Responses to Sierra Club Data Requests Set Three: Nos. 132 through 146

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

Prepared for:
Hydrogen Energy California LLC

hydrogen energy california

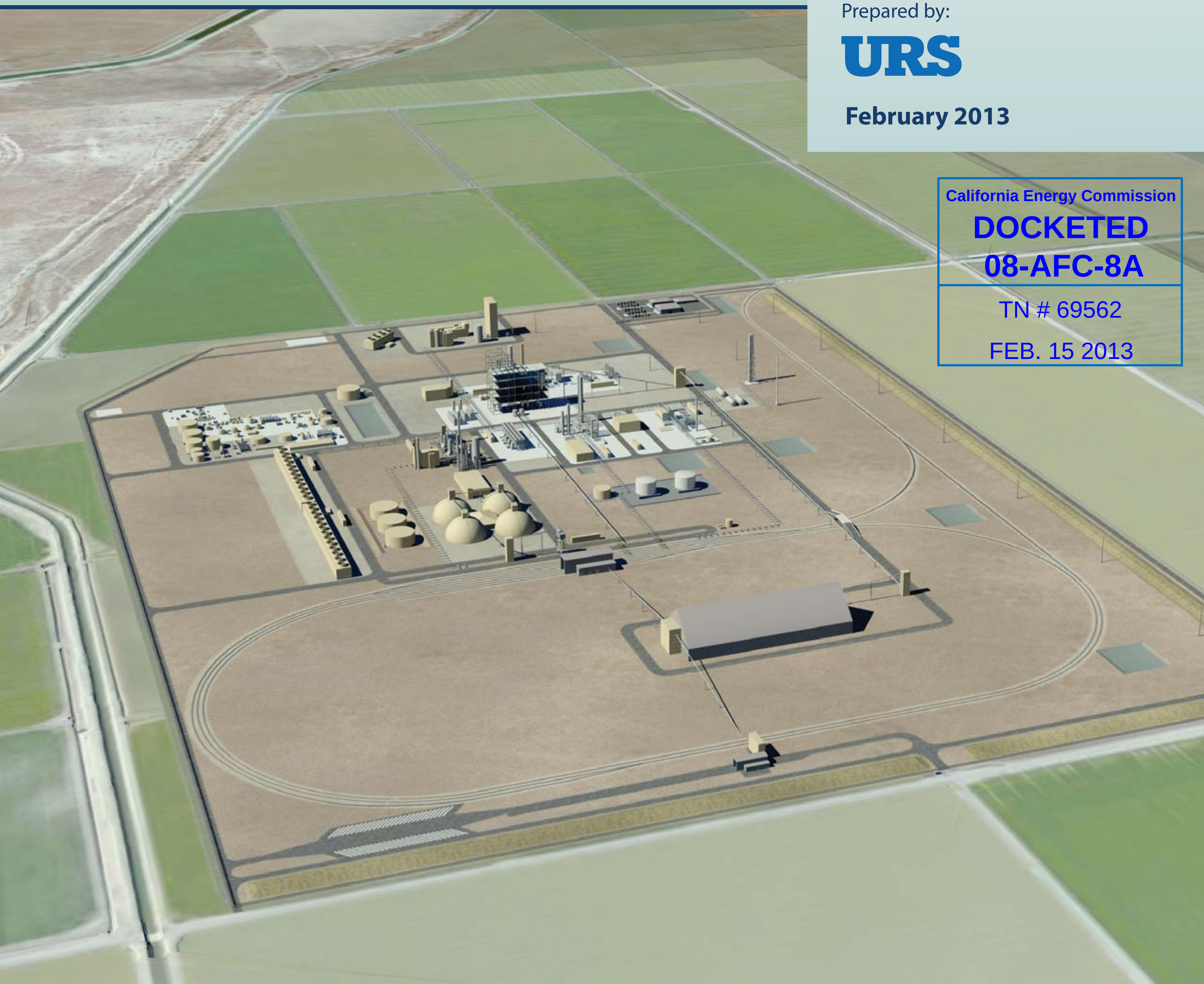
Submitted to:

California Energy Commission

U.S Department of Energy

Prepared by:
URS

February 2013



California Energy Commission
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RESPONSES TO DATA REQUESTS 132 THROUGH 146 FROM SIERRA CLUB

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LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

AFC	Application for Certification
AR	as received
BACT	Best Available Control Technology
Btu	British thermal unit
CEC	California Energy Commission
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CTG	combustion turbine engine
DOE	U.S. Department of Energy
EPA	Environmental Protection Agency (see USEPA)
gw	gigawatt
HECA	Hydrogen Energy California
HRSG	heat recovery steam generator
IGCC	Integrated Gasification Combined Cycle
lb	pound
mg/kg	milligrams per kilogram
mg/L	milligrams per liter
MHI	Mitsubishi Heavy Industries
MMBtu	million British thermal units
MW	Megawatt
NO_X	oxides of nitrogen
petcoke	petroleum coke
PM_{10}	particulate matter 10 microns in diameter or less
$PM_{2.5}$	particulate matter 2.5 microns in diameter or less
ppb	parts per billion
ppmw	parts per million by weight
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur dioxide
SRU	sulfur recovery unit
STPD	short tons per day
Syngas	synthesis gas
TCLP	toxicity characteristic leaching procedure
UAN	urea ammonia nitrate
URBEMIS	Urban Emissions (Software)
USEPA	United States Environmental Protection Agency
VOC	volatile organic compound
WSPA	Western States Petroleum Association

BACKGROUND: FOLLOW-UP: SUPPORT FOR FLARE EMISSION ESTIMATES

The Sierra Club has additional questions regarding the information provided by the Applicant for flare emission estimates.

DATA REQUEST

132. Sierra Club Data Request #38.j was worded incorrectly. Please provide support for the duration and heat input rates (in MMBtu/hr) while flaring natural gas, unshifted syngas, and shifted syngas which appear to be based on "Startup/Shutdown Procedures provided by MHI for the PurGen One Project."

RESPONSE

The PurGen project reference was inadvertently left on the emission calculation tables from earlier draft calculations that preceded the Amended Application for Certification (AFC). The PurGen project reference does not apply to the current Hydrogen Energy California (HECA) Project. The gasifier startup flaring information for emission calculations is based on the engineering estimates Mitsubishi Heavy Industries prepared specifically for the HECA Project, and is still accurate. HECA will accept permit conditions to operate within the annual durations and flaring rates submitted.

DATA REQUEST

133. Please indicate whether the flare will be equipped with a flare gas recovery system for non-emergency releases, as required by the SJVAPCD's BACT Guidelines for refinery flares.

RESPONSE

The configuration and operational characteristics of HECA are not the same as a refinery, and a flare gas recovery system is not used. The flare system will safely dispose of gas streams during unplanned upsets or emergency events, and during startup and shutdown, and their configuration and use is more fully explained in the Amended AFC. Unlike a refinery, HECA does not have a complex internal fuel system and will not have sustained periods of flaring due to imbalances in the fuel system. Also, the sulfur recovery unit flare system will incorporate a caustic scrubber to remove sulfur compounds, and all flares will incorporate features to reduce the potential for leakage to the flare system during non-emergency conditions.

DATA REQUEST

134. As flares do not lend themselves to routine stack testing, estimating flaring emissions based on emission factors must be reasonable and achievable in practice. Please provide a vendor guarantee for the combination of emission factors and control efficiencies used to calculate flare NO_X, CO, VOC, and PM10 emissions as provided under confidential cover in Response to Sierra Club Data Request #24.

RESPONSE

This information was previously requested in Sierra Club Data Request 38.j. Please refer to the Applicant's response to Data Request 38.j and associated attachments for the requested information.

Two updates have since been made to details included in Attachment 38-3, including:

- Under the heading "Gasifier Startup – Startup Gas to Gasification Flare" of Table 1 in Attachment 38-3, the Revised AFC reference in the next row should read Section 2.5.9, not Section 2.5.2.

- The normal operation oxides of nitrogen (NO_x) emission factor has changed from 0.12 to 0.068 pound per million British thermal units (lb/MMBtu). This change was requested by the San Joaquin Valley Air Pollution Control District (SJVAPCD) to be consistent with their Best Available Control Technology (BACT) requirements, and was agreed to by the Applicant on November 5, 2012.

BACKGROUND: ELIMINATION OF ANHYDROUS AMMONIA SALES

In response to Sierra Club Data Request #85, the Applicant stated it has revised the HECA project to eliminate off-site transport and sale of anhydrous ammonia. In response to an inquiry about any associated changes to the facility design and emissions, the Applicant stated at the November 7, 2012 workshop that the only change would be that the anhydrous ammonia loading facility would not be built and there would no changes in emissions.

DATA REQUEST

135. Please confirm that the anhydrous ammonia loading facility will not be constructed.

RESPONSE

HECA no longer has plans to construct an ammonia loading facility.

DATA REQUEST

136. The Amended AFC, p. 5.12-9, indicates that the facility was expected to produce a maximum of 500 tons/day of surplus anhydrous ammonia.

a. Please quantify how many hours/days of ammonia production at full capacity can be accommodated by the Project's two ammonia storage tanks (total 3.8 million gallons).

b. Please discuss whether additional storage tanks will be needed to accommodate the production of surplus anhydrous ammonia that will no longer be transported off-site.

RESPONSE

a. The ammonia storage tanks are designed to hold 7 days of typical daily ammonia production. At maximum ammonia production capacity, the storage tanks would hold approximately 5.1 days of ammonia production. For reference, 500 tons represents 33 percent of a typical day's ammonia production.

b. No additional storage tanks will be needed. During typical operation and for the typical fertilizer production rates, all of the ammonia produced on site will be consumed on site. Therefore, the decision to remove the ammonia-loading facility from the plant design does not change the ammonia storage requirements.

DATA REQUEST

137. Anhydrous ammonia is a precursor product to the production of urea and urea ammonia nitrate ("UAN") at the Project. Please indicate whether the facility would increase production of urea and UAN fertilizer as a consequence of eliminating direct sales of anhydrous ammonia.

RESPONSE

As noted in the response to Sierra Club Data Request 136.b, the planned fertilizer (urea and urea ammonia nitrate [UAN] solution) production was based on zero anhydrous ammonia sales. Therefore, the decision to remove the ammonia-loading facility from the plant design does not impact the fertilizer production rates. If anhydrous ammonia sales had occurred, it would have necessitated either a decrease in power output or a decrease in fertilizer production (urea and/or UAN).

BACKGROUND: FOLLOW-UP: FUGITIVE ENTRAINED ROAD DUST PARTICULATE MATTER EMISSIONS FROM ON-SITE MOBILE SOURCES

Sierra Club Data Request #113 requested that the Applicant include on-site fugitive entrained road dust in the Project's potential to emit ("PTE"), which is provided in the Amended AFC in Table 5.1-14, p. 5.1-83. The Applicant's response refers to the Amended AFC Tables 5.1-20 (Alternative 1) and 5.1-31 (Alternative 2) and supporting appendices (E-3 and E-12, respectively) for fugitive dust emission estimates for on-site mobile sources and states that these emissions were included in the modeling. This response does not address the Sierra Club's request to include the on-site mobile source emissions in Table 5.1-14, which is entitled HECA Total Combined Annual Criteria Pollutant Emissions.

The inset table below shows revised Table 5.1-14 from the emission calculation spreadsheets provided under confidential cover by the Applicant in response to Sierra Club Data Request #24.

						11/8/2012
HECA Total Combined Annual Criteria Pollutant Emissions						
Pollutant / Equipment	**NO_X**	**CO**	**VOC**	**SO_2**	**PM_{10}**	**$PM_{2.5}$**
	tons/year					
HRSG/CTG (1)	106.5	89.0	15.1	17.1	54.0	54.0
Coal Dryer (1)	17.0	12.7	2.4	2.8	5.6	5.6
Auxiliary Boiler	1.4	8.6	0.9	0.5	1.2	1.2
Tail Gas Thermal Oxidizer	13.4	11.2	0.3	8.3	0.4	0.4
CO_2 Vent		124.1	2.8			
Gasification Flare	2.5	18.5	0.01	0.02	0.03	0.03
Rectisol Flare	0.7	0.8	0.01	0.3	0.03	0.03
SRU Flare	0.1	0.2	0.003	0.4	0.006	0.006
Cooling Towers (2)					25.5	15.3
Emergency Generators (3)	0.2	0.8	0.1	0.001	0.02	0.02
Fire Water Pump	0.09	0.2	0.01	0.0003	0.001	0.001
Nitric Acid Unit	17					
Urea Pastillation Unit					0.2	0.2
Ammonium Nitrate Unit					0.8	0.8
Ammonia Startup Heater	0.04	0.14	0.02	0.01	0.02	0.02
Material Handling (4)					2.3	2.3
Fugitives	0.005	6.0	16.7	0.1		
Total Annual	**158.8**	**272.1**	**38.4**	**29.5**	**90.1**	**79.9**
Source: HECA Project						
Notes:						
(1) Total annual HRSG and Coal Dryer emissions represent the maximum annual emissions during normal operations plus startup and shutdown emissions						
(2) Includes contributions from all three cooling towers						
(3) Includes contributions from both emergency generators						
(4) Material handling emissions are shown as the contribution of all dust collection points.						

REDACTED

The red arrows show where fugitive entrained road dust PM2.5 and PM10 emissions should have been included but were not.

The requirement to include fugitive road dust emissions in the Project's PTE stems from 40 CFR §52.21(b)(1)(iii), which specifies that sources that fall in one of the 28 named industrial source categories listed at 40 CFR §52.21(b)(1)(i)(a) must take into consideration fugitive emissions when determining whether they reach the 100 ton per year emissions threshold to determine major source status. The Project falls within the source category "Fossil fuel-fired steam electric plant of more than 250 million Btu per hour heat input."

DATA REQUEST

138. Please update Table 5.1-14 to include on-site entrained road dust particulate matter emissions according to 40 CFR §52.21(b)(1)(iii) and submit the revised table to the SJVAPCD. Please use the appropriate silt loading factor for paved roads at industrial facilities from U.S. EPA's Compilation of Air Pollutant Emission Factors ("AP-42"), Section 13.2.1, Paved Roads, to calculate emissions.

RESPONSE

The fugitive dust emissions associated with onsite vehicular travel have been added to Amended AFC Table 5.1-14, and are included in Table 138-1 below. As noted in the previous response to Sierra Club Data Request 113, these emissions were presented in the Amended AFC in Table 5.1-20 and Appendix E-3 for Alternative 1 (Rail Transportation), and Table 5.1-31 and Appendix E-12 for Alternative 2 (Truck Transportation).

The silt loading factor used is the Urban Emissions software (URBEMIS) default value for paved roads in Kern County, and is thus appropriate for these emission calculations. As noted in Sierra Club Data Request 27, "The silt loading default value used in URBEMIS 9.2 applies only to operational traffic associated with a project…" This silt loading factor has been used to calculate the fugitive dust emissions associated with operations, as Sierra Club has previously pointed out is appropriate.

Additionally, the AP-42 table referenced for paved roads at industrial facilities (Table 13.2.1-3) is not applicable to the HECA Project. The listed facility types are extremely different from the HECA Project (e.g., copper smelting, sand and gravel processing) and would significantly overestimate silt loading.

Table 138-1 (Revised Table 5.1-14)
Total Combined Annual Criteria Pollutant Emissions[1]

Equipment / Pollutant	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
	tons/yr					
HRSG/CTG	106.5	89.0	15.1	17.1	54.0	54.0
Coal Dryer	17.0	12.7	2.4	2.8	5.6	5.6
Auxiliary Boiler	1.4	8.6	0.9	0.5	1.2	1.2
Tail Gas Thermal Oxidizer	13.4	11.2	0.3	8.3	0.4	0.4
CO_2 Vent	N/A	124.1	2.4	N/A	N/A	N/A
Gasification Flare	2.5	18.5	0.01	0.02	0.03	0.03
Rectisol® Flare	0.7	0.8	0.01	0.3	0.03	0.03
SRU Flare	0.1	0.2	0.003	0.4	0.006	0.006
Cooling Towers[2]	N/A	N/A	N/A	N/A	25.5	15.3
Emergency Generators[3]	0.2	0.8	0.1	0.001	0.02	0.02
Fire Water Pump	0.09	0.2	0.01	0.0003	0.001	0.001
Nitric Acid Unit	17	N/A	N/A	N/A	N/A	N/A
Urea Pastillation Unit	N/A	N/A	N/A	N/A	0.2	0.2
Ammonium Nitrate Unit	N/A	N/A	N/A	N/A	0.8	0.8
Ammonia Start-Up Heater	0.04	0.1	0.02	0.01	0.02	0.02
Material Handling[4]	N/A	N/A	N/A	N/A	2.3	2.3
Fugitives	0.005	6.0	16.7	0.1	0.1	0.03
Total Annual	**158.8**	**272.1**	**38.0**	**29.5**	**90.2**	**79.9**

Source: HECA 2012

Notes:

1. Total annual emissions represent the maximum annual emissions during operations plus start-up and shut-down emissions
2. Includes contributions from all three cooling towers
3. Includes contributions from both emergency generators
4. Material handling emissions are shown as the contribution of all dust collection points.

HRSG = Heat Recovery Steam Generator
CTG = combustion turbine generator
CO = carbon monoxide
CO_2 = carbon dioxide
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
SRU = sulfur recovery unit
VOC = volatile organic compound

BACKGROUND: MALFUNCTIONING EMISSIONS

In response to Sierra Club Data Request #116, the Applicant states that based on the project design, and the operating experience at the Nakoso plant, no malfunction flare events are expected.

DATA REQUEST

139. Would the Applicant be willing to accept a condition of certification ("CoC") limiting the number of startups/shutdowns including unplanned startups/ shutdowns to two per year on a rolling 12-month average?

RESPONSE

As indicated previously, the analysis presented in the Amended AFC accounts for all planned flaring events, including the temporary flaring during unit startup and shutdown operations. The estimate is based on two complete plant-wide shutdowns and startups annually, even though only one shutdown is planned. HECA anticipates receiving emission-based limits that address all operations and emission sources, and believes this is the most appropriate way to regulate these emissions.

BACKGROUND: MERCURY REMOVAL SYSTEMS

In response to CEC Data Request #A135, the Applicant indicates that the Project would use adsorbent(s) such as activated carbon or alumina as in the Project's two mercury removal systems.

DATA REQUEST

140. Please provide a discussion of the mercury control technology with alumina that would potentially be used for the Project.

RESPONSE

The alumina-based control technology is very similar to activated carbon control technology for controlling mercury. The main difference is that activated alumina is used as the adsorbent instead of activated carbon. The alumina-based mercury removal technology involves passing the sour synthesis gas (syngas) through a fixed bed of alumina adsorbent. The mercury is removed from the syngas with activated alumina adsorbent that has been impregnated with elemental sulfur. Prior to flowing through the adsorbent bed, the syngas is heated to eliminate any liquid water drops that could decrease life of the adsorbent bed.

BACKGROUND: WASTE FROM MERCURY REMOVAL SYSTEMS

The information regarding the waste characterization and disposal of spent adsorbent(s), i.e., activated carbon and/or alumina from the Project's two mercury removal systems is not adequate.

DATA REQUEST

141. Please quantify the amount of adsorbent(s) that would be required annually separately for a) the fixed bed adsorber just upstream of the acid gas removal system and b) for the mercury removal system for the feedstock dryer exhaust.

RESPONSE

a. The adsorbent required for the fixed-bed adsorber just upstream of the acid gas removal system is 3 tons per year, as indicated in the Amended AFC Table 5.13-3, if activated carbon is used as the adsorbent. The adsorbent required if alumina is used as the adsorbent is 6 tons per year. These values are annualized values based on the expected adsorbent life and the resulting interval between adsorbent bed replacements.

b. The adsorbent required for the feed stock dryer mercury removal system is up to 400 tons per year. It is anticipated that carbon adsorbent used here will be recycled back to the gasifier to recover the fuel value of the carbon and avoid creating a waste stream. The adsorbed mercury in the recycled carbon will be desorbed in the gasifier and partition to the syngas. The mercury from the recycled carbon, plus most of the remaining mercury from the feedstock, will be removed in the downstream syngas adsorption bed.

DATA REQUEST

142. The Amended AFC, Table 5.13-3, p. 5.13-10, states that spent mercury removal carbon beds (impregnated activated carbon) would be stabilized and disposed of at a hazardous waste landfill. However, the Land Disposal Restrictions of the 1984 Hazardous and Solid Waste Amendments to the Resource Conservation and Recovery Act require that mercury in wastes with contamination levels at or above 260 parts per million ("ppm") mercury be recovered by a thermal process, such as retorting, and stabilized using an amalgamation process. The treatment standard for "high mercury inorganic category" wastes, which contain more than 260 mg/kg total mercury, is mercury recovery in a thermal processing unit that volatilizes and subsequently condenses the mercury. These units are commonly referred to as "retorters," and the recovery process as "retorting." (40 CFR §268.42, Table 1).

a. Please specify the mercury content of the spent adsorbents and discuss the required treatment of the waste products.

b. The Amended AFC, p. 5.13-5 and Table 5.13-1, identifies two Class I landfills in California, Chemical Waste Management's Kettleman Hill's Landfill in Kings County and Clean Harbors' Buttonwillow facility in Kern County for disposal of hazardous waste. Please discuss whether either of these facilities is equipped to retort mercury waste.

RESPONSE

a. The spent adsorbents would be characterized after they are generated. Preliminary design information indicates that the estimated mercury concentration of the spent mercury removal adsorbent from the syngas fixed-bed adsorber upstream of the acid gas removal system would exceed the Resource Conservation and Recovery Act Land Disposal Restrictions limit of parts per million weight ([ppmw] or milligrams per kilogram [mg/kg]), for both the carbon and alumina adsorbent alternatives. Consequently, this waste stream would require recovery by a thermal process, such as retorting.

Spent carbon adsorbent that contains mercury in concentrations greater than or equal to 260 mg/kg may be characterized as "High Mercury-Organic Subcategory" per the table of Treatment Standards for Hazardous Wastes in 40 Code of Federal Regulations (CFR) Section 268.40. Such wastes must be treated by "IMERC" (defined in 40 CFR Section 268.42 as incineration) or "RMERC" (defined in 40 CFR Section 268.42 as retorting or roasting in a thermal processing unit capable of volatilizing mercury and subsequently condensing the volatilized mercury for recovery). The treatment standard for residues from RMERC with total concentrations less than 260 mg/kg mercury is a maximum leachate concentration of 0.20 milligram per liter (mg/L) (measured by toxicity characteristic leaching procedure [TCLP]).

Spent alumina adsorbent that contains mercury in concentrations greater than or equal to 260 mg/kg may be characterized as "High Mercury-Inorganic Subcategory" per the table of Treatment Standards for Hazardous Wastes in 40 CFR Section 268.40. Such wastes must be treated by RMERC. As explained in the paragraph above, the treatment standard for residues from RMERC with total concentrations less than 260 mg/kg mercury is a maximum leachate concentration of 0.20 mg/L (measured by TCLP).

Adsorbent is also used to remove mercury from the feedstock dryer exhaust gas in the gasifier feed preparation area; and preliminary design information projects the mercury concentration in the spent adsorbent to be less than 260 mg/kg. It is anticipated that the adsorbent used here will be carbon, and the spent carbon will be recycled back to the gasifier to recover the fuel value in the carbon, and with the mercury captured and removed by the syngas fixed-bed adsorber. This would avoid the creation of an additional waste stream.

b. The California landfills listed in Sierra Club Data Request 142.b are not permitted for retorting of high-mercury waste. Spent adsorbents that are confirmed to contain mercury concentrations of more than 260 mg/kg would be sent to a permitted recovery or treatment facility, such as Bethlehem Apparatus in Hellertown, Pennsylvania, or Waste Management-Mercury Waste Inc. in Union Grove, Wisconsin.

BACKGROUND: FOLLOW-UP: COMPLIANCE WITH MERCURY AND AIR TOXICS STANDARDS

In response to CEC Data Request #A135, the Applicant provided calculations to demonstrate compliance with the Mercury and Air Toxics Standards ("MATS"). The provided information is not sufficient to evaluate potential impacts on the environment and the provided calculations appear to be based on a number of incorrect and/or not adequately assumptions.

DATA REQUEST

143. The mercury emission calculation is based on a coal feed rate to the gasifier of 3,900 short tons per day ("stpd") on a dry basis, which is based on the assumption that the Project would be using 75% coal and 25% petcoke and the assumption that petcoke has a negligible mercury content.

a. Please provide information about mercury content (typical and range) of petcoke.

b. Please explain how the coal feed rate of 3,900 stpd on a dry basis was derived, e.g., based on equipment specifications or derived from the as-received coal feed rate of 4,950 stpd and a moisture content of 14.8% in typical sub-bituminous coal.

c. Would the Applicant be willing to accept a condition of certification ("CoC") limiting the Project to using at least 25% petcoke on an annual average basis? Alternatively, would the Applicant be willing to accept a CoC limiting the daily coal feed to the gasifier to 3,900 stpd or 1,423,500 short tons per year ("stpy") on a dry basis? If not, please discuss why not, and discuss any other permit or equipment limitations that would limit the coal feed rate to the gasifier.

d. If the answer to the above data request is no, please revise the calculated mercury emission rate to account for the highest potential percentage of coal in the feed rate, i.e., absent any other limitations to 100%.

RESPONSE

a. Investigations on mercury content of petroleum products have been sponsored by the Western States Petroleum Association (WSPA) and the United States Environmental Protection Agency (USEPA). The WSPA Study consisted of taking samples of petroleum coke (petcoke) from four refineries with a total of five coke production units. The results indicated that the mercury content of petcoke ranged between 0.6 to 4.4 parts per billion (ppb) (WSPA, 2009). The USEPA Study indicates that total mercury in petcoke was reported as part of the USEPA reporting requirements on fuel feeds to utility boilers (USEPA, 2000), and the mean of 1,000 samples is approximately 50 ppb.

b. The coal feed rate of 3,900 short tons per day (STPD) was calculated as follows:

    1. The feed rate of coal is 4,580 STPD on an as-received (AR) basis for the 75 percent coal and 25 percent coke case at the design plant production rate, as specified in Amended AFC Sections 2.1.11.1 and 2.1.11.2.

2. Using the typical moisture content of 14.8 percent of the coal from Amended AFC Table 2-5, the flow rate of coal was converted to a dry basis.

3. 4,580 STPD (AR) multiplied by (1.0 – minus 0.148) equals 3,902 STPD (dry). This value was rounded to 3,900 STPD (dry).

4. Note that the 75 percent coal and 25 percent coke split are based on the heating value of the components, not the mass flow.

c. It is important for the HECA Project to maintain sufficient fuel diversity and maximize the number of potential fuel suppliers; this is necessary to minimize fuel costs and avoid curtailment caused by short-term disruptions in fuel supply that can occur in the absence of sufficient flexibility. Furthermore, HECA's specific Cooperative Agreement and Section 48A tax credits require that HECA use coal for at least 75 percent of the energy input for operations for the first 2 and 5 years, respectively, under each agreement. Accordingly, the Applicant would be willing to consider a target of 75 percent coal for the HECA Project's gasification feedstock (heat input basis), provided this is computed on an annual averaging basis, and there is sufficient margin to allow the HECA Project to run above the average during the first 5 years of operations to ensure meeting the minimum regulatory requirements.

d. The requested calculation is provided in the Applicant's response to Sierra Club Data Request 145.

References

Environmental Protection Agency, 2001. *Mercury in Petroleum and Natural Gas: Estimation of Emissions from Production, Processing, and Combustion*. EPA/600/R-01/066 – Page 58. September.

WSPA (Western States Petroleum Association), 2009. *Bay Area Petroleum Refinery Mercury Air Emissions, Deposition, and Fate*, *Appendix A-8.* WSPA Member Facilities San Francisco Bay Area, California Project No. 0032209. June.

DATA REQUEST

144. The mercury emission calculation is based on a number of unsupported assumptions including uncontrolled mercury in feedstock dryer exhaust of 0.002 pounds per hour ("lb/hr") based on "Mitsubishi Heavy Industries estimate;" removal efficiency of 75 percent for feedstock dryer exhaust gas mercury removal system; mercury removal efficiency of 98 percent for fixed bed adsorber bed upstream of acid gas removal system; and split of exhaust from normal operation of the heat recovery steam generator ("HRSG") into 85 percent to the HRSG stack and 15 percent to coal dryer stack.

a. Please provide adequate documentation such as a vendor guarantees to support each of these assumptions, if necessary under confidential cover.

b. Provide a summary of achieved-in-practice mercury removal efficiency at IGCC plants using the proposed technology and identify a conservative removal efficiency. Please revise your mercury emission estimates accordingly.

c. Please discuss and quantify mercury emissions during startup/shutdown.

RESPONSE

a. Attachments 144-1 and 144-2 describe Mitsubishi Heavy Industries' (MHI's) methodology for estimating mercury volatilization and removal in the feedstock dryer and provides MHI's guarantee for the mercury emissions from the dryer stack. Attachment 144-3 provides a mercury removal supplier quotation that shows the syngas mercury adsorption system can be guaranteed to achieve the required performance, which will be at least 99 percent efficient.

The heat recovery steam generator (HRSG) flue gas slip stream rate to the feedstock dryer does not have a significant effect on overall plant emission rates, since the overall HRSG exhaust and emissions quantities are not affected by the amount of gas sent to the dryer (except for minor fluctuations in particulate emissions due to the feedstock dryer exhaust baghouse filter). The total amount of HRSG flue gas and emissions emitted from the HRSG stack and dryer stack will be the same. This is especially true for the mercury, since almost all of the mercury removal occurs in the syngas adsorption system well upstream of the flue gas split to the feedstock dryer.

b. The U.S. Department of Energy (DOE) provided information in their report "The Cost of Mercury Removal in an IGCC." They indicate that mercury removal in an Integrated Gasification Combined Cycle (IGCC) power plant can be expected to be very high in removal effectiveness, low in cost, and reliable in design. This in fact has been substantiated at the Eastman Kingsport gasification facility, where they have demonstrated "essentially complete volatile mercury removal over 95 percent" for over 25 years (Parsons Infrastructure and Technology Group Inc., 2002).

c. Mercury emissions during gasifier startup or shutdown will be less than or equivalent to normal steady-state plant operation. As explained by MHI in Attachment 144-1, activated-carbon injection for the feedstock dryer exhaust will start simultaneously with feed injection, so there will not be uncontrolled mercury emission from the feedstock dryer. The syngas adsorber will start removing mercury as soon as mercury-containing materials flow through it. The operation of the syngas adsorber is completely passive and requires no heating or injection of chemical reagents or other supplemental materials to operate normally.

Reference

Parsons Infrastructure and Technology Group Inc., 2002. *The Cost of Mercury Removal in an IGCC*, Plant Final Report. September.

ATTACHMENT 144-1
FEEDSTOCK DRYER MERCURY EMISSION ESTIMATE

To: "Chet.Leeds@fluor.com" <Chet.Leeds@fluor.com>,
"Jim.Loney@fluor.com" <Jim.Loney@fluor.com>, "John.Ruud@Fluor.com"
Cc: <John.Ruud@Fluor.com>, "William.Becktel@Fluor.com" <William.Becktel@Fluor.com>,
HECA MHI <heca-mhi@mpshq.com>,
Bcc:
Subject: RE: Sierra Club Data Request No. Feedstock Dryer Hg Emission
From: "Ishizu, Yasunori" <yasunori.ishizu@mpshq.com> - Wednesday 02/06/2013 10:35 AM

History: This message has been replied to and forwarded.

Chet-san,

Please find our reply below.

1. Please advise what the source was -- documentation (if any), calculation, etc -- for the value of 0.002 lb/hr of uncontrolled mercury emissions in MHI's original data table.

[Mitsubishi] Uncontrolled mercury emissions is calculated based on our R&D program results about mercury emissions at the coal drying system conducted at our pilot plant in the past.

2. Also, please advise "when" in the process is the activated carbon actually injected in the feed stock drying stack during startup (note, yesterday you indicated that carbon injection started soon as the feed stock is introduced and the drying process begins).

[Mitsubishi] As you noted, Mitsubishi confirms that it is planned to start activated carbon injection soon as the feed stock is introduced and the drying process begins.

Should you have any questions, please let us know.

Best Regards,

Yasunori

Yasunori Ishizu
Manager, Boiler and IGCC Engineering
Mitsubishi Power Systems Americas, Inc.
Fluor Office; ext 5677
Mob: +1-407-965-8428
E-mail: yasunori.ishizu@mpshq.com

ATTACHMENT 144-2
FEEDSTOCK DRYER MERCURY EMISSION GUARANTEE

RE: Sierra Club's Motion to Extend Discovery and Data Request No. 3 Docket No. 08-AFC-08A
Ishizu, Yasunori
to:
Chet.Leeds@fluor.com
01/22/2013 04:09 PM
Cc:
"John.Ruud@Fluor.com", "Jim.Loney@fluor.com", "William.Becktel@Fluor.com", "laura.bullock@fluor.com", "robert.gross@fluor.com", "Higaki, Takao", "Fujino, Tetsuya", "Kato, Hideyuki", "Sakai, Ryosuke", HECA MHI
Show Details

History: This message has been replied to.

Dear Mr. Leeds,

With respect to the Sierra Club Data Request Set No.3 - 144a dated Dec. 30, 2012, please find our confirmation on guarantee for mercury emission from the gasifier stack below.

Mitsubishi Heavy Industries confirms to include the guarantee of the Gasifier feedstock dryer mercury emission of 0.0005 lb/h or less in EPC contract.

Best Regards,
Yasunori

Yasunori Ishizu
Manager, Boiler and IGCC Engineering
Mitsubishi Power Systems Americas, Inc.
Fluor Office; ext 5677
Mob: +1-407-965-8428
E-mail: yasunori.ishizu@mpshq.com

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ATTACHMENT 144-3
SYNGAS MERCURY REMOVAL GUARANTEE

RE: Performance guarantee statement required for RBGH 3 Fluor Hg removal project

Patrick Flanagan to: Jim.Loney@fluor.com 02/07/2013 02:09 PM

Cc: "Robert.Gross@Fluor.com", "Jared.Monk@fluor.com", "John.Ruud@Fluor.com", "William.Becktel@Fluor.com", "Laura.Bullock@fluor.com", "sc.a4uv.project@fluor.com"

History: This message has been replied to and forwarded.

Hi Jim,
Since the mechanism is chemisorption, the capacity would remain at 15% by weight with a >99% efficiency still expected.

Please let me know if you have any further questions.
Thanks and regards,

Patrick Flanagan
Southwestern Regional Manager
Norit Americas Inc.

Direct 714 914 1111
Email pflanagan@norit-americas.com

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Norit Activated Carbon
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From: Jim.Loney@fluor.com [mailto:Jim.Loney@fluor.com]
Sent: Wednesday, February 06, 2013 1:54 PM
To: Patrick Flanagan
Cc: David Herrera; Robert.Gross@Fluor.com; Jared.Monk@fluor.com; John.Ruud@Fluor.com; William.Becktel@Fluor.com; Laura.Bullock@fluor.com; sc.a4uv.project@fluor.com
Subject: Re: Performance guarantee statement required for RBGH3 Fluor Hg removal project

Patrick,

Thank you for speaking with me on the telephone today. As we discussed, Fluor continues to develop responses to the California Energy Commission data requests and we find that there may be off-design conditions where the incoming mercury concentration may be as high as 43 micrograms per Nm3. What would the expected performance of the activated carbon be with this higher inlet concentration at the maximum syngas flow rate shown on the data sheet?

Jim Loney, PE | **FLUOR** | Director - Process Engineering | jim.loney@fluor.com | O 1.949.349.7490 | M 1.714.824.9969 | IODC 30-7490 | www.fluor.com

From: Patrick Flanagan <Patrick.Flanagan@cabotcorp.com>

To: "Robert.Gross@Fluor.com" <Robert.Gross@Fluor.com>
Cc: David Herrera <David.Herrera@cabotcorp.com>, "Jim.Loney@fluor.com" <Jim.Loney@fluor.com>, " William.Becktel@Fluor.com" <William.Becktel@Fluor.com>, "Laura.Bullock@fluor.com" <Laura.Bullock@fluor.com>, " John.Ruud@Fluor.com" <John.Ruud@Fluor.com>, "sc.a4uv.project@fluor.com" <sc.a4uv.project@fluor.com>, " jared.monk@fluor.com" <jared.monk@fluor.com>

Date: 01/25/2013 12:06 PM

Subject: Performance guarantee statement required for RBGH3 Fluor Hg removal project

Robert,
Pursuant to your request for a conditional performance guarantee on Norit RBGH3 carbon for the HECA Project (# A4UV), please find our response in blue:

"Norit RBHG 3 is conditionally guaranteed to achieve >99% removal of mercury for three years. The performance guarantee is based on a minimum bed residence time of 10 seconds at a velocity less than 60 fpm. Operating conditions for the system must not exceed 60 degrees C, and must have less than or equal to 20 micrograms/Nm3 mercury concentration at the inlet of the carbon adsorber. In the event Norit RBHG 3 does not achieve this level of performance at the stated conditions, Norit Americas Inc. will extend a prorated refund or discount based on the initial value of the carbon."

Please do not hesitate to contact David Herrera or myself for further clarification or assistence.

Thanks and regards,

Patrick Flanagan
Southwestern Regional Manager
Norit Americas Inc.

Direct 714 914 1111
Email pflanagan@norit-americas.com

Norit Has a New Website!
Please visit www.norit.com to see our new interactive website.
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leading in purification
Activated Carbon

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DATA REQUEST

145. The mercury emission calculation is based on a mercury concentration in the coal feed of 0.09 parts per million by weight ("ppmw"), which is the typical mercury content for a sub-bituminous coal (as presented in the Amended AFC, Table 2-5, p. 2-81.) However, in response to Sierra Club Data Request #17, the Applicant has indicated that it will receive coal from a portfolio of mines but most likely from Peabody's El Segundo mine, which has a typical mercury content of 0.12 ppmw. Based on a mercury content of 0.12 ppmw and otherwise using the Applicant's assumptions, HECA's mercury emission rate can be calculated at 0.003 pounds per Gigawatt-hour ("lb/GWh") which is equal to the applicable MATS standard for mercury. Please revise the calculated mercury emission rate to account for the typical mercury content in coal from the El Segundo mine of 0.12 ppmw and discuss compliance with the applicable MATS mercury standard of 0.003 lb/GW-h. Please take into account guidance by the U.S. Environmental Protection Agency regarding rounding of significant figures. (See, e.g., http://www.epa.gov/ttn/emc/rounding.pdf and http://yosemite.epa.gov/oaqps/EOGtrain.nsf/fabbfcfe2fc93dac85256afe0048 3cc4/4939717614a0227e85256f400062252e/$FILE/Lesson2.pdf.

RESPONSE

Recent information for mercury in El Segundo coal indicates using a value of 0.13 part per million by weight (dry basis). This value and other El Segundo coal properties, plus a recently received supplier proposal for a mercury removal system, have been used to update the mercury emission compliance calculation previously submitted in response to California Energy Commission (CEC) Data Request A135. The syngas mercury removal system supplier description and guarantee are presented in Attachment 144-3. The emissions are calculated on a 100 percent coal basis, because this would produce the maximum mercury emissions, although the Project is expected to operate with a feedstock blend of 75 percent coal and 25 percent petcoke. The updated mercury emission calculation is provided below.

Mercury Emission Calculation – 100% El Segundo Coal Feed

Gasifier coal feed (dry basis) = 5023 tons/day (based on El Segundo coal)
Coal mercury concentration (dry basis) = 0.13 ppmw
Mercury in gasifier feed = 0.05442 pound per hour (lb/hr)

Uncontrolled mercury in feedstock dryer exhaust (pro-rated MHI estimate) = 0.0028 lb/hr
Feedstock dryer mercury removal = 75 percent
Feedstock dryer mercury emission = 0.00069 lb/hr

Assume that all mercury removed from the feedstock dryer exhaust becomes part of the gasifier feedstock, and subsequently, part of the syngas stream.

Inlet mercury to syngas adsorber bed = 0.05442 – 0.00069 = 0.0537 lb/hr
Adsorber removal = 99 percent
Estimated HRSG flue gas mercury = 0.000537 lb/hr

About 85 percent of the HRSG flue gas mercury will be emitted through the HRSG stack and the remainder through the feedstock dryer stack. It is assumed that the mercury in HRSG flue gas sent to the dryer will be reduced by the dryer mercury removal system, therefore:

Feedstock dryer mercury emission = 0.00069 lb/hr + (0.000537 lb/hr * 0.15 * 0.25)

HRSG mercury emission = 0.000537 lb/hr * 0.85

Summary

Feedstock dryer emission	= 0.000710 lb/hr
HRSG emission	= 0.000457
Total plant	0.001167 lb/hr
Total mercury/gross power	= 0.001167 lb/hr/405 megawatt (MW) x 1,000 MW/gigawatt
	= 0.00288 lb/gigawatt hour

DATA REQUEST

146. The Applicant states that it intends to measure filterable particulate matter as a surrogate for metal toxics and relies on an expected emission rate of 14.3 lb/hr to calculate emissions of 0.035 lb/MWh.

a. Please demonstrate how the expected emission rate of 14.3 lb/hr filterable particulate matter was derived. Please document your assumptions.

b. Please indicate whether the Project would determine filterable particulate matter concentrations in exhaust gas with a continuous emissions monitor or by stack testing.

RESPONSE

a. The particulate emission rate of 14.3 lb/hr shown in the response to CEC Data Request A135 is taken from the Amended AFC as referenced in the response to the CEC data request. It is the estimated maximum combined particulate matter 10 microns in diameter or less (PM_{10}) emission from the HRSG and gasification feedstock dryer. The Applicant and its consultants conservatively estimated the worst-case PM_{10} emissions by considering a variety of factors, including the clean burning characteristics of hydrogen-rich fuel, maximum sulfur levels comparable to natural gas, only trace amounts of hydrocarbons and other reduced forms of carbon that can cause carbonaceous soot, and the natural gas source test data for other advanced gas turbine-based combined cycle plants. It is conservatively based on the maximum expected filterable plus condensable particulate measurements because there is no basis to estimate the filterable/condensable split for this equipment and this fuel and because the combined value is still well below the surrogate standard.

b. HECA expects to demonstrate compliance with particulate standards using periodic stack source testing.

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
PROOF OF SERVICE
(Revised 2/11/13)

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<u>OTHER ENERGY COMMISSION
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CONVENIENCE ONLY):</u>

After docketing, the Docket Unit will provide a copy to the persons listed below. Do not send copies of documents to these persons unless specifically directed to do so.

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Commissioner and Presiding Member

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Raoul Renaud
Hearing Adviser

Galen Lemei
Adviser to Presiding Member

Jennifer Nelson
Adviser to Presiding Member

David Hungerford
Adviser to Associate Member

Patrick Saxton
Adviser to Associate Member

Eileen Allen
Commissioners' Technical
Adviser for Facility Siting

DECLARATION OF SERVICE

I, Dale Shileikis, declare that on February 15, 2013, I served and filed copies of the attached Sierra Club Data Requests Set Three: Nos. 132 through 146, dated February, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

The document has been sent to the other persons on the Service List above in the following manner:

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For service to all other parties and filing with the Docket Unit at the Energy Commission:

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I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, and that I am over the age of 18 years.

Dated: 2/15/13 ________________