasifier developed by MHI.

    c) Please discuss whether the Applicant has investigated other gasifier technologies.

    d) Please provide the vendor guarantee for the MHI gasifier.

    e) Please discuss whether the Applicant requested a vendor guarantee from MHI for gasifying any feedstock blend other than 25% petcoke/75% coal. If yes, please discuss the response and include any relevant documents. If not, then please discuss why not.

f) Please discuss whether the MHI gasifier could operate on any other feedstock blend besides 25% petcoke/75% coal, including 50%/50%, 75% coal/25%petcoke, and/or 100% petcoke.

17. The AFC, pp. 2-15 and 2-16, indicates that several mines have been identified that can supply western sub-bituminous coal meeting Project technology requirements in terms of ash composition and other characteristics. At the June 20, 2012 workshop, the Applicant indicated that it would contract with Peabody Energy for supply of sub-bituminous coal from the Lee Ranch Mine in New Mexico. Peabody Energy's Lee Ranch Mine produced about 1.7 million stpy in 2010 and currently supplies coal to the Western Fuels Association and Tucson Electric Power under long-term contracts that run through 2014 and 2010, respectively.[10] The Project would consume about 1.6 million stpy, *i.e.,* 94% of the mine's current production. (AFC, p. 2-15.)

a) Please identify the mines the Applicant has identified that would meet the Project's technology requirements.

b) Please discuss whether the Applicant has procured a contract with Peabody Energy and discuss the specified duration and costs.

c) Please quantify the percentage of the annual coal supply for the Project that would be sourced from Peabody Energy's Lee Ranch Mine in New Mexico. If not 100 percent, please discuss the source(s) of the remainder.

d) Please discuss whether Peabody Energy's Lee Ranch Mine would increase its annual production of coal to accommodate Project demand.

e) Please discuss whether or not Lee Ranch Mine is currently in compliance with all federal and state regulations and describe and detail any litigation the mine has been involved in for the last ten years.

f) Please provide fuel specifications for coal from the Lee Ranch Mine and any other mines under consideration, including heat content; ash content; sulfur, mercury, hydrogen chloride, and heavy metal content; etc.

g) Please identify the rail carrier(s) that would transport coal from the Lee Ranch Mine in New Mexico to California. Please provide any procurement contracts or documents of discussions with the respective rail carrier(s).

[10] Peabody Energy, Fact Sheets, Lee Ranch Mine; http://www.peabodyenergy.com/content/278/Publications/Fact-Sheets/Lee-Ranch-Mine.

18. The AFC, p. 2-16, states that the Project would consume about 400,000 stpy of fuel-grade petcoke which is about 7% of the total 6.0 million stpy petcoke produced in-state by six major California refineries in Los Angeles area and central California.

    a) Please provide a discussion of the total annual petcoke production in California from all sources and the current annual demand for and fate of petcoke from California (e.g., shipment overseas).

    b) Has the Applicant procured contracts or discussed contractual terms with any petcoke manufacturers? Please produce associated documents including phone logs, correspondence, contracts, etc.

AIR QUALITY

Background: VOLUNTARY AIR QUALITY IMPROVEMENT AGREEMENT

According to CEC staff's preliminary determination of compliance ("PDOC") for the previously proposed version of the HECA project, the Applicant "has entered into a voluntary Air Quality Improvement Agreement with the district to fund air quality improvements within Kern County. The funding includes an initial fee of over $680,000 and a potential additional fee depending on whether the district's target NOx emission level is met during a two year demonstration period that starts with commercial operation. This agreement specifies that the initial fee will be paid at the time of commercial operation, unless waived by HECA, and that the additional fee, if necessary, will be paid within 180 days after the completion of the demonstration period. The additional fee is based on an agreed calculation procedure that is not to exceed the equivalent ERC cost for NOx credits. The funds obtained by the district under this agreement are to be used to fund emission reduction projects within the San Joaquin Valley Air Basin, preferentially in Kern County, that will focus on replacing older high emitting agricultural equipment in order to provide quantifiable air quality benefits within Kern County."[11] The AFC contains no discussion of this agreement.

[11] 08-AFC-08, California Energy Commission, August 2010 Preliminary Determination of Compliance, pp. 4.1-42/4.1-43.

Data Requests:

19. Please provide a copy of the Voluntary Air Quality Improvement Agreement ("Agreement") between HECA and the SJVAPCD, if necessary under confidential cover.

20. Please indicate whether HECA believes that the Agreement remains binding for the revised HECA project. If no, please explain why not. If yes,

    a) Please explain under which conditions the Agreement could be waived.

    b) Please provide an inventory of older high-emitting agricultural equipment in the SJVAPCD and in Kern County (including age, expected remaining useful life, horsepower, location) that could be addressed by the Agreement and estimate their annual emissions.

    c) Please identify and discuss any other rules, regulations, and agreements that are expected to reduce emissions from such older high-emitting agricultural equipment. Please specify the time frame in which these rules, regulations, and agreements would take effect and discuss their impact.

    d) Please explain how the fees were calculated and how they relate to HECA's emissions.

21. The Project has been designed for an operating life of 25 years. (AFC, p. 3-1.) Experience with other power plants has shown that their lifetime is frequently extended far beyond their initial life expectancy with some coal-fired power plants now operating in their 60^{th} or even 70^{th} decade. Would the Applicant be willing to commit to funding additional air quality improvement agreements if the Project would operate longer than its expected lifetime?

Background: BACT ANALYSIS

The AFC in Appendix E provides a best available control technology ("BACT") analysis for the Project, dated April 2012. In May 2012, the Applicant submitted a revised BACT analysis as part of the Application for Authority to Construct to the San Joaquin Valley Air Pollution Control District ("SJVAPCD") and the U.S. Environmental Protection Agency ("EPA"). This revised May 2012 BACT analysis appears to provide additional discussion.[12] The Applicant did not provide a discussion of why the BACT analysis was revised and which revisions were made.

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[12] *See*, *e.g.,* May 2012 BACT Analysis, p. 1: "SJVAPCD defines BACT to be…"

Data Request:

22. Please provide a redline strikeout version comparing the two versions of the BACT analysis submitted to the California Energy Commission ("CEC") (April 2012) and to SJVAPCD and EPA (May 2012).

23. Please provide any correspondence with the SJVAPCD relating to the Applicant's Authority to Construct for the Project on an ongoing basis.

Background: EMISSION CALCULATION SPREADSHEETS

The AFC, Appendix E, provides emission estimates for construction and operation of the Project; Appendix M provides emission estimates of TACs and HAPs. These estimates, which do not include any confidential information, are contained in a large number of Excel spreadsheets. The estimates were provided in PDF format which are often nearly illegible when printed due to their small font size. Because calculations often extend over several linked spreadsheets, they are difficult to follow in print as opposed to in electronic format. While most spreadsheets can be re-engineered in electronic format, presuming all assumptions are documented, it is very time-consuming to do so. Further, some calculations cannot be verified because not all information is shown in the printouts.

Data Request:

24. Please provide all Excel spreadsheets used to support the emission estimates in the AFC, Appendices E and M, in their native electronic format and unprotected (*i.e.*, showing formulas), if necessary under confidential cover and/or pass-word protected.[13]

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[13] It is neither unusual nor unreasonable for CEC staff or intervenors to request and for the Applicant to make available Excel spreadsheets containing emission estimates and calculations for health risk assessments. *See,* for example, the following CEC proceedings:

Victorville 2 Solar Gas-Hybrid Power Project: Construction and operational criteria pollutant and TAC emission estimates were provided on CD as password-protected Excel spreadsheets in response to California Unions for Reliable Energy ("CURE") data requests. *See* http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/2007-07-02_APPLICANTS_OBJECTIONS_TO_CURE_DATA_REQUEST_SET_01.PDF and http://www.energy.ca.gov/sitingcases/victorville2/documents/applicant/2007-07-12_RESPONSES_TO_CURE_DATA_REQUEST_SET_01.PDF;

Blythe Solar Power Project: Operational emissions were provided as unprotected Excel spreadsheets in response to CEC staff data requests. *See* http://www.energy.ca.gov/sitingcases/solar_millennium_blythe/documents/applicant/data_responses_set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Blythe%20DR%20Operating%20Emissions.xlsx and http://www.energy.ca.gov/sitingcases/solar_millennium_blythe/documents/applicant/data_responses_

Background: CONSTRUCTION TRAFFIC TRAVEL DISTANCES

The AFC, p. 5.1-9, states that trip distances for estimating off-site construction emissions were based on the assumption that workers and delivery trucks are traveling within Kern County. Appendix E-2, p. 35, shows that the AFC assumes off-site roundtrip distances worker commuting vehicles, delivery trucks, and import fill trucks of between 38.0 to 39.8 miles, *i.e.*, it assumes that all vehicles operate only within a radius of less than 20 miles around the Project site. The AFC does not provide any support for these assumptions. A 20-mile roundtrip distance appears unrealistically short for both the construction workforce and the delivery/fill import vehicles and may therefore underestimate emissions associated with vehicle travel.

Data Requests:

25. According to the AFC, p. 5.8-15, the average size of the workforce over the approximately 49-month construction and commissioning period would be 1,159 workers (including construction workers and contractor staff); the peak month of construction would require 2,090 craft workers (on site) and 371 contractor staff. It appears unlikely that a sufficiently skilled construction labor force would be available in Kern County within a 20 mile radius of the Project site. Further, based on the 1982 report *Socioeconomic Impacts of Power Plants* by the Electric Power Research Institute, construction workers will commute as much as 60 miles daily to construction

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set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Blythe%20Data%20Rrespons e%20Emissions.xlsx;

Palen Solar Power Project: Construction and operational emission estimates were provided as unprotected Excel spreadsheets in response to CEC staff data requests. *See* http://www.energy.ca.gov/sitingcases/solar_millennium_palen/documents/applicant/data_responses_set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Palen%20DR%20Construction%20Emissions.xlsx and http://www.energy.ca.gov/sitingcases/solar_millennium_palen/documents/applicant/data_responses_set_1/Air%20Quality/Air%20Quality%20Supporting%20Documentation/Palen%20DR%20Operating%20Emissions.xlsx;

Bullard Energy Center: Operational emission estimates were provided as unprotected Excel spreadsheets in response to CEC staff data requests. *See* http://www.energy.ca.gov/sitingcases/bullard/documents/applicant/DA-response-1/appendix-A/Attachment-7-1.xls and http://www.energy.ca.gov/sitingcases/bullard/documents/applicant/DA-response-1/appendix-A/Attachment-19-1.xls; and

Riverside Energy Resource Center: Estimates for startup, shutdown, maintenance emissions from turbines and emissions estimates for on-road vehicle travel were provide as unprotected Excel spreadsheets in response to CURE data requests. *See* http://www.energy.ca.gov/sitingcases/riverside/documents/applicants_files/2004-08-10_CURE_DATA_REQ4.PDF and http://www.energy.ca.gov/sitingcases/riverside/documents/applicants_files/cure_set4.

sites from their homes rather than relocate, and considerably further on a weekly basis. This indicates that the construction workforce would likely come from farther than 20 miles from the Project site. Elsewhere, the AFC states that approximately 60 percent of the workforce is expected to be hired from within Kern County but that it is possible that some portion of the labor force will be drawn from Los Angeles County. (AFC, pp. 5.8-3, -16 and -18.) In addition, HECA has recently signed a project labor agreement ("PLA")[14] with the National Building and Construction Trades Department, the State Building and Construction Trades Council of California, and the Kern, Inyo, and Mono Counties Building and Construction Trades Council. Thus, some of the construction workforce may come from Inyo and Mono Counties. The southern border of Mono County is more than 150 miles from the Project site.

a) Please provide a copy of the PLA and/or indicate whether the PLA contains a breakdown for the origin of the construction workforce by county.

b) Please provide a breakdown of the available construction labor workforce by county.

c) Please identify typical travel distances for the construction workforce by county.

d) Please discuss whether you anticipate that construction workers would commute from their residence on a daily or weekly basis or seek lodging closer to the Project site.

e) Please revise emission estimates for worker vehicle travel during Project construction according to your responses above.

26. The AFC, p. 5.8-16, states that an estimated 60 percent of non-labor construction cost is anticipated to be spent within Kern County on materials and supplies. The remaining materials (comprising approximately 40 percent of non-labor cost), including the turbines, would be purchased outside Kern County.

a) Please specify whether the "remaining materials" (comprising approximately 40 percent of non-labor cost) would be transported to Bakersfield via rail and then reloaded onto trucks or whether these materials would be transported to the site via truck from their point of origin.

[14] Hydrogen Energy California, Announcing Project Labor Agreement for HECA Project, May 31, 2012; http://hydrogenenergycalifornia.com/uncategorized/announcing-project-labor-agreement-for-heca-project.

b) Please identify the quantities and source(s) of fill materials including their distance to the Project site.

c) Please quantify the number of truck trips required to transport materials and fill that would originate outside of Kern County.

d) Please revise emission estimates for off-site delivery/import fill truck travel during Project construction according to your responses above.

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 Requests:

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/m^2") 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?

    b) Please revise your estimates for fugitive dust emissions from public paved roads based on an appropriate silt loading factor (recommended site-specific value or ubiquitous baseline value of 0.2 g/m2 recommended by EPA for roads with 500-5,000 average daily trips) and appropriate average vehicle weight on the roads accessing the site.

28. The AFC estimates emissions from material handling and bulldozing/earthclearing activities based on 500,000 cubic yards of fill material. Elsewhere, the AFC states that preliminary grading plans indicate that approximately 1.1 million cubic yards of soil would be derived from off-site sources. (AFC, p. 5.9-14.)

    a) Please provide the preliminary grading plan for the Project.

    b) Please discuss this discrepancy between the amount of fill assumed to estimate fugitive dust emissions from dirt piling and material handling of 500,000 cubic yards and the amount of fill derived from off-site sources of 1.1 million cubic yards indicated by the preliminary grading plan.

    c) Please revise your estimates of fugitive dust emissions from material handling and bulldozing/earthclearing activities if indicated.

29. For estimating fugitive dust emissions from dirt piling or material handling for both the excavated soil (850,000 cubic yards) and imported fill (500,000 cubic yards), the AFC assumes a moisture content of 19% based on the average of soil borings taken at five feet depth. The AFC uses the same moisture content to estimate fugitive dust emissions from bulldozing/earth clearing activities. (AFC, Appx. E-2, p. 36.) The higher the assumed moisture content, the lower the estimated emissions. A moisture content of 19% based on the average of soil borings at five feet does not appear to be a reasonably conservative assumption for the soil handled during these activities for a number of reasons.

30. Import fill material, depending on its origin, may have considerably lower moisture content than on-site soils. Please identify the likely origin of the fill material and provide an appropriate moisture content for the 500,000 cubic yards of fill material that would be required. Please document your assumptions.

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.

32. Please revise your estimates of fugitive dust emissions from dirt piling or material handling for both the excavated soil and imported fill based on your responses above.

33. The AFC assumes a control efficiency of 67% for fugitive dust emissions from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and 98% for truck travel in soil import areas. (AFC, Appx. E-2, pp. 37-38.)These control efficiencies were derived by combining control efficiencies of two measures, watering and reducing traffic speed to 15 miles per hour ("mph"), for unpaved roads (45% and 40%, respectively) and soil import areas (85% and 70%, respectively) based on control efficiencies established by the South Coast Air Quality Management ("SCAQMD") in their 1993 California Environmental Quality Act ("CEQA") Air Quality Handbook. (AFC, Appx. E-2, p. 37, Footnote 1.) There are a number of problems with the AFC's approach.

First, the information in the SCAQMD's 1993 CEQA Air Quality Handbook relied upon by the AFC has been superseded. The agency is in the process of updating its CEQA guidelines and has published updated fugitive dust emission factors specific for each construction activity and mitigation measure in April of 2007.[15]

Second, the use of a combined control efficiency for dirt piling/material handling and storage piles that accounts for the effects of limiting traffic speed on site is nonsensical.

Third, the equation for grading emissions incorporates the speed of the grader. Here, the AFC assumes a travel speed of 4 mph. Assuming additional control from reducing traffic speed to 15 mph double-counts this measure and, thus, underestimates emissions.

Fourth, the assumption of a 19% soil moisture content inherently assumes control and additional watering would likely turn the site into a mud bath. Assuming additional control through watering double-counts this measure and, thus, underestimates emissions.

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[15] http://www.aqmd.gov/CEQA/handbook/mitigation/fugitive/MM_fugitive.html.

Fifth, the AC's assumption of the upper range of the recommended control efficiencies for the areas where soil will be imported because "extra care will be taken to keep the area watered and speeds extremely low" is not reflected in the proposed construction mitigation measures and is therefore unsupported.

Data Requests:

34. Please provide a list of control efficiencies for each category of activities taking into account the above discussion. Please justify and document your assumptions.

    a) Please revise the proposed mitigation measures for fugitive dust control during construction to account for any assumptions inherent in the assumed control efficiencies.

    b) Please revise control efficiencies for fugitive dust emissions from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and in soil import areas taking care to avoid double-counting and applying control efficiencies to the applicable source of fugitive dust.

35. Please revise your estimates for fugitive dust from dirt piling/material handling, grading, bulldozing/earthclearing, storage piles, and truck travel on unpaved roads and in soil import areas based on revised assumptions and control efficiencies.

Background: CONSTRUCTION MITIGATION MEASURES

The AFC, Table 5.1-25, p. 5.1-100, shows that Project construction would contribute substantially to existing exceedances of short-term and annual ambient air quality standards for particulate matter equal to or smaller than 10 micrometers ("PM10") and 2.5 micrometers ("PM2.5"). To provide mitigation for these impacts, the AFC states that the Project will implement a rigorous mitigation program to minimize fugitive dust and construction equipment exhaust and "will implement all of the SJVAPCD and CEC recommended mitigation measures … to control emissions during the construction phase of the Project from both fugitive dust and equipment combustion exhaust when feasible." The AFC lists eight mitigation measures for fugitive dust control (AIR-1) and four mitigation measures to control exhaust emissions from the diesel heavy equipment used during construction (AIR-2). (AFC, p. 5.1-57.) These mitigation measures are not sufficient to reduce the Project's impacts on air quality during construction to the extent feasible, as required by CEQA. Additional mitigation is feasible and should be required.

Data Requests:

36. The qualifier "when feasible" in the AFC's proposed mitigation measures makes them not enforceable. Please indicate whether the Applicant is willing to accept compliance with the proposed mitigation measures without this qualifier.

37. Additional mitigation measures are feasible. Please indicate whether the Applicant would be willing to accept the following mitigation measures as conditions of certification.

    a) Require a construction mitigation manager.

    b) EPA in its scoping comments for the Project recommended a number of mitigation measures that were not incorporated and/or are more stringent than those proposed by the AFC:[16]

        i. To reduce emissions of diesel particulate matter, hydrocarbons, and NOx associated with construction activities, EPA recommended the following with regard to all construction-related engines:

        - Minimize use, trips, and unnecessary idling of heavy equipment.

        - Maintain and tune engines per manufacturer's specifications to perform at EPA certification levels, where applicable, and to perform at verified standards applicable to retrofit technologies. Employ periodic, unscheduled inspections to limit unnecessary idling and to ensure that construction equipment is properly maintained, tuned, and modified consistent with established specifications. The California Air Resources Board has a number of mobile source anti-idling requirements which could be employed. See their website at: http://www.arb.ca.gov/msprog/truck-idling/truck-idling.htm.

        - Prohibit any tampering with engines and require continuing adherence to manufacturer's recommendations.

[16] *See* Kathleen M. Goforth, U.S. Environmental Protection Agency, Region IX, Letter to R. Paul Detwiler, U.S. Department of Energy, National Energy Technology Laboratory, Re: Scoping Comments for the Hydrogen Energy California's Integrated Gasification Combined Cycle Project, Kern County, May 28, 2010; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/others/2010-05-28_US_EPA_Comments_on_SA-DEIS_TN-57034.PDF.

- If practicable, lease new, clean equipment meeting the most stringent of applicable Federal or State Standards.

- In general, commit to the best available emissions control technology. Tier 4 engines should be used for project construction equipment to the maximum extent feasible. Lacking availability of non-road construction equipment that meets Tier 4 engine standards, DOE should commit to using the best available emissions control technologies on all equipment.

- Include all available mitigation measures to reduce greenhouse gas emissions.

- Utilize EPA-registered particulate traps and other appropriate controls where suitable to reduce emissions of diesel particulate matter and other pollutants at the construction site.

- Include control devices to reduce air emissions. The determination of which equipment is suitable for control devices should be made by an independent Licensed Mechanical Engineer. Equipment suitable for control devices may include drilling equipment, generators, compressors, graders, bulldozers, and dump trucks.

ii. To reduce fugitive dust emissions during construction, the EPA recommended the following measures in addition to the SJVAPCD-recommended mitigation measures:

- Stabilize open storage piles and disturbed areas by covering and/or applying water or a non-toxic soil stabilizer or dust palliative where appropriate, to both inactive and active sites, during workdays, weekends, holidays, and windy conditions.

- Install wind fencing and phase grading operations where appropriate, and operate water trucks for surface stabilization under windy conditions.

- When hauling material and operating non-earthmoving equipment, prevent spillage and limit speeds to 15 miles per hour (mph). Limit speed of earth-moving equipment to 10 mph.

- Cover vehicles hauling soil or other loose materials with tarp or other means.
- Sweep adjacent paved streets with water sweepers in the event soil materials are carried onto them.
- Reclaim and revegetate disturbed areas as soon as practicable after completion of activity at each site.

Background: SUPPORT FOR OPERATIONAL EMISSION ESTIMATES

The AFC relies on a number of unsupported assumptions and emission factors for its estimates of Project operational emissions of criteria pollutants and TACs/HAPs. Without adequate documentation, *e.g.,* the underlying vendor guarantees or other information such as stack tests, studies, etc., these assumptions and emission factors are unsupported and the public cannot meaningfully comment on their appropriateness.

Data Requests:

38. Please provide support for all assumptions for estimating Project operational emissions, including, but not limited to:

    a) Support for molar flow rates for exhaust gases from the heat recovery steam generator ("HRSG"), coal dryer stack, CO_2 vent, and Rectisol flare. (AFC, Appx. E-3, pp. 3-4, 6, and 12-13.)

    b) Support for emission factors, pollutant concentrations in exhaust gas, duration of various startup/shutdown phases, and other information "provided by MHI" used to estimate criteria pollutant emissions from the HRSG and coal dryer during normal operations and startup and shutdown. (AFC, Appx. E-3, pp. 3-6.)

    c) Support for emission factors for "similar equipment from previous project" used to estimate PM10/PM2.5 and VOC emissions from the auxiliary boiler. (AFC, Appx. E-3, p. 7.)

    d) Support for maximum short-term total sulfur content of 12.65 ppmv in pipeline natural gas used for estimating sulfur dioxide ("SO_2") emissions from the auxiliary boiler. (AFC, Appx. E-3, p. 7.)

    e) Support for emission factors used for estimating nitrogen oxides ("NOx") and carbon monoxide ("CO") emissions from the tail gas thermal oxidizer "based on previous project." (AFC, Appx. E-3, p. 8.)

f) Support for emission factor used for estimating SO_2 emissions from the tail gas thermal oxidizer "assuming an allowance of 2 lb/hr SO_2 emission to account for sulfur in the various vent streams plus fuel." (AFC, Appx. E-3, p. 8.)

g) The "plant performance study" used to support short term emission rates of from CO_2 vent and support for hydrogen sulfide ("H_2S"), carbonyl sulfide ("COS"), CO, and VOC concentrations in vent gas. (AFC, Appx. E-3, p. 10.)

h) Support for emission factors based on "supplier data" used to estimate NOx, CO, and PM10/PM2.5 for flares. (AFC, Appx. E-3, p. 11.)

i) Support for 99% VOC destruction assumed for combustion of typical natural gas in flare. (AFC, Appx. E-3, p. 11.)

j) Support for emission factors for flares "Based on Startup/Shutdown Procedures provided by MHI for the PurGen One Project." (AFC, Appx. E-3, p. 12.)

k) Support for 99.6% sulfur removal efficiency for caustic scrubber. (AFC, Appx. E-3, p. 12.)

l) Support for SO_2 concentration in vent gas of 50 ppmv used to determine SO_2 emissions from the Rectisol flare. (AFC, Appx. E-3, p. 13.)

m) Support for sulfur concentration in pipeline natural gas used to estimate SO_2 emissions from the ammonia synthesis plant startup heater. (AFC, p. 20.)

n) Support for emission factors for "similar equipment from previous project" used to estimate PM10/PM2.5 and VOC emissions from the ammonia synthesis plant startup heater. (AFC, p. 20.)

o) The "[t]echnical proposal provided by Urea Casale for the SCS PurGen One project" used to derive NH_3 emission factors for the urea HP and LP absorber. (AFC, Appx. E-3, p. 20.)

p) Support for the "[r]eference plant information provided by Sandvik Fellbach for the SCS PurGen One project" used to derive ammonia ("NH_3") and urea dust particulate matter emission factors from urea pastillation. (AFC, Appx. E-3, p. 20.)

q) Support for NOx concentration in vent gas of 15 ppmv "based on Uhde EnviNOx system" and 50% NO_2/NOx in stack-ratio used for modeling. (AFC, Appx. E-3, p. 20.)

r) Vendor guarantee for PM emission rate used to calculate PM emissions from ammonium nitrate plant. (AFC, Appx. E-3, p. 20.)

s) Support for emission factors and control efficiency for leak detection and repair ("LDAR") program used to estimate fugitive emissions of CO_2, methane ("CH_4"), CO, H_2S, NH_3, COS, methanol ("CH_3OH"), propene ("C_3H_6"), and hydrogen cyanide ("HCN") from various process areas. (AFC, Appx. E-3, p. 23.)

t) Support for emission factors used to estimate TAC/HAP emissions from the combustion turbine generator ("CTG")/HRSG and coal dryer stacks "taken from Wabash River test data and the National Energy Technology Laboratory, U.S. Dept of Energy, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002. (AFC, Appx. M, p. 2.) Please provide Wabash River test data and identify the source for each emission factor used to calculate TAC/HAP emissions for the Project. Please discuss why Wabash River test data are deemed representative for the Project's CTG/HRSG and coal dryer stack.

u) Support for the assumption that 85% of the HRSG exhaust gas would be exhausted through the HRSG exhaust and 15% through the coal dryer exhaust under normal operations. (AFC, Appx. M, p. 2.)

v) Support for the assumption of 0.09 parts per million by weight ("ppmw") mercury in coal. (AFC, Appx. M, p. 2.)

w) Support for the assumption that 5.5% of the mercury concentration in coal is volatilized. (AFC, Appx. M, p. 2.)

x) Support for the coal dryer mercury control efficiency of 80% and the control efficiency of the mercury cleanup in syngas of 96%. (AFC, Appx. M, p. 2.)

y) Support for emission factors used to estimate arsenic, fluoride, manganese, and selenium emissions from cooling towers based on "average of analytical test results" from "Fruit Growers Laboratory" and "DWR". (AFC, Appx. M, p. 3.) Please provide these analytical test results and discuss why these emissions are deemed representative for the Project.

z) Support for the assumption that copper emissions from the cooling towers would be "one-half of stated detection limit." (AFC, Appx. M, p. 3.)

aa) Support for emission factors used to estimate emissions of ammonia from manufacturing complex based on "reference plant information." (AFC, Appx. M, p. 13.)

Background: EMISSIONS ASSOCIATED WITH RAIL TRANSPORTATION

The diesel-powered rail locomotives that would be used for transporting coal from New Mexico to California and other materials to and from the Project site can have substantial emissions. In addition, the transportation of coal results in losses of coal dust during transportation in uncovered rail cars and fugitive dust emissions from trucks and during loading/unloading activities. The AFC fails to provide adequate information for rail transport and appears to substantially underestimate both sources of emissions, combustion and fugitive dust, associated with coal transportation.

Data Requests:

39. The AFC assumes that the Project would use line-haul and switching engines that meet EPA Tier 3 emission standards for new engines to estimate on-site and off-site combustion emissions from locomotives delivering feedstock and products to and from the site or the Wasco transloading facility. (AFC, Appx. E-3, p. 33, and Appx. E-5, p. 4.). Since these locomotives would not be owned or operated by HECA but rather by commercial rail freight carriers, the assumption that all engines would comply with EPA Tier 3 emission standards is unrealistic. Further, the AFC's assumption for the engine size of the on-site switcher locomotive of 260 horsepower appears to be too small.

    a) Please identify the rail carrier(s) for each material transported by rail and provide their respective locomotive fleet composition and respective emission factors. Please provide adequate support.

    b) Please provide emission estimates based on either the engine fleet(s) operated by the respective rail carrier(s) or based on average fleet average emission factors for locomotives established by EPA in its April 2009 document *Emission Factors for Locomotives* (EPA-42-F-025).

    c) Please provide manufacturer data for the on-site switcher locomotive and confirm the horsepower rating or provide updated emission estimates for

40. The AFC, p. 2-22, states that under Alternative 1 (train transportation), the Project site would be equipped with a rail unloading and transfer system and indicates that the transfer conveyor would be fully enclosed. However, it is unclear whether unloading of coal from railcars onto the transfer conveyor would also be fully enclosed.

a) Please discuss railcar unloading at the Project site under Alternative 1 and clarify whether railcar unloading would be fully enclosed. If not, please indicate whether the Applicant would be willing to fully enclose railcar unloading.

b) If railcar unloading would not be fully enclosed, please provide an estimate of fugitive dust emissions from railcar unloading onto the enclosed transfer conveyor.

41. The AFC presents onsite and offsite transportation emissions associated with Alternative 1 (train transportation) and Alternative 2 (truck transportation) in Tables 5.1-20 and 5.1-37, and Appendix E-5 and E-12, respectively. These emission estimates do not include offsite material handling emissions, *e.g.*, from transfer of coal from railcars onto trucks at the Wasco transloading facility under Alternative 2. Please estimate these emissions.

42. Coal dust can become airborne in particle sizes smaller than 500 microns and is notoriously hard to control. A thick layer of black coal dust can often be observed along the railroad right-of-way and in between the tracks and frequently dust plumes are seen rising from rail cars. Studies conducted by the Burlington Northern Santa Fe ("BNSF") Railway indicate that each uncovered loaded rail car loses between 500 pounds and a ton of coal dust in transit.[17] Another study on a West Virginia rail line showed loss of coal dust of up to a pound of coal per rail car per mile.[18] This loss occurs throughout the entire transport, as the mechanical fracturing of the coal continuously produces fugitive dust as the coal settles. There are even substantial coal dust emissions on the return trip, as the "empty" cars actually contain a significant quantity of fine particles known as "carry back."[19] Based on this information, coal dust losses for the Project can be estimated at about 4,500

[17] BNSF, Coal Dust Frequently Asked Questions, http://www.coaltrainfacts.org/bnsf-coal-dust-frequently-asked-questions.

[18] E.M. Calvin, G.D. Emmett, J.E. Williams, A Rail Emission Study: Fugitive Coal Dust Assessment and Mitigation, 1996; http://www.powerpastcoal.org/wp-content/uploads/2011/08/A-RAIL-EMISSION-STUDY-FUGITIVE-COAL-DUST-ASSESSMENT-AND-MITIGATION.pdf.

[19] Connell Hatch, Coal Loss Literature Review, Coal Loss Management Project, Queensland Rail, January 11, 2008; http://www.qrnational.com.au/InfrastructureProjects/Rail%20Network/Coal_Loss_Management_Project_-_Interim_Report_-_Part_2.pdf.

tons/year, a fraction of which is PM10 and PM2.5.[20] The AFC does not estimate PM10 and PM2.5 emissions from fugitive coal dust associated with rail transport.

a) Please provide estimates for PM10/PM2.5 emissions associated with fugitive coal dust losses from rail car transport.

b) Coal dust suppression measures for rail cars exist have been used successfully. Effective measures include covering the rail cars with tarp and application of a surfactant, *e.g.,* latex coating. Would the Applicant be willing to require the coal supplier to cover rail cars or apply dust suppressants?

Background: OFFSITE EMISSIONS FROM MATERIALS TRANSPORTATION VIA TRUCK

The offsite emissions from fuel, product, and waste hauling for the Project are substantial. In response to a data request by CEC staff for the prior configuration of the Project—inquiring whether the Applicant would be willing to stipulate to contracting for only new trucks for fuel delivery at the time of starting operations and maintaining a maximum average fleet age, or some other measures to mitigate this large emissions source—the Applicant indicated that they are "willing to commit to only employing trucks that meet or exceed the 2010 heavy diesel emission standards."[21] This response is ambiguous and the current AFC is silent on such a condition as potential mitigation.

Data Requests:

43. Please identify the percentage of trucks that would be owned by or under control of the Applicant for each fuel, product, waste, and other material delivery and the percentage of truck trips that would be contracted out where the Applicant would have no control over the emission standards of the respective truck fleet.

44. Please indicate whether the Applicant would be willing to accept a condition of certification stipulating that it purchase only new trucks for materials delivery (at the time of starting operations) and maintain a maximum average fleet age (please identify).

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[20] (1 lb coal dust loss/rail car/mile) × (13,034 rail cars/year) × (700 miles from Grants, NM, to Bakersfield, CA) / (2000 lb/ton) = 4,561.9 ton coal dust loss/year)

[21] 08-AFC-08, November 11, 2009 Responses to CEC Data Requests Set One – Nos. 1 through 132, #27.

45. Please indicate whether the Applicant would be willing to explore additional potential mitigation for emissions from haul contractor trucks over whose fleet the Applicant would have no control.

Background: EMISSIONS FROM COMBUSTION TURBINE GENERATOR/HEAT RECOVERY GENERATOR

Based on a top-down analysis, the AFC determines Best Available Control Technology ("BACT") for NOx emissions from the Project's combustion turbine generator/heat recovery steam generator ("CTG/HRSG") as diluent injection in the combustion turbine and installation of a selective catalytic reduction ("SCR") system for post-combustion control with BACT emission limits of 2.5 ppm NOx at 15% oxygen ("O_2") when firing hydrogen-rich syngas and 4 ppm at 15% O_2 when firing natural gas, both on a 3-hour rolling average. For carbon monoxide ("CO") emissions, the AFC proposes good combustion practice and a CO catalyst as BACT with emission limits of 3 ppm CO at 15% O_2 on hydrogen-rich syngas and 5 ppm CO at 15% O_2 on natural gas, both on a rolling 3-hour average. (AFC, Appx. E-11, pp. 4, 23-24, and 26-28.)

The AFC "anticipates" that this combination of control technologies would achieve the proposed BACT emission limits. (*Ibid.*) However, it is unclear whether the Project would indeed be able to comply with the proposed emission limits as information on emissions associated with the proposed technology is scarce to non-existent. The proposed technology has not been installed in the United States and the Applicant did not supply any data or information based on experienced gathered at MHI's 250-MW Nakoso, Japan, facility. The AFC's BACT analysis identifies neither the SCR and CO catalyst control efficiency nor the uncontrolled CO and NOx emission rates from the CTG/HRSG. (Portions of the BACT analysis that contain information regarding the uncontrolled emission rates are blacked out; *see* AFC, Appx. E-11, pp. 21 and 26.). The Applicant's legal counsel indicated that this information is considered confidential business information and cannot be released.[22] Instead, the CEC and the public are expected to accept the proposed emission limits at face value.

Data Request:

46. Please provide either a) information on uncontrolled CO and NOx emissions rates from the CTG/HRSG or b) manufacturer guarantees indicating that the proposed BACT emission limits can be achieved with the proposed combination of control technologies.

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[22] Phone conversation with Michael Carroll, Latham & Watkins, July 20, 2012.

Background: ALTERNATIVE FUELS/FEEDSTOCKS OR FEEDSTOCK BLENDS AS BACT FOR TURBINES

The Project would result in substantial emissions of criteria pollutants, TACs/HAPs, and greenhouse gases and contribute to the region's already severely impaired air quality and global climate change. These emissions could be reduced by using alternative fuels/feedstocks such as natural gas or biomass[23] instead of the proposed solid carbon feedstocks (coal and petcoke) or by reducing or eliminating the amount of coal as feedstock. The AFC's BACT analysis for the Project does not adequately discuss the use of alternative fuels/feedstocks.

Data Requests:

47. The AFC concludes that the use of natural gas would not meet the Project's design and purpose which it narrowly defines as a) the use of solid carbon feedstocks (coal and petcoke) to produce low-emission electricity; b) the generation of hydrogen for low-carbon electricity and nitrogen-based products; and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery. (AFC, Appx. E-11, p. 11.)

    a) The first stated objective for the Project, to use solid-carbon feedstocks relies on the invalid circular argument that the objective of the Project is to use coal and petcoke. The AFC supports the choice of these solid fuel feedstocks because a) they are historically cheaper (per British thermal unit) than natural gas; b) they are more widely available in the United States than natural gas; and c) the use of natural gas would not qualify for funding or meet the objectives of DOE's Clean Coal Power Initiative. (AFC, Appx. E-11, p. 13.)

        i. In recent years and particularly the last year, prices for natural gas have decreased dramatically with prices at the Henry Hub falling from between \$4 to \$8 per million Btu ("MMBtu") with spikes up to \$15 before 2010 to consistently between \$2 to 3 per million 2012.[24] Please provide a discussion of natural gas vs. coal/petcoke prices (as delivered) and their impact on operating costs.

        ii. Please discuss why the qualification for funding or meeting the objectives of DOE's Clean Power Initiative qualifies as a project

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[23] *See*, for example, Henry A. Long, III and Ting Wang, Case Studies for Biomass/Coal Co-Gasification in IGCC Applications, Proceedings of ASME Turbo Expo 2011, Vancouver, Canada, June 6-10, 2011; http://eccc.uno.edu/pdf/Long-Wang-GT2011-45512.pdf.

[24] Natural Gas Spot Prices at the Henry Hub 2012; http://www.neo.ne.gov/statshtml/124.htm.

objective that precludes the use of cleaner feedstocks and/or technologies.

b) The latter two stated objectives (b and c) for the Project could also be achieved by the combustion of natural gas or the combustion or gasification of biomass or biomass blends with solid fossil feedstocks.

i. Please indicate whether you acknowledge that b) the generation of low-carbon electricity and nitrogen-based products and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery products could also be achieved by a natural gas-fired combined-cycle plant.

ii. Please indicate whether you acknowledge that b) the generation of low-carbon electricity and nitrogen-based products and c) the capture of CO_2 and transporting CO_2 for use in enhanced oil recovery products could also be achieved by combustion or gasification of biomass or biomass blends with solid fossil feedstocks.

48. The AFC concludes that use of natural gas would require substantial re-design of the facility and lists a number of Project units that would be affected. Please discuss how each of these units would be affected if using natural gas.

49. The AFC does not discuss the use of biomass as an alternative feedstock or the use of feedstock blends with different percentages than proposed, for example by reducing or eliminating the amount of fuel in the feedstock blend (*e.g.,* 50% coal/50% petcoke, 25% coal/75% petcoke, or 100% petcoke) or substituting biomass for a portion of the feedstock blend. Please discuss whether these alternative fuels or fuel blends would require substantial re-design of the facility and indicate which process units would be affected and how the design would have to be changed.

Background: NOx EMISSIONS FROM AUXILIARY BOILER

The Project would use a natural gas-fired auxiliary boiler equipped with low-NOx burners and a selective catalytic reduction ("SCR") system to provide steam for pre-start equipment warm-up and other miscellaneous purposes when steam from the gasification block or HRSG is not available. The AFC determined a NOx BACT emission limit for the auxiliary boiler of 0.006 pounds per million British thermal units ("lb/MMBtu") based on a NOx concentration of 5 parts per million by volume, dry ("ppmvd") at 3% oxygen. The AFC's emission estimates assume that NOx concentrations in the boiler exhaust would not exceed this limit regardless of operating conditions. (AFC, Appx. E-3, p. 7.)

Because the SCR catalyst must reach a certain temperature to effectively reduce NOx in the exhaust gas, NOx emissions from the auxiliary boiler may be underestimated during periods when the exhaust gas temperature is below the minimum needed for effective SCR, such as during the commissioning period and part of the startup period of the auxiliary boiler. The majority of boiler operations are expected to be at low load, likely below the minimum needed for effective SCR control.

Data Requests:

50. Please provide emission factors for NOx emissions from the auxiliary boiler during initial auxiliary boiler commissioning and during startup while the SCR catalyst has not reached its optimal operating temperature.

51. Please provide estimates for short-term NOx emissions during the initial auxiliary boiler commissioning period.

52. Please provide updated emission estimates for NOx emissions from the auxiliary boiler accounting for higher NOx emissions while the SCR catalyst has not reached operating temperature and during shutdown.

Background: VOC AND PM10/PM2.5 EMISSIONS FROM TAIL GAS THERMAL OXIDIZER

The Project would operate a tail gas thermal oxidizer to safely dispose of a) tail gas from the sulfur recovery unit ("SRU") in the event of an emergency or upset, b) waste gas during SRU startups, and c) miscellaneous vent streams from the gasification area. The AFC estimates VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer while combusting these gas streams based on emission factors from EPA's AP-42, Chapter 1.4 for natural gas combustion. These calculations may underestimate VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer. The AFC provides no support for this assumption.

Data Requests:

53. Please discuss why the emission factors for VOC and PM10/PM2.5 provided in AP-42, Chapter 1.4, for natural gas combustion are deemed representative for combustion in the tail gas thermal oxidizer of a) SRU tail gas in the of an emergency or upset, b) waste gas during SRU startups, and c) miscellaneous vent streams from the gasification area.

54. If necessary, please provide revised emission factors and emission estimates for VOC and PM10/PM2.5 emissions from the tail gas thermal oxidizer.

Background: BACT FOR FLARES

The Project would operate three flares: a gasifier flare to dispose of gases during gasifier startup and unplanned power plant upsets or equipment failures; a flare in the sulfur recovery unit ("SRU") to dispose of gas emissions from the acid gas removal ("AGR") process during startup (after passing via a scrubber) or to oxidize releases during emergency or upset events; and a flare in the Rectisol area to dispose of low-temperature gas streams during startup, shutdown and unplanned upset and emergency events. (AFC, p. 5.1-20.) All three flares are proposed as conventional elevated flares with natural gas assist. (AFC, p. 2-38.) The AFC eliminates the use of enclosed ground flares due to not further specified concerns with reliability claiming that enclosed ground flares have never been installed on any IGCC plants and are considered unproven technology with an associated risk. (AFC, Appx. E-11, pp. 54 and 57.)

Enclosed ground-level flares are commonly specified as BACT to reduce emergency flaring emissions.[25] In a ground flare, the flare tip and combustion zone are enclosed within a refractory shell that is internally insulated and located at ground level. The gases are vented through an elevated stack. The shell reduces noise, luminosity and heat radiation, and perhaps most importantly, it protects the combustion zone from wind. (The Project is located in an area with high wind events.) Such shells also result in more stable combustion conditions for gases with lower heat content (such as the syngas produced at the Project) and therefore more effective flaring. Thus, ground level flares would reduce emissions compared to elevated flares proposed here.

Several recent IGCC facilities were designed with enclosed ground flares including the PureGen One facility in Linden, NJ[26] and the IGCC Unit B at the Curtis H. Stanton Energy Center near Orlando, FL[27]. Thus, it would appear that the use of ground flares rather than elevated flares is BACT.

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[25] Bay Area Air Quality Management District, Best Available Control Technology (BACT) Guideline, Refinery Flares, June 30, 1995: "Ground level flare, enclosed, steam- or air-assisted, w/ staged combustion; POC destruction efficiency >98.5%;" http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

[26] SCS Energy, PurGen One IGCC Facility, Linden, New Jersey, Preconstruction Permit & Operating Certificate Application, December 30, 2009; http://www.precaution.org/lib/purgen_air_permit_fnl.100127.pdf.

[27] Florida Department of Environmental Protection, OUC/Southern Power Company – Orlando Gasification, Curtis H. Stanton Energy Center, IGCC Unit B, PSD Permit No. PSD-FL-373,

Data Requests:

55. Please discuss in detail the reliability concerns and risks associated with using ground as opposed to elevated flares separately for each of the Project's three flares.

56. Please discuss why the use of enclosed ground flares is considered feasible for other IGCC facilities but not for HECA.

57. The Applicant initially considered the use of an enclosed ground flare for gasification block for the Project.[28] Please discuss the reasons for changing the design from a proposed ground flare for the gasifier block to an elevated flare.

58. Please discuss the feasibility of using an enclosed ground flare for routine periodic flaring and an elevated flare as an emergency backup.

Background: HAZARDOUS AIR POLLUTANT EMISSIONS FROM FLARES

Flares emit hazardous air pollutants ("HAPs") during both routine and non-routine operations from three sources: (1) pilot; (2) supplementary natural gas fuel; and (3) syngas and waste gases. The AFC estimates emissions of HAPs from flares during pilot operation and gasifier startup/shutdown based on emission factors from EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), Chapter 1.4, for natural gas-fired boilers. (AFC, Appx. M, pp. 6-8.) This assumes the behavior of a flare from a combustion standpoint is similar to a natural gas fired boiler, which is not the case. A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. In contrast, a flare has no combustion chamber and highly variable gas flow and composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler. Further, the flares would combust syngas and waste gases have a different composition than natural gas.

December 22, 2006; http://www.dep.state.fl.us/air/emission/construction/ouc_southern/373FPERMIT.pdf.

[28] Southern California Edison, Testimony in Support of Application for Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California IGCC with Carbon Capture and Storage, Before the Public Utilities Commission of the State of California, April 3, 2009, pp. 2-39 – 24-40; http://www3.sce.com/sscc/law/dis/dbattach7.nsf/0/2A85B596280D04328825758D0078A926/$FILE/A0904XXX+HECA+-+SCE+Testimony+in+Support+of+Application.pdf.

Data Requests:

59. Please explain why HAP emission factors determined for natural gas combustion in boilers are deemed representative for combustion of natural gas, syngas and waste gases in the Project's flares for both normal operating emissions from the pilot and during gasifier and Rectisol startup and shutdown.

60. Please provide conservative estimates for the concentration of HAPs in flared gases based on material balances for the Project's individual process units and experience at existing IGCC plants (*e.g.*, Puertollano, Spain, or Wabash River Generating Station, IN).

61. Did the Applicant inquire with MHI whether they have any experience with HAP emissions from flares at the Nakoso facility in Japan? If yes, please provide the response. If not, please inquire with Mitsubishi whether they have any data or other information available.

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 <u>and malfunction</u> 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

[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.

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.

Data Requests:

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.

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

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

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

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

Background: COOLING TOWER BACT ANALYSIS

The AFC concludes that BACT for the Project's cooling needs is the use of wet cooling towers over the use of air-cooled condensers mainly based on capital cost differential. This cost differential was determined in a cost-effectiveness analysis contained in a 2008 *Water Usage Minimization Study* for the Project's previously proposed configuration. (08-AFC-08, Appx. X, and AFC, Appx. E-11, p. 46.) The AFC's analysis is not adequately documented, outdated and flawed.

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[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.

67. The *Water Usage Minimization Study* highlights that Kern County is a very dusty area due the vast desert/farm lands and high winds, which will present problems with the wet cooling tower fill material due to fouling and result in mud buildup in the basin. Therefore, the study recommends installation of a less efficient film fill with larger openings in the wet cooling tower better suited to this environment. In addition, the use of brackish water in the cooling tower requires a decrease in the cycles of concentrations to prevent the solids in the circulating water from precipitating out. Further, the use of brackish water requires upgrading of the cooling tower materials to counter the effects of the corrosive brackish water.

a) Please discuss whether the proposed design of the cooling towers (circulation rate, makeup water, etc.) takes into account the above recommendations.

b) Please discuss how the dusty ambient air would affect the performance of an air-cooled condenser.

c) The AFC, Appx. E-11, p. 46, indicates that the Project would use high-efficiency drift eliminators with a drift rate of 0.0005%.

i. Please discuss how the above discussed problems with the dusty and windy environment (see 08 AFC-08, Appx. X) and using brackish water with high total dissolved solids ("TDS") content would affect the performance of the drift eliminators.

ii. Please provide a vendor guarantee for the Project's cooling towers guaranteeing a 0.0005% drift rate under the above discussed conditions.

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.

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 SO_2 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.

70. The AFC, Appx. E-11, p. 47, provides an estimate of total annualized costs for an air-cooled condenser of $213,900 per ton of particulate matter ("PM") controlled. HECA "believes that this high cost per ton of PM for using an ACC is cost prohibitive for the Project." Please identify the costs in US$ per ton of PM removed that would qualify as cost-effective to HECA.

71. The AFC's calculation assumes a cost differential for the air-cooled vs. the water-cooled condenser of $37 million. This cost differential is based on the assumption that fresh water with five cycles of concentration is used in the wet-cooled condenser. Here, the Project would use brackish water with only three cycles of concentration, which would reduce the cost-differential between the by $5 million. (08-AFC-08, Appx. X, Table 9, p. 12.) Please revise

the cost-effectiveness analysis accounting for the use of brackish water (three cycles of concentration) instead of fresh water (five cycles of concentration).

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

    a) Please document the basis for the assumed 7 percent interest.

    b) Please discuss why the assumed life is only 20 years instead of the Project's design operating life of 25 years (AFC, p. 3-1).

    c) Please discuss the design operating life of an air-cooled condenser and its potential life expectancy.

    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.

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.

Background: EMISSIONS FROM THE COOLING TOWERS

Emissions of criteria pollutants and TACs/HAPs from the Project's three cooling towers appear to be underestimated.

Data Requests:

74. The AFC, p. 2-37, states that the power block cooling tower would use a chemical feed system which will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Chemicals would include sulfuric acid, polyacrylate solution, and sodium hypochlorite.

    a) Please discuss whether the Project's process and air separation unit cooling towers would use the same supply water conditioning chemicals.

    b) Please estimate criteria pollutant and TAC/HAP emissions associated with the use of these chemicals, including emissions of sulfuric acid and chloroform, from the Project's cooling towers.

75. The AFC's estimate of TAC/HAP emissions from the Project's three cooling towers does not include zinc. Please provide an estimate of zinc emissions from the cooling towers.

Background: FUGITIVE EMISSIONS FROM ORGANIC LIQUID STORAGE TANKS, PIPING AND COMPONENTS

Fugitive emissions from the Project would include standing and working losses from organic liquid storage tanks and due to leaks in piping and components, such as valves, pump seals, compressor seals, flanges, pressure relief valves, connectors, open-ended lines, sampling connections, etc. These emissions include both VOCs and TACs/HAPs. The AFC presents a summary of fugitive VOC emissions in Appendix E-3, p. 23, and estimates for TAC/HAP emissions from piping and components in Appendix M, pp. 17-25. These emission estimates are inadequately documented and appear to be substantially underestimated.

Data Requests:

76. The AFC's estimates do not include fugitive VOC or TAC/HAP emissions from organic liquid storage tanks. Please identify and provide the capacity and turnover rate for all of the Project's organic liquid storage tanks, such as the 300,000-gallon methanol storage tank, diesel storage tanks, and solvent storage tanks, and provide estimates for fugitive emissions from these sources. Please include roof landing losses. Please indicate if tanks would be equipped with a tank vent oxidizer.

77. Additional information is required to assess the adequacy of the AFC's component count, provided in Appendix M, p. 19, and its estimates of fugitive emission from Project equipment.

    a) Please identify all Project equipment from which fugitive emissions could occur including traditional components such as valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines as well as nontraditional component types such as screwed fittings, liquid relief valves, agitators, heat exchanger heads, site glasses, bolted manways/hatches, blind flanges, caps/plugs, connectors, compression, fittings, and metal-to-metal seals. The latter have not traditionally been treated as sources of equipment leaks but recent scientific studies have identified them as such.32 Please break out the count by process area and component types.

b) The AFC, Appx. M, p. 19, identifies the following components for fugitive equipment leaks for process areas 11 (sulfur) and process unit 12 (tail gas treating unit process gas): 37 heavy-liquid valves and 2 heavy-liquid pumps (process area 11) and 53 gas valves and 203 connectors (process area 12). Previously, the Applicant provided the following component count for fugitive equipment leaks for these process areas: 72 heavy-liquid valves and 4 heavy-liquid pumps (process area 11) and 72 gas valves and 290 connectors (process area 12). Please discuss why the component counts of process areas 11 and 12 are considerably lower than previously assumed.

c) Please revise the emission estimates for VOC and TACs/HAPs if any additional components are identified.

78. The AFC's estimates for fugitive VOC emissions from piping and components appear not to include the wastewater treatment area. Please provide estimates for fugitive emissions from these sources.

79. The AFC, p. 5.6-11, estimates emissions of VOCs and TACs/HAPs based on guidance by the SJVAPCD in its memo *Procedures for Quantifying VOC Emissions at Petroleum and Synthetic Organic Chemicals manufacturing Industry (SOCMI)*, dated 2005, and using emission factors from the EPA document *Protocol for Equipment Leak Emission Estimates*, dated 1995. This document provides emission factors for four industry types: a) oil and gas production operations, b) refineries, c) marketing terminals and d) synthetic organic chemical manufacturing ("SOCMI"). The AFC finds, based on EPA's criteria for determining the appropriateness of emission factors, that the Project's processes are most similar to a SOCMI plant and therefore used SOCMI emission factors. (AFC, p. 5.6-11.) The AFC provides no justification for or discussion of this finding. Additionally, the emission factors provided in the EPA document are considerably lower for SOCMI facilities than for refineries.

a) Please provide a step-by-step discussion of the EPA's criteria for determining the appropriateness of emission factors for the Project's processes based on 1) process design, 2) process operation parameters, 3) types of equipment used, and 4) types of material handled.

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[32] Texas Commission on Environmental Quality, Emissions Inventory Guidelines, Technical Supplement 3: Equipment Leak Fugitives, TCEQ Publication RG-360, January 2006; http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/rg/rg360/rg-360-05/techsupp_3.pdf.

b) Please discuss why the same industry type should be applicable for equipment in the gasification block and the manufacturing complex.

80. Please revise the operational health risk assessment for the Project reflecting any revisions to emission factors for TAC/HAP and emissions from additional sources (piping and components in wastewater treatment area and other process areas, organic liquid storage tanks).

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.

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: SO_2 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.

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.

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

HAZARDOUS MATERIALS

Background: OFFSITE CONSEQUENCE ANALYSIS FOR ANHYDROUS AMMONIA

The Project would produce up to 2,000 stpd anhydrous ammonia and store approximately 3.8 million gallons on site in two double-walled cylindrical steel tanks. In addition to on-site use for selective catalytic reduction, anhydrous ammonia is the basis for the Project's fertilizer production of urea and ammonium nitrate. Anhydrous ammonia would also be sold wholesale to commercial users. (AFC, p. 2-20 and Appx. K, pp. K-5/K-6.) Ammonia is a hazardous material and has a specified toxic endpoint value of 0.14 mg/L, which is approximately equal to 200 parts per million ("ppm"). In its anhydrous form, ammonia is a gas which is maintained in a liquid state through pressurization of the handling and storage systems. When spilled, anhydrous ammonia will vaporize, releasing ammonia vapors to the surrounding atmosphere and potentially resulting in hazardous ambient concentrations in the vicinity of the release. The impact of an accidental release of anhydrous ammonia generated and used by the Project would depend upon the location of the release relative to the public. The AFC's discussion is accidental ammonia releases is inadequate and not adequately supported.

Data Requests:

84. The AFC provides an off-site consequence analysis for the potential catastrophic failure of the entire 3.8 million gallons of aqueous ammonia in the storage tanks.

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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**.

a) Please provide the input/output files for the ALOHA 5.4 air dispersion modeling.

b) The AFC refers to "model results in Figure L-1, Aqueous Ammonia Area of Potential Impact from Worst-Case Scenario" but fails to provide this figure. (AFC, Appx. K, p. K-19.)

c) Please provide a copy of Figure L-1. Please discuss why the dispersion analysis does not account for prevailing wind direction. (*See* AFC, Appx. K, p. K-19.)

85. The transportation of ammonia, and any other hazardous material, poses a risk of exposure to the surrounding population due to an accidental release caused by a traffic accident involving the delivery vehicle. The possibility of accidental release during delivery depends upon the skill of the drivers, the type of vehicle used for transport, and the traffic conditions or road type. Because of the potential impact on the public, there are extensive regulatory programs in place in the United States and California to ensure safety during the transportation of hazardous materials, including the Federal Hazardous Materials Transportation Law (49 U.S.C. §5101 et seq.), the U.S. Department of Transportation Regulations (49 CFR Subpart H, §172-700), and California DMV Regulations on Hazardous Cargo (CCR, Vehicle Code, §34000). These regulations also address the driver's abilities and experience. Because of these regulations, CEC staff typically focuses on the potential for an incidence after the delivery vehicle has left the main highway due to the greater potential for accidents to occur on non-highway roads. The AFC does not provide a risk analysis for transportation of anhydrous ammonia resulting from a tanker accident on non-highway delivery routes.

a) Please identify the non-highway delivery routes for transportation of anhydrous ammonia to customers and identify all sensitive receptors (*e.g.*, residences, schools, places of worship, etc.) along these routes.

b) Please identify the maximum amount of anhydrous ammonia that could be sold directly to customers.

c) Please provide a risk analysis for transportation of anhydrous ammonia resulting from a delivery vehicle accident. Please consider the agricultural nature of the surrounding area and the likely presence of slow-moving and oversized agricultural vehicles.

POWER PLANT RELIABILITY

Background: RELIABILITY AND AVAILABILITY

The AFC states that the Mitsubishi Heavy Industries ("MHI") gasification technology for solid fuels has been demonstrated at commercial scale at the 250-MW integrated gasification combined cycle ("IGCC") Facility in Nakoso, Japan, which has been in operation since 2008. The AFC further states that the MHI gasification technology has been demonstrated on a variety of coal and other feedstocks in pilot facilities, demonstration plants and the commercial facility at Nakoso, Japan. (AFC, p. 2-74.) The AFC does not provide any information demonstrating MHI's experience with this technology or details about the 250-MW Nakoso facility and how they relate to the Project.

Data Requests:

86. Does the Nakoso IGCC facility employ a single- or double-walled gasifier?

87. Does the Nakoso IGCC facility have a backup gasifier?

88. The Nakoso IGCC facility is using an air-blown gasifier; in contrast, the Project would use oxygen-blown gasifier. Please discuss the net plant efficiency and reliability for the Nakoso IGCC facility. Please discuss how the different type of gasifier proposed for the Project would influence plant efficiency and reliability.

89. The Nakoso IGCC facility uses a modified MHI M7010DA gas turbine.[34] The Project would use an MHI 501 GAC combustion turbine. (AFC, p. 6-22.) Please discuss how these turbine designs affect performance.

90. MHI literature indicates that the Nakoso IGCC facility has experience gasifying a number of different coals but does not appear to have experience gasifying petcoke.[35] Please discuss any challenges associated with gasifying petcoke in the proposed gasifier.

91. Please demonstrate reliability for running the Project's gasification/power block 100% of the time with only two shutdowns per year, as proposed.

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[34] http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/4-gasifiers/4-1-2-5_mhi.html.

[35] Koichi Sakamoto, Mitsubishi Heavy Industries, Ltd., Commercialization of Mitsubishi IGCC/Gasification Technology, 2011 Gasification Technologies Conference, October 10, 2011; http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/pdfs/17SAKAMOTO.pdf.

92. Please provide any operational data, source tests, or other experience for the Nakoso IGCC facility, if necessary under confidential cover.

SOCIOECONOMICS/ENVIRONMENTAL JUSTICE

Background: POTENTIAL IMPACTS ON ENVIRONMENTAL JUSTICE COMMUNITIES ALONG RAW MATERIAL AND PRODUCT TRANSPORTATION ROUTES

The AFC identifies several environmental justice communities within a 6-mile radius of the Project site as well as in Tupman, Buttonwillow and Wasco, where the coal storage/transfer facility is located. The AFC determines whether or not these communities might experience disproportionately high and adverse effects as a result of the Project. (AFC, p. 5.8-24.) The AFC does not identify and evaluate potential impacts associated with fuel and product transportation on environmental justice communities along the transport routes for both raw materials and products. These include increased exposure to diesel particulate matter emissions and respirable particulate matter from coal dust losses from uncovered rail cars and the associated incremental cancer risk and other health impacts such as asthma, chronic obstructive pulmonary disease, and chronic bronchitis. In addition, the potential accidental release of hazardous substances along transportation routes may disproportionately affect environmental justice communities.

Data Requests:

93. Please identify environmental justice communities along the rail and truck transport routes for raw materials and products.

94. Please evaluate whether there would be disproportionately high and adverse effects on environmental justice communities along the tracks. Please provide an adequate discussion of potential impacts related to air quality and public health (including emissions of combustion exhaust diesel particulate matter and respirable coal dust losses from transportation) and risks associated with transport of hazardous substances (*e.g.*, anhydrous ammonia).

TRAFFIC AND TRANSPORTATION

Background: IMPACTS ON EXISTING RAIL TRAFFIC ASSOCIATED WITH RAIL TRANSPORT OF RAW MATERIALS AND PRODUCTS

The Project would require up to 20,051 train cars annually for transportation of coal and products (liquid sulfur, gasification solids, ammonia, urea, and urea ammonia nitrate. (AFC, Appx. E-5, p. 3.) The AFC does not discuss the potential impacts on the existing use of rail corridors.

Data Requests:

95. Please discuss the practical and theoretical capacity of the existing rail corridors that would be used for transportation of the Project's raw materials and products.

96. Please discuss whether the additional train cars would result in constraints to the passenger rail system or adversely affect the transport of freight in California and/or New Mexico.

97. Please indicate whether the rail system would require improvements to the existing rail corridors.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A

(Revised 7/25/12)

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DECLARATION OF SERVICE

I, David Abell, declare that on August 2, 2012, I served and filed a copy of the attached **Sierra Club's Data Requests Set No. 1**, Dated August 2, 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;

_X__ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "e-mail preferred."

AND

For filing with the Docket Unit at the Energy Commission:

_X__ by sending one electronic copy to the e-mail address below (preferred method); OR

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

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.

/s/David Abell
David Abell, Sierra Club