Responses to Sierra Club Data Requests – Nos. 98 through 131

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

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RESPONSES TO DATA REQUESTS 98 THROUGH 131 FROM SIERRA CLUB

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LIST OF ACRONYMS AND ABBREVIATIONS USED IN RESPONSES

ACC	air-cooled condenser
AFC	Application for Certification
BACT	Best Available Control Technology
BGRP	Brackish Groundwater Remediation Project
Btu	British thermal unit
BVWSD	Buena Vista Water Storage District
CAAQS	California Ambient Air Quality Standards
CEC	California Energy Commission
CEQA	California Environmental Quality Act of 1970
CO	carbon monoxide
CO_2	carbon dioxide
COS	carbonyl sulfide
DPR	Department of Water Resources
EFSEC	Energy Facility Site Evaluation Council
EPA	Environmental Protection Agency (see USEPA)
FEIR	final environmental impact report
H_2S	hydrogen sulfide
HAP	Hazardous Air Pollutant
HECA	Hydrogen Energy California
HRSG	heat recovery steam generator
IGCC	Integrated Gasification Combined Cycle
KCWA	Kern County Water Agency
$\mu g/m^3$	micrograms per cubic meter
MATS	mercury and air toxics standards
mg/L	milligrams per liter
MHI	Mitsubishi Heavy Industries
MMBtu	million British thermal units
NAAQS	National Ambient Air Quality Standards
NDA	non-disclosure agreement
NGCC	natural gas combined cycle
NO_2	nitrogen dioxide
NO_X	oxides of nitrogen
O&M	operation and maintenance
PM	particulate matter
PM_{10}	particulate matter 10 microns in diameter or less
$PM_{2.5}$	particulate matter 2.5 microns in diameter or less
PTE	potential to emit
SCR	selective catalytic reduction
SILs	Significant Impact Levels
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	Sulfur dioxide
SRU	sulfur recovery unit
Syngas	synthesis gas
TDS	total dissolved solids
USEPA	United States Environmental Protection Agency
VOC	volatile organic compound

BACKGROUND: DOCUMENTS SUBMITTED TO CEC UNDER CONFIDENTIAL COVER IN PRIOR PROCEEDING (08-AFC-08)

During the prior Application for Certification ("AFC") proceedings for the Hydrogen Energy California ("HECA") Project (08-AFC-08), the Applicant submitted several documents to the California Energy Commission ("CEC") under confidential cover. The Applicant's August 2012 Response to CEC Data Request No. A1 indicates that these documents remain applicable in their originally submitted form to the current revised HECA Project under the amended proceedings (08-AFC-08A). Sierra Club requests a copy of these documents under confidential cover to evaluate the potential environmental impacts of the HECA Project.

DATA REQUEST

98. Please provide under confidential cover Applicant's 2009 Response to CEC Data Request No. 115 (08-AFC-08), which contains information on potential destinations for reuse/recycling of gasification solids.

RESPONSE

Applicant has submitted the requested information confidentially.

DATA REQUEST

99. Please provide under confidential cover Applicant's 2009 Response to CEC Data Request No. 28, Table 28-1, which contains information on potential customers for degassed liquid sulfur.

RESPONSE

Applicant has submitted the requested information confidentially.

BACKGROUND: DEMONSTRATION OF COMPLIANCE OF COMMISSIONING EMISSIONS WITH 1-HOUR NO_2 NATIONAL AMBIENT AIR QUALITY STANDARD

The AFC states that impacts from NOx emissions during commissioning activities were not modeled for comparison against the 1-hour NO_2 national ambient air quality standard ("NAAQS") due to "the short duration… and the statistical nature of the NO_2… NAAQS." (Modeling Protocol Supplement for the Hydrogen Energy California (HECA) Project, February 21, 2012, p. 8.) However, Clean Air Act regulations and recent guidance by the U.S. EPA states that compliance with the 1-hour NO_2 NAAQS should be assessed for "sources that occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." (U.S. EPA, *Additional Clarifications Regarding Application of Appendix W Modeling Guidance for 1-hour NO_2 NAAQS*, from Tyler Fox, Office of Air Quality Planning and Standards, March 1, 2011). Project commissioning is expected to occur over 16 months, *i.e.*, longer than one year. (*See*, *e.g.*, AFC, p. 5.1-25.) Therefore, following the U.S. EPA's guidance, maximum hourly NOx emissions from Project commissioning should be modeled and predicted impacts should evaluated for compliance with the 1-hour NO_2 NAAQS. For example, the recent AFC for the Quail Brush Generating Project in San Diego County evaluated compliance of commissioning emissions with the 1-hour NO_2 NAAQS.[1]

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[1] *See* http://www.energy.ca.gov/sitingcases/quailbrush/documents/applicant/afc/Volume%201/Section%204%207%20Air%20Quality.pdf.

DATA REQUEST

100. Please evaluate compliance of Project commissioning emissions with the 1-hour NO_2 NAAQS.

RESPONSE

Commissioning is completed by system starting with the feed-producing units and ending with the product-producing units. Not all systems will be commissioned simultaneously, and once a system is commissioned it will operate in normal mode. This means that during each step in commissioning, not all sources will operate and many will operate with normal emission rates. Thus, the emissions from each source in commissioning mode are intermittent and would not occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations over a 3-year period.

As noted in the modeling protocol submitted in February 2012, the technique for modeling commissioning emissions was presented and approved by all reviewing agencies, United States Environmental Protection Agency (USEPA) Region IX, San Joaquin Valley Air Pollution Control District (SJVAPCD), and CEC.

BACKGROUND: PREDICTED LOCATIONS OF MAXIMUM POLLUTANT CONCENTRATIONS

The AFC, Figure 5.1-3, and the ATC/PSD Permit Application, Figure 4-3, show that the maximum NO_2 ground level concentrations (1-hour and annual NAAQS) and the maximum predicted annual $PM_{2.5}$ and PM_{10} ground level concentrations are predicted to be co-located along the eastern boundary of the Project site. This identical location of the maximum predicted NO_2 and PM_{10}/$PM_{2.5}$ concentrations is unusual because the Project's operational NOx emissions are emitted from combustion sources with high plume rise (*e.g.,* heat recovery steam generator/ combustion turbine generator and coal dryer). In contrast, less than 70% of the Project's operational PM_{10} emissions and less than 80% of its $PM_{2.5}$ emissions are emitted from combustion sources; the remaining PM_{10}/$PM_{2.5}$ emissions are emitted from the Project's wet cooling towers and from fugitive dust sources. Based on the various release heights, plume rise, and locations of the emission sources, the maximum ground level concentrations of NO_2, PM_{10}, and $PM_{2.5}$ would usually occur at different locations. The predicted identical location of the modeled pollutant locations is therefore questionable.

The maximum NO_2 (1-hour and annual California ambient air quality standards ("CAAQS")) and 1-hour CO ground level concentrations are also predicted to occur along the eastern boundary of the Project site. The proximity of all these locations for different pollutants and averaging times raises questions about the validity of the modeling results.

DATA REQUEST

101. Please verify all modeling inputs, especially source emissions and stack parameters, for the AERMOD modeling of maximum pollutant concentrations resulting from Project operational emissions.

- ***a. If all modeling inputs are determined to be correct, please provide a discussion explaining the unusual occurrence of the maximum predicted ground level concentrations of various pollutants at the same location and along the eastern boundary of the Project site.***
- ***b. If modeling inputs are determined to be incorrect, please re-run the AERMOD model and provide updated modeling results and discussions.***

RESPONSE

a. The modeling inputs are correct. It is typical for maximum pollutant concentrations to occur near to each other along a project boundary. In this case, all of the maximum predicted concentrations occurring along the eastern edge of the Controlled Area are due to two main reasons. The first and most important is that the dominant wind direction is from the west, as shown in the windroses in Appendix E-1 of the Amended AFC. The hourly meteorological data set has more westerly winds than any other direction; therefore, the plumes are more likely to affect receptors to the east of the Project site. The second reason is that boundary receptors are the first receptors that low level plumes intersect before the plumes are dispersed as they travel farther from the source. The majority of the sources that contribute to the maximum pollutant concentrations on the eastern boundary are from sources with stack parameters that result in less plume rise.

b. Please see the response to Data Request 101a.

DATA REQUEST

102. Please provide isopleths of ground level concentrations for each pollutant and source contributions.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

DATA REQUEST

103. The Project's heat recovery steam generator ("HRSG") is the largest source of Project operational NOx emissions (109.7 tons/year of a total of 163.7 tons/year), yet this source does not appear to contribute to the maximum predicted NO_2 ground level concentrations. The HRSG has very high plume rise, about 300-400 m according the SCREEN3 modeling provided in the AFC, and therefore its emissions should rise above the maximum receptor at the eastern boundary where the maximum NO_2 ground level concentrations were determined.

a. Please verify the stack parameters (height of 213 feet, stack diameter 23 feet) for the HRSG and provide supporting documentation.

b. Please quantify the contribution of the HRSG to the predicted maximum NO_2 ground level concentrations as modeled.

c. In the modeled scenario, the HRSG is operating at less than full load. Please provide a) a modeling run where the HRSG is operating at 100% load to assess the maximum predicted ground level NO_2 concentrations from this source and b) a modeling run where the HRSG is operating at 100% load in addition to the intermittent sources.

RESPONSE

a. The stack height of 213 feet for the HRSG can be found in Figure 2-6 *Project Elevations* of the Amended AFC. Stack parameters are provided in Amended AFC, Appendix E-3, on page 22 of 33, which also confirms the HRSG stack height of 213 feet and the diameter of 23 feet.

b. At the location of the maximum predicted NO_2 modeled concentration from all HECA sources for each standard, the peak HRSG concentration is listed below. For the 1-hour standards, the peak concentration from the HRSG at this location may not occur during the same hour as the maximum concentration from all sources.

Pollutant and Standard	HRSG Contribution to Modeled Concentration ($\mu g/m^3$)
NO_2 1-hour CAAQS	44
NO_2 1-hour NAAQS SIL	11
NO_2 Annual CAAQS	0.22
NO_2 Annual NAAQS	0.28

c. a) An important aspect to remember about dispersion modeling is that when a source is operating at 100% load, or even when a source is operating with maximum emissions, those operating scenarios may not necessarily correspond with the source's maximum ground level impact. This is further described in *Modeling Scenarios*, Section 5.1.2.5 of the Amended AFC. Lastly, different operating equipment usually have individual maximum predicted concentrations occurring at different locations. The maximum predicted concentration for each pollutant from an entire facility, and its corresponding location, is dependent on *all* sources combined.

b) The maximum NO_2 NAAQS and CAAQS impact scenarios for all HECA operating equipment, which include intermittent sources, are described in Section 5.1.2.5 of the Amended AFC. The modeling results from project operations may also be found in the Amended AFC, Section 5.1.2.6, *Compliance with Ambient Air Quality Standards.*

BACKGROUND: MONITORING STATION FOR AMBIENT NO_2 CONCENTRATION DATA

The Applicant's AERMOD modeling for 1-hour NO_2 concentrations uses meteorological data from the Bakersfield Airport meteorological station (AFC, p. 5.1-40) and ambient ozone and NO_2 concentration data measured at the Shafter-Walker Street Station monitoring station (AFC, p. 5.1-5). Yet, the Bakersfield monitoring station at 5558 California Avenue is located considerably closer to the Bakersfield airport than the Shafter–Walker Street Station monitoring station and also provides 1-hour NO_2 concentration data.[2] Figure 1 of the NO_2 Modeling Report, p. 27, shows that the Bakersfield 5558 California Avenue monitoring station is located only 6 miles south of the Bakersfield Airport, while the Shafter–Walker Street Station monitoring station is located about 13 miles northwest of the airport. Thus, ambient hourly pollutant measurements at the Bakersfield 5558 California Avenue monitoring station are more consistent with meteorological data from the Bakersfield airport than those from the Shafter–Walker Street Station monitoring station. The NO_2 Modeling Report also indicates that one of the primary reasons for selecting the Shafter monitoring station as opposed to any other station is the contribution of mobile source emissions that are not reflected in the regional inventory. However, Figure 1 of the NO_2 Modeling Report shows that both the HECA Project and the Bakersfield 5558 California Avenue monitoring station are located near major highways (about 3 miles from Interstate 5 to the HECA Project site and about 1 mile from the junction of Highways 99 and 58 to the Bakersfield 5558 California Avenue monitoring station), while the Shafter–Walker Street Station monitoring station is located 6 miles west of Highway 99. Due to its location, contributions from mobile sources are therefore not adequately reflected in the monitoring data from the Shafter-Walker Street Station monitoring station.

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[2] *See* http://www.epa.gov/airdata/ad_rep_mon.html.

DATA REQUEST

104. Please explain why data from the Bakersfield 5558 California Avenue monitoring station are not considered more representative than data from the Shafter-Walker Street Station monitoring station for purposes of 1-hour NO_2 modeling given the greater proximity of the Bakersfield 5550 California Avenue monitoring station to the HECA Project site, the Bakersfield Airport meteorological station and mobile source emissions from free/highways.

RESPONSE

An explanation of the selection of the ambient ozone and NO_2 data used in the NO_2 modeling was provided in the response to Data Request 5, in *Responses to AIR Data Requests, Nos. 1 through 11,* July 2012, and also in the background data discussion in Appendix E-7, NO_2 1-Hour Regional Analysis, of the HECA Amended AFC.

DATA REQUEST

105. Please update the 1-hour NO_2 modeling for the Project's operational emissions to reflect 1-hour NO_2 data collected at the Bakersfield 5558 California Avenue monitoring station.

RESPONSE

As discussed in the response to Sierra Club Data Request 104 and response to AIR Data Request 5, the O_3 and NO_2 data selected for the NO_2 modeling are appropriate, thus modeling will not be updated with any other data.

BACKGROUND: BOILER STARTUP EMISSIONS

The Applicant states that during startup, before the selective catalytic reduction ("SCR") system has reached its optimal operating temperature, the auxiliary boiler would emit NOx at a rate of 0.06 pounds per million British thermal units ("lb/MMBtu"). The Applicant estimates that the boiler would emit at that rate for four hours per startup with two startups per year, resulting in total NOx emissions of 20.45 pounds per year during startup operations. (Responses to Sierra Club Data Requests Nos. 50 and 51.) The Applicant did not provide how it arrived at this estimate, but it appears to be based on the assumption that the auxiliary boiler operates at 42.6 lb/MMBtu during startup, *i.e.*, one fifth of its maximum heat capacity of 213 MMBtu/hr.[3]

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[3] (213 MMBtu/hr) / (42.6 MMBtu/hr) = 0.2.

DATA REQUEST

106. Please discuss and provide support why the auxiliary boiler was assumed to operate at one fifth of its maximum heat capacity during startup before the SCR system has reached its optimal operating temperature.

RESPONSE

The auxiliary boiler needs up to 4 hours to reach SCR's operating temperature. The estimated heat release for this operation corresponds to the minimum stable load for the boiler during warm-up. Once the auxiliary boiler reaches operating temperature, it will operate throughout its emissions compliant load range as necessary to support plant startup activities.

BACKGROUND: EMISSIONS FROM CO_2 VENT

The Project's carbon dioxide ("CO_2") vent stack would allow for startup and emergency venting of produced CO_2 when the CO_2 compression, transportation, or injection system is unavailable. (AFC, p. 5.1-21.) In addition to CO_2, the vented gas would contain hydrogen sulfide ("H_2S") and carbonyl sulfide ("COS"), which are both hazardous air pollutants ("HAPs"), carbon monoxide ("CO"), and volatile organic compounds ("VOCs"). (AFC, Appx. E-3, p. 10.) The AFC provides estimates for emissions of these pollutants from the CO_2 vent in Appendices E-3 and M. The AFC fails to provide adequate documentation to verify its emission estimates, some of which appear problematic.

DATA REQUEST

107. Please provide a copy of the "Plant Performance Study" cited as the source for assumptions of total flow (in lb/hour, lb-mol/hour); CO_2 flow to pipeline (in tons CO_2 /hour); and concentrations of H_2S, COS, CO, and VOCs (in ppmv) used to estimate emissions of COS, H_2S, CO, and VOCs from the CO_2 vent, if necessary under confidential cover.

RESPONSE

The Plant Performance Study referenced in the Amended AFC for this emission source is for a similar, previous project and no longer applies. It has been superseded by the process design package from the Rectisol technology licensor selected specifically for the current HECA project configuration. The updated Rectisol process is designed to operate within the emission limits proposed in the Amended AFC, including trace components in the contingency CO_2 vent. It is important to note that the primary purpose of the contingency CO_2 vent is to allow correction of short-term disruptions in the CO_2 transportation and receiving systems while avoiding the additional emissions associated with a complete plant shutdown and restart and loss of production. Plant startup and shutdown emissions are accounted for in the Amended AFC and subsequent submittals.

The information in the Rectisol process design package is covered by a non-disclosure agreement (NDA) and for this reason the Applicant is prohibited from disclosing it to other parties.

DATA REQUEST

108. Please provide, if necessary under confidential cover:

a. A detailed discussion of how the concentrations of 10 ppmv COS, 10 ppmv H_2S, 1000 ppmv CO, and 40 ppmv VOCs in the CO_2 vent gas were determined including a discussion of the projected concentration range for each pollutant, an identification of the individual compounds accounted for in the VOC concentration, and adequate documentation to support your discussion and calculations.

b. A detailed discussion of how the total flow and the CO_2 flow to pipeline were determined. Please support your discussion and calculations with documentation.

c. A detailed discussion of how the projected 21 days of CO_2 vent operations (2 cold start-ups of the gasification block with a duration of 3 days per event; 4 unplanned outages of the CO_2 compressor lasting 2 days per event; 1 unplanned outage of the CO_2 pipeline lasting 1 day; and 2 events when the CO_2 off-taker is unable to accept CO_2 with a duration of 3 days per event) were derived. (AFC, Table 5.1-21, p. 5.1-96.)

d. If any of the above requested information was provided by the manufacturer rather than calculated, please provide the respective documentation.

RESPONSE

a. These concentration values are based on the technology licensor's proprietary Rectisol simulation model and their expertise in process design to meet the proposed emission limits. The values stated in the Data Request are guaranteed maximum short-term concentrations. The actual emissions are expected to be less. The sole component of VOC is residual, trace methanol, the solvent for the Rectisol process that selectively absorbs sulfur and CO_2 from the syngas. Because the supporting documentation is covered by the same NDA referenced in the response to Data Request 107, the Applicant cannot provide it to other parties.

b. The CO_2 flow to the sequestration pipeline is based on the project carbon balance as documented by the Applicant's response to CEC Data Requests A14 and A15. The total pipeline flow and the CO_2 flow are essentially the same, since the product CO_2 is over 97 percent pure.

c. The combination of events described in the Amended AFC for establishing the proposed maximum annual venting period is only one of a number of plausible scenarios that might lead to this duration. The 21-day annual venting limit was selected to provide a conservative and reasonable time to correct delivery disruptions and to avoid the environmental emissions associated with plant shutdown and restarting.

d. The requested documentation for (a) above is covered by a NDA and cannot be disclosed by the Applicant.

DATA REQUEST

109. The AFC indicates that the VOC emitted with the CO_2 vent gas stream (concentration 40 ppm) is "MeOH", which is the commonly used abbreviation for methanol. (AFC, Appx. E-3, p. 10.) Methanol is both a VOC and HAP. The AFC estimates VOC emissions from the CO_2 vent gas at 11 lb/hour and 2.8 ton/year (as CH4, i.e., methane). (Ibid.) However, the AFC fails to estimate emissions of methanol from the CO_2 vent for purposes of determining HAP emissions from the Project. (See AFC, Appx. M, p. 1.) Based on the AFC's estimates for VOC emissions (as CH4), HAP emissions from the CO_2 vent can be estimated at 5.6 ton/year (as MeOH).[4] This increases the estimate of total methanol emissions from the Project from 7.09 tons/year to 12.69 tons/year, which exceeds the 10 ton/year major source threshold for emissions of single HAPs pursuant to 40 CFR §63.41 (defining a major source as a facility that will emit 10 tons annually of any HAP or 25 tons annually of any combination of HAPs.)

a. Please revise estimates for HAP emissions from the Project to account for methanol contained in the CO_2 vent gas.

b. Please revise the health risk assessment for the Project to account for emissions of methanol contained in the CO_2 vent gas.

c. Please provide a case-by-case maximum achievable control technology ("MACT") analysis pursuant to 40 CFR Part 63, Subpart B for the Project's emissions of HAPs.

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[4] (2.8 tons VOC as CH_4/year) × (methanol = CH_3OH: 32 lb/lb-mol) / (methane = CH_4: 16 lb/lb-mol) = 5.6 tons VOC as CH_3OH/year.

RESPONSE

As described in *Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2*, docketed on November 19, 2012, the Applicant is requesting additional time to address this Data Request.

DATA REQUEST

110. The AFC estimates for annual emissions from the CO_2 vent are based on CO_2 vent gas concentrations of 10 ppmv COS, 10 ppmv H2S, 1000 ppmv CO, and 40 ppmv VOCs. (AFC, Appx. E-3, p. 10, and Appx. M, p. 10.) The emission estimates from the CO_2 vent in the prior proceedings for the HECA project used the same H_2S, CO, and VOCs vent gas concentrations but a considerably higher COS vent gas concentration of 55 ppmv. (08-AFC-08, Appx. D, p. 45, and Appx. N, p. 11.)

a. Please explain and document why the projected COS concentration in the Project's CO_2 vent gas under the current configuration would be less than one fifth of that determined for the prior plant configuration even though H_2S, CO, and VOCs concentrations are the same.

RESPONSE

a. As documented in Section 2 of the Amended AFC, the disposition of the Sulfur Recovery Unit (SRU) tail gas has changed from the prior HECA project. In the previous project the SRU tail gas, comprised of mainly CO_2 plus residual unconverted H_2S and SO_2 with by-product COS, was sent to a conventional Tail Gas Treating Unit. In this unit SO_2 in the tail gas was hydrogenated to H_2S, and the total H_2S in the treated tail gas was almost completely removed in an amine absorber. The relatively small amount of vent gas from this absorber, containing CO_2, COS, and a minor amount of unabsorbed H_2S, was then blended with the much larger product CO_2 stream for sequestration in the Elk Hills Oil Field. Therefore, if it became necessary to vent the CO_2 product gas, the Tail Gas Treating vent gas, including the trace COS, would be present in this stream.

The current project utilizes an innovative SRU tail gas treatment scheme whereby the tail gas is hydrogenated and recycled by blending with the syngas feed to the Sour Gas Shift Unit. In the current design, the COS from the SRU tail gas is not blended with the product CO_2 and will not be present if it is necessary to vent product CO_2. Thus, the COS in the current CO_2 contingency vent is considerably less than before.

BACKGROUND: COMPLIANCE WITH MERCURY AND AIR TOXICS STANDARDS

Sierra Club Data Requests Nos. 82 and 83 established that the Project may not be able to demonstrate compliance with the mercury ("Hg") emission standard of 3.03E-03 pounds per Gigawat-hour ("lb/GWh") established in the U.S. EPA's recently promulgated mercury and air toxics standards ("MATS"). The Applicant objected to the objected to Data Request No. 82 (to provide a quantitative analysis of the Project's emission rates of particulate matter ("PM") or surrogate, Hg or surrogate) and Data Request No. 83 (discussion of how the Project would demonstrate compliance with the MATS emission limits) "on the basis that the referenced standard has been stayed and is being reassessed and may no longer be applicable." Yet, the Applicant's May 2012 *Authority to Construct (ATC) Permit Application and Supplemental Information for the Prevention of Significant Deterioration (PSD) Permit Application* submitted to the San Joaquin Valley Air Pollution Control District ("SJVAPCD" or "District"), p. 6.4-1, states that "… USEPA promulgated a new NESHAP for both major HAPs and area sources for IGCC EGUs that limits emissions of mercury, hydrogen chloride, and filterable particulate matter" and claims that "*Emissions of these pollutants from the HECA Project will comply with this standard*." (*Emphasis* added.)

DATA REQUEST

111. Has the Applicant notified the SJVAPCD that the Project in its current configuration would emit mercury in excess of the 3.03E-03 lb/GWh standard established under MATS? If the answer is no, please notify the District.

RESPONSE

HECA will comply with the proposed mercury and air toxics standards (MATS) and has shown how it will comply in the response to CEC Data Request A135 provided in October 2012. This response was also provided to SJVAPCD.

DATA REQUEST

112. Has the Applicant notified the SJVAPCD that it no longer considers the MATS standard applicable on the basis that the standard has been stayed? If the answer is no, please notify the District.

RESPONSE

As noted in the response to Data Request 111, HECA has shown how it will comply with the proposed MATS in the response to CEC Data Request A135 and provided this information to SJVAPCD.

BACKGROUND: FUGITIVE ENTRAINED ROAD DUST EMISSIONS FROM ON-SITE MOBILE SOURCES

Fugitive entrained road dust particulate matter emissions from on-site mobile sources must be included in the potential to emit ("PTE") of a major source (40 CFR 52.21(b)(1)(iii)) and therefore in the modeling for compliance with ambient air quality standards. The AFC appears not to include fugitive particulate matter emissions in the emission calculations and, consequently, in the modeling for the Project. (*See* AFC, Table 5.1-14, p. 5.1-83.)

DATA REQUEST

113. Please revise the Project's PTE to include on-site PM_{10} and $PM_{2.5}$ emissions from fugitive entrained road dust.

RESPONSE

Fugitive dust emissions from on-site mobile sources are presented in Table 5.1-20 and Appendix E-3 of the Amended AFC for Alternative 1, and Table 5.1-31 and Appendix E-12 of the Amended AFC for Alternative 2. These emissions were included in the modeling as described in Section 5.1.2 of the Amended AFC.

DATA REQUEST

114. Please revise ambient air quality modeling for compliance with PM_{10} and $PM_{2.5}$ CAAQS and NAAQS to account for on-site PM_{10} and $PM_{2.5}$ emissions from fugitive entrained road dust.

RESPONSE

Road dust emissions were included in the modeling as outlined in Section 5.1.2 of the Amended AFC and the February 2012 Modeling Protocol Supplement, which was approved by all reviewing agencies, USEPA Region IX, SJVAPCD, and CEC. Modeling results for PM_{10} and $PM_{2.5}$ may be found in Table 5.1-27 of the Amended AFC.

BACKGROUND: SITING ALTERNATIVES TO PREVENT LOSS OF PRIME FARMLAND

The Project will convert 453 acres of prime farmland, under a Williamson Act contract, to non-agricultural use.

DATA REQUEST

115. Did the Applicant consider siting the facility on the Elk Hills oil field to prevent loss of prime farm land, reduce impacts on local residents, etc.?

RESPONSE

Yes, the Applicant did consider siting the facility in the Elk Hills Oil Field. As indicated in Section 6.3 of the Amended AFC, the current project Site was selected based upon, among other considerations, the available land; proximity to a CO_2 storage reservoir; and the existing natural gas transportation, electric transmission, brackish groundwater supply, rail, and roadway infrastructure that could support the Project.

HECA's initial AFC (08-AFC-8) was submitted to CEC on July 30, 2008, which proposed the Project on a different site south of the California Aqueduct and adjacent to the Elk Hills Oil Field. The Project was subsequently moved when it was discovered that previously undisclosed sensitive biological resources existed at this original site. As a result, HECA was required to conduct an alternative site analysis that was not merely theoretical, but was in fact necessary to identify an alternative site for the Project, which has now become the Project Site.

BACKGROUND: FLARE EMISSIONS DURING MALFUNCTIONS

The Applicant's Supplemental October 2012 Responses to Sierra Club Data Requests Nos. 62 and 63, p. 62-1, claim that there will be no malfunction events and therefore no flare emissions associated with malfunction events: "The Amended AFC presents emissions from each flare, incorporating anticipated startups and shutdowns. Given the reliability of the subject equipment, there are no anticipated malfunctions; therefore, no emissions associated with such events are included in the PTE." The most similar integrated gasification combined cycle ("IGCC") facility to HECA, the Nakoso IGCC facility in Japan, experienced availability of 30 percent in Year 1 and 60 percent in Year 2, only marginally better in its first two years of operation than IGCC plants that have been operational for nearly 20 years, *e.g.,* the Tampa Electric Polk Power Station in Polk County, Florida, and the Wabash River Coal Gasification Repowering Project near West Terre Haute, Indiana.[5] The low availability is due in part to forced outages (aka malfunctions).

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5 Electric Power Research Institute; John Wheeldon, IGCC 101, Advanced Coal Gasification Technologies Workshop, Kingsport, 25th & 26th April 2012; http://www.gasification.org/uploads/downloads/Workshops/2012/Wheeldon,%20Kingsport.pdf.

DATA REQUEST

116. Please explain the basis for the assertion that there will be no malfunction flaring emissions at HECA and provide supporting documentation.

RESPONSE

HECA expects to perform a plant-wide shutdown for annual maintenance on all equipment once per year during the offpeak power demand season. The frequency and duration of this annual shutdown is set by the annual maintenance expected in the gasification and combustion turbine areas. Part of the decision to use Mitsubishi Heavy Industries (MHI) gasification unit technology is due to the higher expected reliability provided by the membrane wall and other design elements. Even though the gasifier is expected to run a full year between maintenance outages, an additional complete plant-wide shutdown and startup was included in the Amended AFC emissions estimates to accommodate unplanned equipment issues. Additionally, the Amended AFC included additional annual CO_2 vent emissions over the life of the project to accommodate the expected reliability of the CO_2 compression and transportation systems.

With the support of the Japanese utility industry and government, MHI designed and constructed a full scale, 250 MW (1700 tonnes/day), IGCC plant at Nakoso Japan. The design of the Nakoso plant began in 2001 and construction was completed in 2007. Except for a 4.5-month shutdown period following the 2011 earthquake and tsunami, this plant has been operating continuously (except for scheduled maintenance and inspection) on a wide range of coals from around the world. The Nakoso Plant has provided valuable data, high operating reliability, fast start-up times, plant flexibility, and emissions performance.

It is important to note that the Nakoso plant has also been shut down for long periods for inspection, and this was part of the technology development providing important information to MHI on design elements. Nakoso has completed a 5,000 hours reliability run and two separate continuous operating periods of over 2,000 hours (scheduled test period) each. Cumulative operating hours since commissioning has exceeded 16,100 hours (as of April 2012). The Nakoso plant is running today as a commercial power plant being dispatched to meet the demand for power in the local market.

The HECA Project permit applications account for all planned flaring events, including temporary flaring during unit startup and shutdown operations. Additional flaring has also been accounted for during the initial startup commissioning activities following construction. HECA has designed the plant so that no flaring will occur during normal plant operation. Based on the project design, and the operating experience at the Nakoso plant, no malfunction flaring events are expected.

DATA REQUEST

117. Please discuss the claimed reliability of the Project's equipment, and the claim that no malfunctions will occur, given the Project incorporates process equipment and design that have never been used (or used in the proposed combination) before including: a) the Project's gasifier which so far has only been demonstrated on a pilot scale, b) the incorporation of CO_2 compression for discharge to a CO_2 pipeline, and c) the incorporation of a fertilizer manufacturing complex.

RESPONSE

Please see response to Data Request 116.

DATA REQUEST

118. Please provide examples of any operational IGCC facilities in the world that have demonstrated continuous operation with no malfunction emissions over a period of at least a year.

RESPONSE

Applicant does not have information that correlates malfunction emissions for any IGCC plant. Also refer to the response to Sierra Club Data Request 61.

BACKGROUND: FLARE DESIGN

Sierra Club's prior data requests (55 through 58) pointed to two IGCC facilities (PureGen, Stanton Unit B) which were designed with enclosed ground flares. The Applicant's responses to Sierra Club's Data Requests No. 55 through 58 cite to the "inherently safer design" of elevated flares compared to enclosed ground flares.

DATA REQUEST

119. Please provide documentation that shows the design of elevated flares is "inherently safer" compared to enclosed ground flares.

RESPONSE

While both elevated flares and totally enclosed ground flares are capable of combusting the types of gases used in the HECA project, there are significant differences between the two flare system types that lead to one or the other being preferred for a specific application. It is also important to consider the type of gases that are being combusted. For example, refinery gases typically contain mostly low molecular weight volatile organic compounds (VOCs), including olefins. The flames produced by refinery gases are typically very luminous, generate high amounts of radiant heat and have a tendency to smoke without steam or air assistance. In contrast, gases from HECA have a much higher hydrogen to carbon ratio and the flames are much less luminous. HECA gas compositions do not require steam assist or other techniques for smokeless operation. Ground flares are often selected when plot space is limited and where the radiant energy from an elevated flare requires a large exclusion zone (where equipment and personnel access is prohibited during operation). As such, the use of a totally enclosed ground flare does not have any significant advantages for the HECA project and in fact has significant disadvantages.

The petroleum and chemical industries use the term "inherently safer" to describe systems that rely on passive protections rather than highly instrumented systems or systems that require operator intervention to be safe. The elevated flare system is considered inherently safer for the HECA project application for the following reasons:

- The totally enclosed ground flare requires multiple burner stages. Each stage requires its own control valve, pilot burner and flame detection system. The control valves could potentially fail closed and then would be bypassed by rupture disks. The rupture disks provide a path to the burners if one or more of the valves fail to open. However, the rupture disk and valve that failed would require maintenance to restore proper operation of the flare system.

- The totally enclosed ground flare is not actually "totally enclosed." The combustion air is supplied at the base of the flare which is surrounded by a "wind fence," typically only about 20 feet high. So the ground flare can be an ignition source under some circumstances.

- The ground flare combustion chamber, or stack, would typically be 140 feet or somewhat higher. The elevated flare tip on HECA is at least 250 feet. The elevated flare height assures better dispersion if for some reason the flare fails to ignite. This is particularly important for gases that could be more dense than air. These gases would exit the elevated flare at 250 feet versus the potential to flow over the top of a 20-foot-high wind fence on a ground flare.

- Totally enclosed ground flares require internal insulation or refractory lining which can fail in operation.
- There is far more experience using elevated flares for the medium BTU gases generated by gasification plants such as would be used at HECA.

References:

Air Pollution Control Technology Fact Sheet (EPA-452/F-03-019).

Flare Details for General Refinery and Petrochemical Service [ANSI/API Standard 537, Second Edition, December 2008].

Pressure-relieving and Depressuring Systems [ANSI/API Standard 521 Fifth Addition, January 2007, Addendum, May 2008].

DATA REQUEST

120. Please provide specific instances where the presence of an enclosed ground flare at an existing refinery or petrochemical facility created a safety hazard and how that safety hazard was resolved.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

DATA REQUEST

121. Please confirm that URS presented an enclosed ground flare as BACT for the proposed Pacific Northwest Energy Center IGCC plant in 2006, and prepared the hazardous air pollutant emissions estimate for the enclosed ground flare.

RESPONSE

The Pacific Mountain Energy Center proposed to install an elevated enclosed flare as part of the gasification block. Hazardous air pollutant emissions from the flare were included in the Energy Facility Site Evaluation Council (EFSEC) application.

DATA REQUEST

122. Please provide the safety history of Ground Flare 65F-8 at the ExxonMobil Torrance (CA) Refinery.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

BACKGROUND: COST OF WATER SUPPLY SYSTEM, COOLING TOWERS, AND ZERO-LIQUID DISCHARGE SYSTEM

The overwhelming majority of the HECA raw water demand is associated with the three HECA cooling towers, either to replace evaporative losses in the cooling towers or to replace blowdown from the cooling towers. The raw water will be supplied to HECA from five groundwater pumping wells on Buena Vista Water Storage District ("BVWSD") land and delivered to HECA via a 15-mile, 20-inch pipeline. This raw water will be treated onsite at HECA in a raw water treatment plant, then directed to three onsite cooling towers. Blowdown from the cooling towers will be directed to a zero discharge ("ZLD") system. The capital and operation and maintenance ("O&M") costs associated with the raw water treatment and ZLD equipment are either primarily or exclusively due to the proposed use of wet cooling towers at HECA.

DATA REQUEST

123. Please discuss whether HECA will be responsible for capital and O&M expenses related to: a) the five groundwater pumping wells on BVWSD land, b) the 15-mile pipeline from the wells to HECA, and c) all O&M expenses associated with pumping and transport. Please provide documentation to support your response.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

DATA REQUEST

124. Please confirm that HECA will be paying $450 per acre foot for the raw BVWSD water and provide supporting documentation.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

DATA REQUEST

125. Please confirm that HECA will be paying for all O&M, power, and replacement costs ("OMP&R") associated with BVWSD sale water and necessary related facilities.

RESPONSE

As described in Applicant's Objections and Requests for Additional Time to Respond to Sierra Club's Data Requests Set 2, docketed on November 19, 2012, the Applicant objects to this Data Request.

DATA REQUEST

126. Please confirm that approximately 86 percent of the water usage at HECA is associated with the three HECA cooling towers at 65 F ambient temperature. (AFC, Figure 2-10.) Provide the percentage of water usage associated with the three HECA cooling towers at 80 F, 90 F, and 100 F.

RESPONSE

The Applicant confirms the accuracy of Amended AFC Figure 2-10, Water Usage, which shows that approximately 83 percent (i.e., 36 percent + 36 percent + 11 percent) of the water usage at 65°F is associated with the three cooling towers. As shown in Amended AFC Figure 5.14-13, Mass Water Balance, approximately 85 percent [i.e., (3,779 gpm + 569 gpm)/5,133 gpm = 84.7 percent)] of the water usage at 97°F is associated with the three cooling towers. The trend seen between 97°F and 65°F continues for all ambient temperatures. As the ambient temperature gets cooler, the absolute quantity of water used and the portion of water used for the cooling towers both go down.

DATA REQUEST

127. Please fill-in the table below and provide the total capital costs, energy costs, and O&M costs associated with all elements of the water supply system providing water to the three onsite cooling towers, including: the five water wells in the BVWSD service territory, the 15-mile pipeline from these wells to the Project, the raw water treatment plant, the three cooling towers, and the ZLD system, and any other facilities or equipment that may be required.

Element	Capital Cost ($MM)	Energy/ Delivery Cost ($/year)	Non-Energy O&M Cost ($/year)
Five groundwater extraction wells (7,500 AFY)			
15-mile pipeline from wells to HECA			
Raw water		7,500 x $450	
Raw water OMP&R rate O&M, power, replacement			
Raw water treatment plant			
Power block cooling tower			
Process cooling tower			
Air separation unit cooling tower			
ZLD processing plant			
Other facilities or equipment related to the cooling towers or water treatment or disposal			

RESPONSE

The background section of this data request discusses the routine use of air cooled condensers for Natural Gas Combined Cycle (NGCC) plants in California and Nevada. The cost information that is requested might be useful for comparing the costs of wet cooling versus dry cooling in the context of a NGCC, and in fact similar analyses have been performed for other CEC permitted NGCC plants. However, in the case of an Integrated Gasification Combined Cycle (IGCC) plant with CO_2 capture and chemical co-production, the differential in capital and O&M costs is a relatively minor consideration compared to the output and efficiency penalties.

In a typical NGCC plant about one-third of the gross power output is generated by the steam turbine and the other two-thirds is generated by the gas turbine. NGCC plants in California and Nevada typically use evaporative cooling to chill the inlet air to the gas turbine which increases gas turbine output on hot days. Using air cooled condensers in NGCC plants does impose a substantial output penalty on the project that is most pronounced on hot days. However, the penalty is only on the steam turbine output which may make the choice economically feasible.

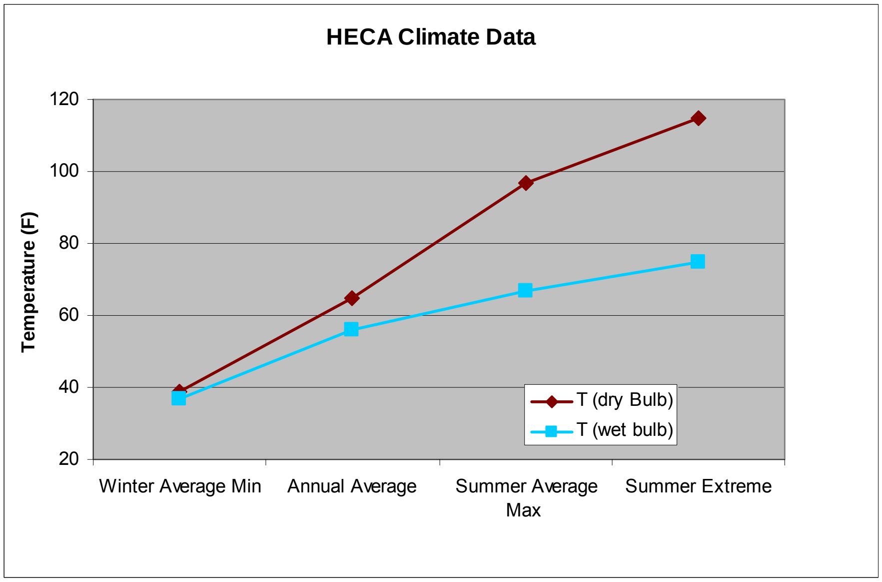
The output, cost, and efficiency penalties associated with using only air cooling are much more significant for the HECA project than for a typical NGCC project. This is because for an NGCC, the efficiency impact is confined to the steam turbine whereas in process units (gasification, gas treatment, and manufacturing complex) the impacts occur to many pieces of equipment, most of which are significantly more sensitive to heat rejection temperature than the steam turbine.

Air cooling was not selected because it results in a substantial increase in parasitic electrical demand and a dramatic decrease in power output. These effects result in a markedly negative impact on the cost and availability of electricity. Just for the combined cycle portion of the facility alone, comparison to CEC studies would indicate that the efficiency loss results in reduced power output of over 15 MW.

The efficiency loss (increase in auxiliary load) and capital cost impacts associated with implementing air cooling within the process portion of the plant is real and large but much more pervasive and difficult to quantify than in the power block. The loss of revenue caused by a lower net power output is large and would outweigh any net capital cost change. While this data request asks for specific information about capital and O&M costs, that information is not available without an extensive detailed engineering study. Determining the capital, O&M and auxiliary power impacts would require a complete redesign and cost estimate of the facility. Each piece of equipment that requires cooling must be looked at and changes made to address the process, hydraulics, equipment location and other aspects of the basic configuration that are needed. This is because air cooling imparts both a higher heat rejection temperature that is available to the process and proximity and space constraints that impact plot configuration and process hydraulics. As an example, a multistage compressor would likely require additional stages of compression and changes in plot location to accommodate air cooling. This would require additional energy consumption and operating complexities that have not been considered. Most importantly, even if this information were available, it is really the efficiency loss that drives the economic impacts. In addition to being economically unsound the use of dry cooling would be environmentally undesirable as benefits for the BVWSD would not be achieved. See response to A.I.R. Data Request 14 for further description of these benefits.

From a thermodynamic point of view, air cooling requires the heat rejection temperature to be above the ambient dry bulb temperature. Using mechanical draft cooling towers allows the heat rejection temperature to be somewhat above the ambient wet bulb temperature. As indicated in Figure 127-1, an additional 30 to 40 degrees of temperature driving force is available using water cooling because the difference between the dry bulb temperature and the wet bulb temperature is much higher on hot summer days than the annual average day. Since the need for power and the price for power is much higher on hot summer days, the loss in power output comes precisely when it is most valuable and needed in the California Independent System Operator (CAISO) grid. The process areas associated with an IGCC have many pieces of equipment as compared to a power block which only has a final condenser serving the steam turbine generator. Figure 127-1 illustrates how the heat rejection temperature penalty for air cooling increases on hot days.

Figure 127-1
HECA Climate Data



BACKGROUND: COST ESTIMATE FOR AIR-COOLED CONDENSER

Air-cooled condensers ("ACCs") are used routinely on California and Nevada combined cycle power plants. Operational air-cooled California combined cycle plants include the 540-MW Sutter Power Plant Project, the 510-MW Otay Mesa Power Plant, and the 530-MW Gateway Generating Station. The Project's combined-cycle power block will have a gross output of 405 MW. (AFC, p. 2-26.) The AFC estimates a reduced power output of 20 to 40 MW if air cooling were used for the Project. (URS Supplemental Responses to Sierra Club Data Requests: Nos. 1 to 97, Oct. 2012, p. 68-2.) This translates into a 5 to 10 percent reduction in gross power output. The Applicant also estimates a capital cost differential, between a wet cooling tower and an air-cooled condenser at the combined cycle plant, of $20 to 30 million and a total cost differential of $50 million citing to two CEC reports. (URS Supplemental Responses to Sierra Club Data Requests: Nos. 1 to 97, Oct. 2012, p. 68-2.)

DATA REQUEST

128. Please provide the site-specific calculations and documentation that support:

a. the projected air-cooled condenser energy penalty of 5 to 10 percent;

b. the capital cost differential of $20 to 30 million;

c. and the total cost differential of $50 million.

RESPONSE

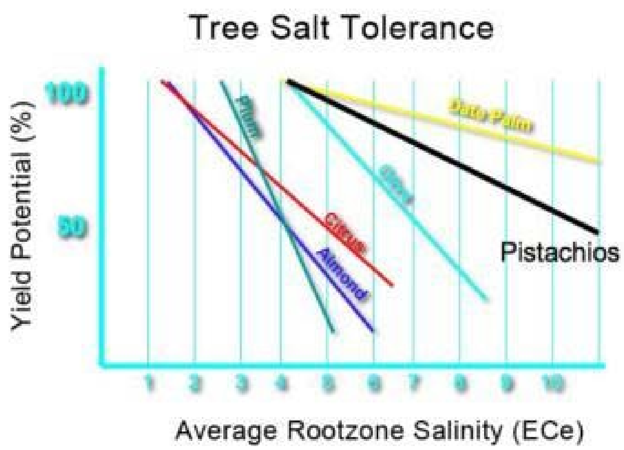
Please see Applicant's response to Data Request 127. In addition, the information that was previously provided by the Applicant indicates the reduced power output and capital cost impact is available and can be found in two studies located on the CEC website as indicated below. These studies calculate costs and impacts that are site specific and applicable just for the power generation portion of the facility.

1. Cost and value of water use at combined-cycle power plants, April 2006
CEC-500-2006-034

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

BACKGROUND: USE OF BRACKISH WATER FROM BUENA VISTA STORAGE WATER DISTRICT FOR IRRIGATION OF HIGH VALUE CROPS INSTEAD OF PROJECT COOLING

The AFC identifies the average total dissolved solids ("TDS") concentration of the brackish groundwater that would be pumped to the Project as 2,000 ppm. (AFC, p. 5.14-19.) This is equivalent to an electrical conductivity ("EC") of 3. (*See Final Environmental Impact Report for the Buena Vista Water Storage Dis*trict, Buena Vista Water Management Program , p. II-10, hereinafter BVWSD FEIR; available at https://www.box.com/s/qqtpc9ko8f57difis3zk). Several crops can be grown successfully using brackish water of this EC and TDS content. For example, the University of California at Davis has demonstrated that pistachios, a high value crop, can be grown with brackish irrigation water with an average EC of 4 (~3,000 ppm TDS) with no loss of yield, as shown in the figure below. (See http://ucanr.edu/sites/psalinity/rootstock/). Ten percent of Buena Vista Water Storage District ("BVWSD") land is in currently planted in high value pistachios. (*See* BVWSD FEIR*,* p. II-8).



DATA REQUEST

129. Please explain why the BVWSD groundwater that the Project proposes to utilize could not instead be successfully applied as irrigation water on high-value pistachios or other high value salt-tolerant crops like pomegranates.

RESPONSE

The Buena Vista Water Storage District (BVWSD) considers HECA's use of its brackish water as a beneficial part of BVWSD's Brackish Groundwater Remediation Project (BGRP). As such, BVWSD has encouraged the Project to use the brackish water. An October 29, 2012 Letter from the BVWSD states that "providing HECA with this brackish groundwater, Buena Vista will be able to implement a significant portion of the BGRP and improve water quality of the underlying groundwater for the benefit of the farmers." Furthermore, BVWSD states that the "vast region of brackish groundwater that impacts the western portions of the District is extensive and well beyond the capacity of the BGRP and therefore beyond the HECA requirements." Thus, HECA's use of a relatively small portion of the brackish water does not inhibit other uses of BVWSD's vast supplies of brackish water.

BACKGROUND: POTENTIAL CONTAMINATION OF QUALITY GROUNDWATER

Groundwater in the BVWSD is primarily seepage loss from the BVWSD irrigation ditch and canal system and infiltration from over-irrigation. (AFC Appendix N, pdf p. 53). The relatively high salinity in the area where the five wells for brackish water withdrawal for the Project would be located is apparently a localized high salinity hot spot associated with saline rock strata of limited extent. (*See* BVWSD FEIR, pdf pp. 175-176). Operation of groundwater pumps in this area may in fact draw surrounding lower TDS groundwater through the saline strata and "create" brackish groundwater which would not exist but for the action of pumping.

The BVWSD FEIR for the Brackish Groundwater Remediation Project ("BGRP") lists several other alternatives (BVWSD FEIR, pp. IV-1 to IV-8). One alternative analyzed is the On-Farm Water Use Efficiency Program. One stated purpose of this alternative is to "ease the transition into higher value crops." According to the BVWSD FEIR, this alternative "has few environmental impacts, is more complicated to implement, and is possibly more costly" than the BGRP. Use of drip irrigation to eliminate overwatering and the attendant formation of brackish shallow groundwater would eliminate the shallow brackish perched groundwater problem that BVWSD is proposing to solve by pumping 7,500 acre-feet per year ("AFY") of brackish groundwater to HECA, primarily for evaporation in cooling towers.

The negative salinity contribution of the localized groundwater TDS hotspot (BVWSD FEIR, pdf p. 175) where the five groundwater pumps will be located may be largely eliminated with the widespread adoption of the high efficiency irrigation alternative to the BGRP. The pumps would then potentially be drawing low TDS water from surrounding connected aquifers through the localized saline strata that would otherwise be largely isolated. This could mean that the pumping to supply HECA would be creating brackish groundwater that would not exist but for the pumps drawing surrounding lower TDS groundwater though the saline strata.

DATA REQUEST

130. Please provide salinity isopleths for all groundwater within five miles of the BVWSD district boundary.

RESPONSE

Figure 5.14-10 in the Amended AFC presents salinity isopleths (as represented by TDS). The isopleths shown are limited to BVWSD's service area for the following reasons:

- BVWSD only has data for wells within its service area.

- Groundwater chemistry data west of the BVWSD service area were not available, but that part of the Belridge Water Storage District is not under active agricultural production and, because of poor groundwater chemistry, continues to be unusable for agriculture. Despite the lack of TDS data west of BVWSD, it is widely accepted that groundwater west of BVWSD is of poor chemistry due to high TDS concentrations. A report published by the California Department of Water Resources (DWR), "Report on Proposed Bellridge Water Storage District" (DWR, 1961) notes that TDS from the five wells within the Belridge Water Storage District range in concentration from 2,848 milligrams per liter (mg/L) to 13,800 mg/L. An October 2010 discussion with the Kern County Water Agency (KCWA) indicated that the KCWA lacks data for the area west of BVWSD, because TDS is so high and groundwater is not used for either agricultural or domestic purposes.

- BVWSD's Buttonwillow Service Area location is within the Buttonwillow subbasin (KCWA, 1991), which may be partially isolated from adjacent hydrogeological subbasins by structural highs due to folding or faulting (see Figure 5.14-3 in the Amended AFC).

References:

California Department of Water Resources (DWR), 1961, Report on Proposed Bellridge Water Storage District.

KCWA (Kern County Water Agency), 1991. Study of the Regional Geologic Structure Related to Groundwater Aquifers in the Southern San Joaquin Valley Groundwater Basin, Kern County, California. September 20.

DATA REQUEST

131. Provide any evidence that the On-Farm Water Use Efficiency Program alternative to the BGRP would be more complicated to implement or more costly.

RESPONSE

The Applicant does not have any additional information about BVWSD's On-Farm Water Efficiency Program alternative other than what is already presented in BVWSD's Final Environmental Impact Report (FEIR).

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

Docket No. 08-AFC-08A
(Revised 11/20/12)

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DECLARATION OF SERVICE

I, Dale Shileikis, declare that on November 30, 2012, I served and filed a copy of the attached Responses to Sierra Club Data Requests – Nos. 98 through 131, dated November, 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;

___ 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 marked **"hard copy required"** or where no e-mail address is provided.

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[1] 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.

Dale Shileikis

[1] This Proof of Service form is not appropriate for the use when filing a document with the Chief Counsel under Title 20, sections 1231 (Complaint and Request for Investigation) or 2506 (Petition for Inspection or Copying of Confidential Records). The Public Advisor can answer any questions related to filing under these sections.