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California Energy Commission
DOCKETED
08-AFC-8A
TN # 68264
OCT. 30 2012

October 30, 2012

Hydrogen Energy California, LLC
Marisa Mascaro
Senior Environmental Project Manager
SCS Energy LLC
30 Monument Square, Suite 235
Concord, MA 01742
Email: mmascaro@scsenergyllc.com
CC: Docket 08-AFC-8A
BC: POS Service List

Re: HYDROGEN ENERGY CALIFORNIA PROJECT (08-AFC-8A), Sierra Club's Data Requests Set No. 2

Dear Ms. Mascaro:

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

These data requests are numbered 98 through 131. Written responses to the enclosed data requests are due to the Sierra Club on or before November 30, 2012.

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

Sincerely,

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

Sierra Club
HECA
Data Requests Set No. 2 (Nos. 98 – 131)

October 30, 2012

AIR QUALITY

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 Requests:

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.

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.

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]

Data Request:

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

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 PM2.5 and PM10 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 PM10/PM2.5 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 PM10 emissions and less than 80% of its PM2.5 emissions are emitted from combustion sources; the remaining PM10/PM2.5 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, PM10, and PM2.5 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

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

for different pollutants and averaging times raises questions about the validity of the modeling results.

Data Requests:

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.

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

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.

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.

Data Requests:

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.

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.

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

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]

Data Requests:

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.

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 Requests:

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.

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

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.

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 CH_4, *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 CH_4), 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.

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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.

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.

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 H_2S, 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.

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 Requests:

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.

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.

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 Requests:

113. Please revise the Project's PTE to include on-site PM10 and PM2.5 emissions from fugitive entrained road dust.

114. Please revise ambient air quality modeling for compliance with PM10 and PM2.5 CAAQS and NAAQS to account for on-site PM10 and PM2.5 emissions from fugitive entrained road dust.

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 Requests:

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.?

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).

Data Requests:

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

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.

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.

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.

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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 Requests:

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

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.

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.

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

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 Requests:

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.

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

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.

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.

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			

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 Requests:

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

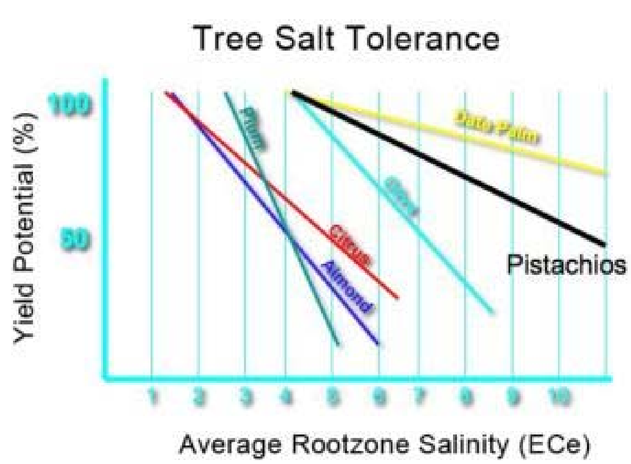
    a. the projected air-cooled condenser energy penalty of 5 to 10 percent;

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

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

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 District, 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 Requests:

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.

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 Requests:

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

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.

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

AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
(Revised 10/9/12)

APPLICANT
SCS Energy LLC
Marisa Mascaro
30 Monument Square, Suite 235
Concord, MA 01742
mmascaro@scsenergyllc.com

Tiffany Rau
2629 Manhattan Avenue, PMB# 187
Hermosa Beach, CA 90254
trau@heca.com

George Landman
Director of Finance and
Regulatory Affairs
Hydrogen Energy California, LLC
500 Sansome Street, Suite 750
San Francisco, CA 94111
glandman@heca.com

APPLICANT'S CONSULTANT
Dale Shileikis, Vice President
Energy Services Manager
Major Environmental Programs
URS Corporation
One Montgomery Street, Suite 900
San Francisco, CA 94104-4538
dale_shileikis@urscorp.com

COUNSEL FOR APPLICANT
Michael J. Carroll
Latham & Watkins, LLP
650 Town Center Drive, 20th Fl.
Costa Mesa, CA 92626-1925
michael.carroll@lw.com

INTERESTED AGENCIES
California ISO
e-recipient@caiso.com

Marni Weber
Department of Conservation
Office of Governmental and
Environmental Relations
(Department of Oil, Gas &
Geothermal Resources)
801 K Street MS 2402
Sacramento, CA 95814-3530
marni.weber@conservation.ca.gov

INTERVENORS
California Unions for Reliable Energy
Thomas A. Enslow
Marc D. Joseph
Adams Broadwell Joseph & Cardozo
520 Capitol Mall, Suite 350
Sacramento, CA 95814
tenslow@adamsbroadwell.com

Tom Frantz
Association of Irritated Residents
30100 Orange Street
Shafter, CA 93263
tfrantz@bak.rr.com

Kern-Kaweah Chapter
Of the Sierra Club
Andrea Issod
Matthew Vespa
85 Second St, Second Floor
San Francisco, CA 94105
andrea.issod@sierraclub.org
matt.vespa@sierraclub.org

INTERVENORS (con't.)
Environmental Defense Fund (EDF)
Timothy O'Connor, Esq.
123 Mission Street, 28th Floor
San Francisco, CA 94105
toconnor@edf.org

Natural Resources Defense Council
George Peridas
111 Sutter Street, 20th Fl.
San Francisco, CA 94104
gperidas@nrdc.org

Kern County Farm Bureau, Inc.
Benjamin McFarland
801 South Mt. Vernon Avenue
Bakersfield, CA 93307
bmcfarland@kerncfb.com

*indicates change

ENERGY COMMISSION – DECISIONMAKERS

KAREN DOUGLAS
Commissioner and Presiding Member
karen.douglas@energy.ca.gov

ANDREW McALLISTER
Commissioner and Associate Member
andrew.mcallister@energy.ca.gov

Raoul Renaud Hearing
Adviser
raoul.renaud@energy.ca.gov

Eileen Allen Commissioners' Technical Advisor for Facility Siting
eileen.allen@energy.ca.gov

Galen Lemei
Advisor to Presiding Member
galen.lemei@energy.ca.gov

Jennifer Nelson
Advisor to Presiding Member
jennifer.nelson@energy.ca.gov

David Hungerford
Advisor to Associate Member
david.hungerford@energy.ca.gov

*Pat Saxton
Advisor to Associate Member
patrick.saxton@energy.ca.gov

ENERGY COMMISSION – STAFF

Robert Worl Project
Manager
robert.worl@energy.ca.gov

John Heiser
Associate Project Manager
john.heiser@energy.ca.gov

Lisa DeCarlo Staff Counsel
lisa.decarlo@energy.ca.gov

ENERGY COMMISSION – PUBLIC ADVISER

Jennifer Jennings Public
Adviser's Office
publicadviser@energy.ca.gov

DECLARATION OF SERVICE

I, David Abell, declare that on October 30, 2012, I served and filed a copy of the attached **Sierra Club HECA Data Requests Set No. 2 (Nos. 98 -131)**, dated October 30, 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:
(C*heck 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 at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

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

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

/s/ David Abell

David Abell
Sierra Club, Environmental Law Program