UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105

October 21, 2010

Rod Jones
Project Manager
Systems Assessment & Facility Siting Division
California Energy Commission (CEC)
1516 Ninth Street, MS-15
Sacramento, CA 95814

Subject: Preliminary Staff Assessment (PSA) Part 1, Hydrogen Energy California (HECA) Project, Kern County, California

Dear Mr. Jones:

The U.S. Environmental Protection Agency (EPA) has reviewed Part 1 of the Preliminary Staff Assessment (PSA) for the Hydrogen Energy California (HECA) project. We understand that the Department of Energy will utilize many of the analyses contained in this PSA for the project's Environmental Impact Statement (EIS) that will be prepared later pursuant to the National Environmental Policy Act (NEPA). Please note that our provision of comments on the PSA does not preclude additional comments on the EIS, for which we have a review and commenting responsibility pursuant to the Council on Environmental Quality (CEQ) regulations (40 CFR Parts 1500-1508), and our NEPA review authority under Section 309 of the Clean Air Act. Our detailed comments follow:

Elk Hills Alternative Plans

1. What are the alternatives for the proposed plant if (1) the arrangements as described (Enhanced Oil Recovery "EOR") with the Elk Hills Field do not materialize or (2) the EOR operations terminate during the plant's operational life at a later date? In short, is HECA prepared to conduct Carbon Dioxide (CO_2) Sequestration operations under their ownership/operation (apply for Underground Injection Control (UIC) permit, etc.) under all circumstances, to assure that the proposals being represented and addressed in the Preliminary Staff Assessment are implemented?

2. The proposed plant's predicted efficiency is based upon an assumption that a 3rd party will perform the CO_2 sequestration/handling activities. Please describe alternatives that HECA has prepared to assure that the described efficiencies, etc. will be realized, should the present plans (with Elk Hills) not materialize, or break down at a later stage during operation.

Geological and Seismic Impacts

The PSA concludes that any increased seismic activity resulting from proposed CO_2 injection is not expected to exceed a magnitude 4 earthquake, citing to the report entitled

Potential for Induced Seismicity from CO2 Injection Operations at Elk Hills by Terralog Technologies, August 20, 2008. EPA would like to obtain a copy of this report. Please direct your response to George Robin at (415) 972-3532, robin.george@epa.gov, or at the above address, mailcode WTR-9.

Impacts to Air Quality

EPA provided comments to the San Joaquin Valley Air Pollution Control District (SJVAPCD) on the Preliminary Determination of Compliance for the project (letter dated August 16, 2010). Our comments are attached. Adequate response to the various analysis issues we raised in our comments is needed to ensure that impacts to air quality are less than significant, as stated in the PSA Part 1.

Public Health

EPA's comments to the SJVAPCD included a reference to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ). Although the CEC referenced Subpart ZZZZ in the air quality laws, ordinances, regulations and standards (LORS), Table 1 (page 4.1-3), because Subpart ZZZZ presents requirements for hazardous air pollutants, which are air toxics, we suggest that Supbart ZZZZ be included in the Public Health LORS, Table 1 (page 4.7-2).

Environmental Justice

Ensuring air quality impacts are less than significant also bears on the conclusion regarding less than significant air quality impacts to environmental justice (EJ) populations (p. 4.1-44)[1]. In addition, the PSA states that the outreach and involvement provision of Executive Order 12898 regarding EJ, while not binding on the CEC, was found helpful and was followed in the EJ analysis. We did not find any information on the outreach efforts that were made to the minority population near the project site. If such efforts were made, including the provision of language-appropriate outreach materials, these efforts should be summarized in the PSA.

The EJ demographics analysis and impact assessment does not include the coal import site at Wasco, California that will serve the facility. According to a testimony report before the California Public Utilities Commission[2], coal will be transported to the project site from a coal storage plant in Wasco that is in proximity to a farm labor camp. We recommend that the Wasco community be included in the EJ analysis and that appropriate outreach also occur to this community. It may be helpful to know that EPA considers the EJ analysis for the China Shipping Container Terminal Project EIR is be especially effective and recommends it use as a model for EJ analyses for other projects. That analysis is available at: http://www.portoflosangeles.org/EIR/ChinaShipping/DEIR/5_Environmental_Justice.pdf.

[1] Over half of the population within 6 miles of the project site consist of minority populations. (p. 1-4)

[2] *Testimony in Support of Application for Authorization to Recover Costs Necessary to Co-Fund a Feasibility Study of a California IGCC with Carbon Capture and Storage*, Southern California Edison, April 3, 2009

EPA appreciates the opportunity to review Part 1 of the PSA. We expect to provide additional comments on Part 2 of the PSA once it becomes available. If you have any questions, please contact me at (415) 972-3521 or contact Karen Vitulano of my staff at (415) 947-4178. For questions on the air quality comments/attachment, please contact Shirley F. Rivera of our Air Division at (415) 972-3966. We look forward to continuing to work with the California Energy Commission on this project.

Sincerely,

Kathleen M. Goforth

Kathleen M. Goforth, Manager
Environmental Review Office (CED-2)

Enclosure: EPA's Comments to the San Joaquin Valley Air Pollution Control District, August 16, 2010, on Project Number S-1093741, Hydrogen Energy California LLC (08-AFC-8)

cc: Paul Detwiler, Department of Energy
John Rockey, Department of Energy
David Warner, San Joaquin Valley Air Pollution Control District
Elena Miller, California Division of Oil, Gas, and Geothermal Resources
California Public Utilities Commission
Tim Kuhn, U.S. Fish and Wildlife Service

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

August 16, 2010

David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308

Re: EPA Comments on Project Number S-1093741
Facility Name: Hydrogen Energy California LLC (08-AFC-8)

Dear Mr. Warner:

Thank you for the opportunity to comment on San Joaquin Valley Air Pollution Control District's (SJVAPCD's) Preliminary Determination of Compliance (PDOC) for Project Number S-1093741 at Hydrogen Energy California LLC (08-AFC-8). In addition to being subject to the SJVAPCD's nonattainment New Source Review (NSR) permit project, EPA Region 9 is currently processing the federal Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) permit application for this project.

We understand that the project is a proposed integrated gasification combined cycle (IGCC) power generation facility. When firing hydrogen-rich synthesis gas derived from coal and petroleum coke blends (or pet coke), a range of approximately 248 to 251 MW (net) will be generated; when firing exclusively on natural gas, a total of up to 333 MW (net) will be generated. The PDOC states that from the IGCC operations, an exhaust stream that comprises primarily CO_2 will be transported by pipeline to a nearby oilfield for enhanced oil recovery (EOR) and sequestration.

Our comments provided in the enclosure are made in reference to the PDOC submitted to us on June 22, 2010. They include general observations, and comments addressing the engineering evaluation as well as the proposed permit conditions primarily as they pertain to the federal NSR program. Most notably, our comments include, but are not limited to federal applicable requirements based on annual emission estimates, emission calculation assumptions, and compliance demonstration requirements.

Also, consistent with the requirements of Title VI of the Civil Rights Act of 1964, EPA recommends that the District take reasonable steps to ensure that individuals who may have limited ability to read, write, speak or understand English ("limited English proficiency " or "LEP") have meaningful access to its permitting process. (See "Guidance to Environmental Protection Agency Financial Assistance Recipients Regarding Title VI Prohibition Against National Origin Discrimination Affecting Limited English Proficient Persons," 69 Fed. Reg. 35602 (June 25, 2004).)

We look forward to working with you to address our comments prior to the issuance of the Final Determination of Compliance (FDOC). Please contact me or Shirley F. Rivera of my staff at (415) 972-3966 if you have any questions.

Sincerely,

Gerardo C. Rios
Chief, Permits Office

Enclosure

cc: Homero Ramirez, San Joaquin Valley Air Pollution Control District
Michael Tollstrup, California Air Resources Board
Rod Jones, California Energy Commission
Gregory Skannal, Hydrogen Energy California LLC
Julie Mitchell, URS Corporation
Paul Detwiler, U.S. Department of Energy

EPA Comments on the Preliminary Determination of Compliance (PDOC) for Hydrogen Energy California, Project No. S-1093741 (08-AFC-8)

1. **Annual Emissions Estimates** – Applicable federal requirements include thresholds for defining a major source of criteria pollutant or of hazardous air pollutant (HAP) emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

   We have identified estimated emissions of certain pollutants that are within a margin of less than 5% of the federal annual threshold limits. These limits include the nonattainment New Source Review (NSR) threshold of 100 tons per year (tpy) for PM2.5 and the major source of Hazardous Air Pollutant (HAP) thresholds of 10 tpy for a single HAP and 25 tpy for cumulative HAP emissions. If the limits of these pollutants are relaxed, the facility would be subject to the applicable federal requirements; for PM2.5, nonattainment New Source Review would be required, and for HAP emissions, evaluation for case-by-case Maximum Available Control Technology (MACT) would be required. Each is further discussed below.

2. **PM2.5 Federal Nonattainment New Source Review (NSR) Applicability** – The San Joaquin Valley APCD presents the major source determination for all criteria pollutants on page 62 (Section VII.C.1.) of the engineering evaluation. PM2.5 is estimated at 198,650 pounds per year, or an equivalent of approximately 99.3 tons per year (tpy). As stated by the District in its evaluation, on May 8, 2008 EPA finalized regulations to implement the NSR program for PM2.5. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a non-attainment area is defined as a major stationary source.

   The equipment primarily contributing to PM2.5 emissions includes the combined cycle combustion turbine generator (CTG) and the cooling towers; other equipment emitting PM2.5 includes the feedstock handling and combustion-related sources. The District has assumed that all PM10 estimated emissions from the CTG are PM2.5 emissions. The District has assumed that 60% of the PM10 estimated emissions from the cooling towers are PM2.5. If it is determined that the estimated emissions are not representative of the potential-to-emit (PTE) and equal or exceed 100 tpy, the following would also be required: the lowest achievable emission rate control technology and offsetting of PM2.5 emissions with creditable emission reductions.

   Please note that in the event that PM2.5 offsets are required and the project proponent were to consider using SO2 reductions to offset the project's PM2.5 emissions, paragraph IV.G.5 of Part 51, Appendix S currently provides that offset requirements for direct PM2.5 emissions under Appendix S may be satisfied by offsetting reductions of emissions of SO2 only "if such offsets comply with an interprecursor trading hierarchy and ratio approved by the Administrator." Morevover, although the provisions concerning trading ratios for interpollutant trading for PM2.5 emissions and other aspects of EPA's PM2.5 NSR Implementation Rule (73 FR 28321 (May 16, 2008)) are currently subject to reconsideration by the Agency (see 74 FR 26098 (June 1, 2009)), the modeling conducted by EPA in the context of development of those ratios supports a significantly higher PM2.5 to SO2 ratio than the 1:1 ratio used by the District for PM10 to SO2 interpollutant trading.

3. **Annual Estimates of PM2.5 Emissions and Compliance Demonstration** – As noted above, PM2.5 is estimated at 198,650 pounds per year, or an equivalent of approximately 99.3 tons per year (tpy) for the facility operations. (See Page 61, Table titled "Major Source Determination"; see also Appendix F) The equipment primarily contributing to the PM2.5 emissions estimate include the combined cycle combustion turbine generator (CTG) and the cooling towers. The PDOC indicates that these two sources together contribute an estimated 106.4 tpy of PM10 emissions and 96.8 tpy of PM2.5 emissions. The following highlights our comments regarding CTG and cooling tower PM2.5 emission estimates and the respective compliance demonstration methods.

   - <u>Combustion Turbine Generator (S-7616-9-0)</u> – It is assumed that the PM2.5 emissions from the CTG are equal to the PM10 emissions of 19.8 lbs/hr. EPA supports this assumption. Compliance demonstration for the source testing of PM10 emissions is proposed in Condition 47.

     However, it is unclear why these estimated emissions are approximately twice what EPA has permitted and/or reviewed for similar CTGs. Given what appears to be additional conservatism in the hourly emissions, EPA requests further discussion in the engineering evaluation regarding the rationale supporting the higher value, as well as consideration of a further reduction of PM10 emission limits based on source test results. For example, has the District considered further reducing the PM10 emission limits presuming source tests demonstrate lower emissions, similar to the approach for NOx, CO and VOC emissions as proposed in Conditions 81-85.

   - <u>Cooling Towers Emissions (S-7616-4-0, S-7616-11-0, S-7616-12-0)</u> – For all three cooling tower operations, the applicant estimates estimated that the PM2.5 emissions from the cooling towers are 60% of the PM10 emissions. (Additionally, the applicant estimates assumed that all PM emissions are PM10 emissions.) Compliance demonstration for PM10 emissions from this equipment is based on a calculation methodology. This methodology includes a 0.0005% drift rate (representing BACT) from the cooling tower drift eliminator, a total dissolved solids (TDS) concentration not to exceed 9,000 ppm, annual operations limited to 8,322 hours per year, and cooling water circulation rates specific to each operation. (See pages 43-44 of PDOC engineering evaluation.)

     The applicant has assumed that the 60% PM2.5 size fraction is likely based on the California Air Resources Board (CARB) database information in its California Emission Inventory Development and Reporting System (CEIDARS). This assumption is based on the applicant's use of information from the South Coast Air Quality Management District

(SCAQMD). It is our understanding that the SCAQMD has assumed a 60% size fraction, which is based on a CEIDARS value; however, this CEIDARS value is not specific for cooling towers. Therefore, EPA requests further justification of the size fraction of PM2.5 emissions from the cooling towers and/or additional compliance demonstration requirements. Otherwise, it should be assumed that PM2.5 emissions from the cooling towers are equal to the estimated PM10 emissions.

With respect to the District's proposed compliance demonstration, it appears that the compliance demonstration options that EPA is considering may differ from the District's proposed requirements. We acknowledge that the District is requiring quarterly sampling of the blowdown water to estimate TDS. EPA understands that site-specific data is necessary to determine the correlation between TDS and particulate matter emissions (*i.e.*, PM, PM10, PM2.5). PM, PM10, and PM2.5 can vary significantly with plant operations and maintenance. Therefore, in order to use a calculation method, as proposed by the District, site-specific data and testing is necessary to demonstrate compliance with the proposed emission limits. EPA is available to discuss this in more detail for the District's consideration.

4. **Annual Estimates of HAP Emissions and Compliance Demonstration** – Hazardous air pollutant (HAP) emissions are discussed on pages 94-95 of the PDOC engineering evaluation and presented in Appendix I of the PDOC. To remain below the major source MACT threshold, a single HAP must be less than 10 tpy, and the combined HAPs must be less than 25 tpy. Although the HAP emissions section of the PDOC discusses the conduct of testing for speciated HAPs and total VOC source testing for the CTG, the process primarily contributing to the limit of not more than 10 tpy of a single HAP is the intermittent CO2 vent system, which is part of the CO2 recovery and vent system (S-7616-8-0). Operating scenarios for venting are described in the PDOC, pages 30-31.

   Carbonyl sulfide emissions (COS) are estimated at 9.9 tpy. This estimate is based on imposing operating limits and therefore appears to be a synthetic area source. As a result, the District must require practically and federally enforceable potential-to-emit limits to assure this process is not emitting at the major source level of 10 tpy.

   In order to remain below the 10 tpy threshold, the District has proposed permit conditions based on assumptions presented in the calculation methodology provided by the applicant. COS annual emission estimates are based on a maximum CO2 vent stream flow rate of 656,000 lbs/hr; proposed Condition 6 limits the vent stream flow rate. Furthermore, Condition 10 requires a gas flowmeter for the vent system flow rate, and Condition 11 requires recordkeeping of venting events. EPA understands this flow rate is estimated to be the same for both early and mature operating scenarios.

   COS annual emission estimates are also based on operations of the CO2 recovery and vent system of not more than 504 hours per year (or an estimated 21 days per year); proposed Condition 7 limits the annual hours on a rolling 12-month period. Unlike the maximum vent stream flowrate, EPA understands that CO2 venting is expected to be less than one-half (e.g., 5-10 days) during mature operations compared to the early operating scenario.

Because the annual tons per year of HAPs is dependent on the hours of venting, including a method for tracking those hours is critical. The flowmeter or another piece of equipment should track the hours of venting. In addition, it is unclear whether the partial hours of venting, e.g., 30-minutes, 45-minutes, are accounted. Therefore, please provide permit conditions and/our require additional monitoring equipment with associated recordkeeping requirements that will assure an accurate accounting of the total hours of operation.

Also, EPA suggests that the District include a condition that includes a lower number of allowable annual hours upon achieving mature operations to provide additional assurance that HAP emissions will not exceed 9.9 tpy. Additionally, as outlined on pages 30-31, allowable CO_2 venting events (associated with Condition 11) and associated recordkeeping should be included as permit conditions.

5. **Federal Requirements for Internal Combustion Engines** – Please include a discussion of the applicability of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (40 CFR Part 63, Subpart ZZZZ) and of the Standards of Performance for New Stationary Sources (NSPS) for Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII) as they may apply to the diesel fuel-fired emergency generator sets (S-7616-14-0, S-7616-15-0) and firewater pump engine (S-7616-16-0). Based on the applicability determination, EPA suggests that the District incorporate federally enforceable permit conditions to assure compliance with these requirements, as needed.

6. **Consistency of PDOC Information with PSD Information** – For the purposes of EPA's review of the PDOC evaluation and PDOC, although not required as part of our PSD permit application review and preparation of proposed permit conditions, we are in the process of identifying whether information provided by the Applicant through the PSD permit application process is consistent with the information in the District's evaluation. We would like to ensure that, at a minimum, those data sets and assumptions shared between the PSD and PDOC processes that contribute to the determination of the potential-to-emit, BACT, and assumptions for the air quality analysis/modeling are consistent. At this time, we simply would like to make the District aware that this evaluation is in process. To the extent that we identify inconsistencies during our review, we will address them as part of our PSD permit process.

7. **Equivalent Equipment, Internal Combustion Engines and Auxiliary Boiler** – The District has included conditions for these equipment (S-7616-13-0, S-7616-14-0, S-7616-15-0, S-7616-16-0) that allows for the use of equivalent equipment upon written District approval. As stated in the proposed permit conditions, approval is granted upon "... *determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment.*" EPA suggests that the District also evaluate the air quality modeled impacts of any proposed equivalent equipment.

8. **Operating Work Practices and Annual Hours of Operations** - EPA requests the following conditions be added for the equipment listed below:

- Cooling Towers (S-7616-4-0, S-7616-11-0, S-7616-12-0) – For each equipment, please include an operating limit of 8,322 hours per year, along with any necessary recordkeeping requirements.
- Sulfur Recovery System (S-7616-5-0) – Condition 13 required the incinerator firebox temperature to be maintained above 1,200 deg F. Please include a condition that allows compliance demonstration with the temperature.
- Flares (S-7616-3-0, S-7616-6-0, S-7616-7-0) – Condition 10 of the Rectisol AGR emergency flare (S-7616-7-0) allows operations for emergency situations. The PDOC references that the flare will be limited to 200 hours per year of non-emergency operations. Please include a description of the allowable emergency situations, as well as reference to the non-emergency operations.
- Auxiliary Boiler (S-7616-13-0) – For each equipment, please include an operating limit of 2,190 hours per year, along with any necessary recordkeeping requirements. There is reference to flue gas recirculation in Condition 19. Please propose a permit condition that requires the operator to properly operate and maintain the FGR system, which is part of NOx control for the boiler.
- CO2 Recovery and Vent System (S-7616-8-0) – As previously commented under the annual estimates of HAP emissions, allowable CO2 venting events (associated with Condition 11) and associated recordkeeping should be included as permit conditions. Furthermore, specifics about the monitoring requirements for CO, VOC and H2S in Condition 12 should be detailed. Under Condition 8, please clarify the reference for the ppm concentration limits.