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By email

May 30, 2013

Robert Worl, Project Manager
California Energy Commission

Re: Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903

Dear Mr. Worl:

Please accept these comments submitted on behalf of the Sierra Club regarding the Preliminary Determination of Compliance ("PDOC"), noticed on February 7, 2013 by the San Joaquin Valley Air Pollution Control District for Hydrogen Energy California, LLC, Facility # S-7616, Project # S-1121903. These comments were prepared with the technical assistance of Petra Pless, D. Env., Bill Powers, MS, P.E., and Camille Sears, MS.

Sincerely,

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May 30, 2013

By email

Mr. David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
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Bakersfield, CA 93308
Email: David.Warner@valleyair.org
cc: Homero.Ramirez@valleyair.org

Re: Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903

Dear Mr. Warner,

Please accept these comments submitted on behalf of Sierra Club[1] regarding the Preliminary Determination of Compliance ("PDOC"), noticed on February 7, 2013 by the San Joaquin Valley Air Pollution Control District ("District" or "SJVAPCD") for Hydrogen Energy California, LLC ("HECA" or "Applicant"), Facility # S-7616, Project # S-1121903 ("Project" or HECA Project").[2]

The Sierra Club is the oldest and largest grassroots environmental group, with over 1.3 million members and supporters. Sierra Club members live, work, attend school, travel and recreate in areas adversely affected by power plant emissions. Our members enjoy and are entitled to the benefits of natural resources that are adversely affected by interstate pollution, including air, water and soil; forests and cropland; parks, wilderness areas and other greenspace; and flora and fauna. The activities enjoyed by our membership that would be affected by the proposed HECA Project include breathing, enjoyment of scenic views, walking, gardening, hiking and work-related activities. Our membership and their families include members of sensitive

[1] These comments were prepared with the technical assistance of Petra Pless, D. Env., Bill Powers, MS, P.E., and Camille Sears, MS.

[2] SJVAPCD, Notice of Preliminary Determination of Compliance, Facility# S-7616, Project # S-1121903, February 14, 2013; http://www.valleyair.org/notices/public_notices_idx.htm.

populations such as asthmatics, the elderly and children who are at elevated risk for the deleterious health effects posed by power plant emissions.

Sierra Club understands that the California Energy Commission ("CEC") has the authority to approve the HECA Project through its Application for Certification ("AFC") process,[3] the District's PDOC is functionally equivalent to an Authority to Construct ("ATC") review, and the PDOC is intended to provide comments and guidance to the CEC on the proposed Project's compliance with air quality requirements.

Sierra Club appreciates the District's extensive efforts in drafting the PDOC for this complex project; however, Sierra Club finds that the document fails to demonstrate the Project's compliance with the requirements of the federal Clean Air Act ("CAA" or "the Act") and state Clean Air Act and implementing District regulations.

Among other issues detailed below, the PDOC impermissibly authorizes the use of invalid emission reduction credits (ERCs) to offset HECA's emissions of nonattainment pollutants. The HECA Project may not use banked ERCs to offset ozone precursors and particulate matter equal to or smaller than 2.5 micrometers ("PM2.5" or "fine particulate") because it does not have valid attainment plans in place to assure that allowing emission increases from HECA is consistent with "reasonable further progress" towards attainment. Even if the District were permitted to use banked ERCs to offset emissions from the HECA Project, several of the proposed ERCs are invalid and do not meet the requirements of the District's rules and the federal Clean Air Act.

The PDOC also fails to demonstrate compliance with national and state ambient air quality standards. Sierra Club has corrected modeling errors in the PDOC and has found that the 24-hour PM10 impacts from the proposed HECA Project will exceed the 24-hour PM10 PSD increment of 30 μg/m3 and the 50 μg/m3 24-hour PM10 CAAQS. The San Joaquin Valley already experiences very high PM10 levels, which are very close to putting the region back into nonattainment status for this pollutant. The PM10 impacts from the HECA Project only add to this concern and could jeopardize the current PM10 attainment status in the southern San Joaquin Valley. It is therefore essential that the 24-hour PM10 emission rates must be corrected and completely reassessed with updated modeling analyses in the PDOC.

Sierra Club also finds that the PDOC is inadequate in that it:

- Relies on numerous assumptions that are not adequately supported;
- Does not adequately analyze alternatives;

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[3] *See* CEC, Hydrogen Energy California Power Plant Project, Docket 08-AFC-8A (Amended Application for Certification); http://energy.ca.gov/sitingcases/hydrogen_energy/index.html.

- Underestimates the Project's potential to emit ("PTE") for criteria pollutants, greenhouse gases ("GHGs"), hazardous air pollutants ("HAPs") and toxic air contaminants ("TACs");
- Fails to ensure that all emission limits would be practically enforceable;
- Fails to establish best available control technology ("BACT") for cooling towers, flares, fugitive equipment leaks, and fails to establish BACT emission limits for PM2.5 and GHGs;
- Erroneously defines the HECA Project as a synthetic minor source of HAPs;
- Fails to demonstrate compliance with the new mercury and air toxics standard ("MATS");
- Fails to address the potential for nuisance and injury or damage to business or property;
- Is impenetrable, internally inconsistent, inconsistent with information provided by the Applicant, contains a number of erroneous statements and is not adequate to inform the public of the consequences of this complex facility.

Sierra Club requests that the District substantially redraft the PDOC terms and conditions to address these issues and renotice the revised PDOC to provide adequate and correct guidance to the CEC and to provide the public with a meaningful opportunity to comment.

Sierra Club endorses Greenaction's request dated May 28, 2013, to translate all the permitting materials into Spanish and to extend the comment period to allow the Spanish speaking community living nearby the proposed plant site equal opportunity to review and comment on this major new source of air pollution.

Sierra Club will gladly provide the District with a copy of any document referenced in these comments upon request. Please do not hesitate to contact me with any questions.

Respectfully Submitted,

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I. PROJECT DESCRIPTION

The HECA Project would consist of a power generation facility, an integrated fertilizer manufacturing complex, and carbon dioxide ("CO_2") capture for off-site enhanced oil recovery ("EOR") and sequestration. The facility would use integrated gasification combined cycle ("IGCC") technology to convert a fuel blend of 75 percent western sub-bituminous coal and 25 percent petroleum coke ("petcoke") into hydrogen-rich syngas, which will be used to generate electricity in a combined-cycle power block and to manufacture nitrogen-based fertilizer.[4]

The proposed facility would be located about seven miles west of the outermost edge of the City of Bakersfield and one and a half miles northwest of the unincorporated community of Tupman in western Kern County in the San Joaquin Valley portion of the Central Valley.[5] The San Joaquin Valley air basin is currently designated as nonattainment with the state and national ambient air quality standards for fine particulate matter or PM2.5; nonattainment with the state standard for particulate matter equal to or smaller than 10 micrometers ("PM10" or "respirable particulates"); nonattainment with the 3-hour state standard for ozone, severe nonattainment with the 1-hour state standard for ozone, and extreme nonattainment with the 3-hour national standard for ozone.[6]

According to the PDOC, the HECA Project would be major source of air pollutants emitting nitrogen oxides ("NOx") and volatile organic compounds ("VOCs"), which are both ozone precursors, as well as PM10 and carbon monoxide ("CO") in excess of the District's applicable major source thresholds pursuant to SJVAPCD Rule 2201.[7] In addition, the HECA Project would be a major source for nitrogen dioxide ("NO_2"), CO, and CO_2-equivalent ("CO_2e") greenhouse gas emissions for purposes of prevention of significant deterioration ("PSD") of air quality pursuant to 40 CFR 52.21 (b)(1)(i)[8] and would emit NO_2, CO, particulate matter ("PM"), PM10 and CO_2e in excess of the applicable PSD significant emission increase thresholds.[9] The HECA Project would also emit TACs, as defined under California Title 17, CCR, §93000, and HAPs, as defined by the federal Clean Air Act §112(b)(1), including acetaldehyde,

[4] PDOC, pp. 1 and 3.

[5] *Ibid.*

[6] PDOC, Appx. K, p. 7.

[7] PDOC, p. 94.

[8] PDOC, p. 96.

[9] PDOC, p. 97.

ammonia ("NH_3"), carbonyl sulfide ("COS"), hydrogen sulfide ("H_2S"), methanol ("MeOH"), propylene, sulfuric acid and sulfates, and diesel particulate matter.[10]

The Project's surrounding area is classified as PSD Class II but there are three Class I areas – parks or wilderness areas given special protection under the federal Clean Air Act – near the Project site with one area being located within 100 kilometers ("km") of the Project site: San Rafael Wilderness (60 km); Domelands Wilderness Area (105 km), and Sequoia National Park (120 km).[11]

II. THE PDOC IS NOT ADEQUATELY SUPPORTED, INTERNALLY INCONSISTENT, AND INCONSISTENT WITH INFORMATION PROVIDED BY THE APPLICANT

As discussed below, the PDOC fails to provide adequate documentation for the District's conclusions and determinations; is inconsistent with updated emission information provided by the Applicant; and provides for the potential future expansion of the HECA Project to allow for offsite transport of liquid ammonia in contradiction to assurances made by the Applicant before the CEC.

II.A Failure to Provide Supporting Documentation

The District published the PDOC as a standalone document without including for public review the Applicant's application for Authority to Construct ("ATC") and PSD permits for the HECA Project ("Application").[12] Yet many of the PDOC's determinations, *e.g.*, its BACT determinations, reference and rely upon the Application[13] and cannot be reviewed or understood without access to information contained therein. Where the PDOC incorporates assumptions from and draws conclusions based upon the Application, it must provide either a separate standalone discussion or incorporate

[10] PDOC, Appx. H.

[11] PDOC, Appendix K, p. 29.

[12] Hydrogen Energy California LLC (HECA), Authority to Construct (ATC) Permit Application and Supplemental Information for the Prevention of Significant Deterioration (PSD) Permit Application, Hydrogen Energy California (HECA) Project, May 2012.

[13] For example, PDOC, footnotes to tables on p. 45 (*See* DOC Application, p. 2 of 32 in Appendix D"); Footnote 37, p. 97 ("These emission increases are tabulated in Table 8-4 of the PSD application, which is found in Appendix F of this evaluation."); Appx. K, p. 18 ("Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application."); Appx. K, p. 28, ("… Figure 6-1 through 6-5 of the PSD application indicates…"); Appx. K, p. 41 ("… as seen in Figure 4-1 & 4-2 of the Project application…"); Appx. K, p. 42 ("Modeled source parameters are listed in the PSD Application, Appendix D. A detailed explanation of each of the modeling scenarios is included in the Section 4.1 of the PSD Application."); etc.

the Applicant's document into an appendix. These materials should be provided in both English and Spanish.[14]

Further, the PDOC does not provide all detailed calculations supporting its emission estimates, thereby preventing public review of their accuracy. For example, the PDOC, p. 93, presents a summary table for the post-project stationary source potential to emit ("SSPE2") in units of pounds per year ("lbs/yr"). The PDOC provides portions of emission calculations in the main body of the text (*e.g.,* in Section VII "General Calculations" and in Appendix F for various combustion turbine generator/heat recovery steam generator ("HRSG") and coal dryer stack emission scenarios) but does not document all necessary assumptions or show comprehensively how each emission estimate was derived:

- For example, while the PDOC, Appendix F, provides detailed spreadsheets summarizing assumptions for estimating emissions from the HRSG and coal drying stack during commissioning and startup/shutdown, it does not provide similar detailed spreadsheets for operational emissions during normal operations to support the assumptions and calculations presented in the main body of the document.

- Similarly, in Appendix H the PDOC presents a summary table for annual emissions of hazardous air pollutants ("HAPs") in units of lbs/yr for HECA's emission units including the combustion turbine generator ("CTG") stack, coal dryer stack, cooling towers, auxiliary boiler, ammonia plant startup heater, emergency generator, fire water pump, flares, tail gas thermal oxidizer, CO_2 vent, manufacturing complex, etc., but does not provide the associated emission calculations for each emission unit nor does it document how individual emission rates for each unit were derived.

- Likewise, the PDOC's ambient air quality impact and health risk assessment report ("AAQI/HRA Report") describes emission scenarios and summarizes source stack parameters[15] but does not quantify the emission rates from the respective sources that were modeled. Thus, the results of the ambient air quality modeling and the PDOC's conclusion that HECA Project emissions would not result in significant health impacts are not adequately supported.

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[14] The District claims that as part of its Environmental Justice Mission it "provides outreach materials… in multiple languages," "will work to provide easy to understand summaries of plans and reports of interest in multiple languages," and "provides, as requested, real-time interpretation services for high-profile and EJ-focused forums or meetings." SJVAPCD, Environmental Justice Strategy, Amended: June 21, 2012, pp. 10-11;
http://www.valleyair.org/programs/environmentaljustice/AmendedEJStrategy_June2012.pdf.

[15] PDOC, Appx. K, pp. 18, 42, and 56.

Sierra Club recommends that the District amend the PDOC to include detailed emission calculations, *i.e.*, a copy of all spreadsheets it relied upon, in appendices (comparable to Appendices D and F provided with the Application) and recirculate the document for public review.

Finally, the PDOC provides no vendor guarantees for the many assumptions it incorporates into its emission calculations, as discussed in more detail in Comment V.A.

II.B Inconsistencies in Emission Estimates

The emission estimates presented by the PDOC are internally inconsistent as well as inconsistent with more recent revised emission estimates provided by the Applicant to the CEC and Sierra Club on January 10, 2013 ("1/10/2013 HECA Updated Emissions Data"),[16] which were presumably also provided to the District. For example:

- The PDOC, p. 93, summarizes total **NOx** emissions from the facility at 371,310 lbs/year (*i.e.*, 185.7 tons/year) in contrast to p. 96 in the same document, which summarizes total NOx emission from the facility at 158.7 tons/year. Both amounts are inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total NOx emissions from the facility at 158.8 tons/year.

- The PDOC, pp. 93 and 96, summarizes total **PM10** emissions from the facility at 178,863 lbs/year and 89.4 tons/year. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total PM10 emissions from the facility at 90.1 tons/year, 0.7 tons/year higher than the PDOC.

- The PDOC, p. 93, summarizes total **PM2.5** emissions from the facility at 158,151 lbs/year (79.1 tons/year). This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total PM2.5 emissions from the facility at 79.9 tons/year, 0.8 tons/year higher than the PDOC.

- The PDOC, pp. 93 and 96, summarizes total **VOC** emissions from the facility at 75,379 lbs/year and 37.7 tons/year. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total VOC emissions from the facility at 38.4 tons/year, 0.7 tons/year higher than the PDOC.

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[16] Michael Carroll, Latham & Watkins, Letter to Robert Worl, CEC, Re: Hydrogen Energy California Power Plant (08-AFC-08A), January 10, 2013, CEC Docket Log ID 69092; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-01-10_Applicant_Letter_to_CEC_re_Non_Confidential_Emissions_Data_TN-69092.pdf.

- The PDOC, Appendix H, Table 5-2, summarizes total **TAC** and **HAP** emissions from the facility at 181.47 tons/year and 15.94 tons/year, respectively. This is inconsistent with the 1/10/2013 HECA Updated Emissions Data which summarize total TAC and HAP emissions from the facility at 186.44 tons/year and 19.12 tons/year. Emissions of methanol, for example, increased from 7.09 tons/year in the PDOC to 9.83 tons/year by including methanol emissions from the CO_2 vent.

These inconsistencies amount to significant differences that could have major impacts on other analyses in the PDOC. Sierra Club recommends that the District review and confirm the Applicant's revised assumptions and most recent emission estimates for the HECA Project and incorporate updates into a revised PDOC and modeling as appropriate, taking into account Sierra Club's comments below.

II.C Inappropriate Authorization for Future Installation of Liquid Ammonia Loading Facility

The PDOC states that "the plant has been designed with facilities to load liquid ammonia for sale onto railcars or into trucks for off-site shipment to allow for future operational flexibility."[17] In the proceedings before the CEC, Sierra Club raised concerns regarding risks to the surrounding population due to an accidental release of liquid (anhydrous) ammonia caused by a traffic accident involving a delivery vehicle on non-highway delivery routes and requested preparation of a risk analysis for transportation of anhydrous ammonia resulting from a delivery vehicle accident taking into account the agricultural nature of the surrounding area and the likely presence of slow-moving and oversized agricultural vehicles on the roads.[18] In response, the Applicant stated, and confirmed several times, that it "has revised the Project to eliminate the off-site transport and sale of anhydrous ammonia. Because of this change, only urea and urea ammonium nitrate for agricultural use will be transported off-site for sale. Therefore, non-highway delivery routes and a risk analysis for the transportation of anhydrous ammonia is [sic] not applicable to the Project."[19] Therefore,

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[17] PDOC, p. 17.

[18] Sierra Club Data Request No. 85, August 2, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2012-08-03_sierra_clubs_data_requests_set_01_TN-66429.pdf.

[19] HECA Response to Sierra Club Data Request No. 85, 60-Day Extension, November 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf;

Transcript of the January 16, 2013 Status Conference, p. 39; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2013-01-16_Transcript_of_Status_Conference_TN-2918.pdf; and the PDOC's reference to a potential future ammonia loading facility that would accommodate future operational flexibility should be removed and the flow diagram for the ammonia synthesis unit in Appendix E, Figure 2-29, should be revised to eliminate the loading facility. Sierra Club requests that the District honor the concerns regarding risks to the surrounding population and include a condition of compliance stipulating that a liquid ammonia loading facility may not be added to the HECA Project at any time in the future.

III. THE PDOC DOES NOT ADEQUATELY ADDRESS ALTERNATIVES

As discussed in the following, the PDOC fails entirely to provide an alternatives analysis to satisfy the requirements under Clean Air Act, Section 173(a)(5) and SJVAPCD Rule 2201, Section 4.15.1. Further, the alternatives analysis provided by the Applicant as part of its BACT analysis for the Application, upon which the PDOC relies to determine compliance with the requirements of the Clean Air Act at 40 CFR 52.21(j) for attainment pollutants and 40 CFR 51.165(a) for nonattainment pollutants as well as SJVAPCD Rules 2410 and 2201, is deficient.

III.A The PDOC Fails to Analyze Alternatives Under Clean Air Act Section 173(a)(5) and SJVAPCD Rule 2201, Section 4.15.1

New sources intending to locate in nonattainment areas such as the District must conduct an additional alternatives analysis that demonstrates the benefits of the proposal significantly outweigh the social and environmental impacts. Specifically, Clean Air Act Section 173(a)(5) requires "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source [that] demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification."[20] SJVAPCD Rule 2201, Section 4.15.1, implements this section as follows:

> For those sources for which an analysis of alternative sites, sizes, and production processes is required under Section 173 of the National Clean Air Act, the applicant shall prepare an analysis functionally equivalent to the requirements of Division 13, Section 21000 et. seq. of the Public Resources Code.

The PDOC completely ignores these clear statutory and regulatory requirements. The PDOC does not even mention alternative sites, sizes and production processes. For

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HECA Response to Sierra Club Data Request No. 135, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[20] Emphasis added.

example, the PDOC does not evaluate siting the HECA Project on the Elk Hills Oil Field instead of prime agricultural land. Nor does the PDOC analyze the environmental and social costs of locating this facility around farmland and environmental justice communities already significantly overburdened by the worst air quality in the nation. The District must issue a revised PDOC before making a final decision. The PDOC must include the District's review of an alternatives analysis, as well as its determination that the benefits of the HECA Project significantly outweigh the environmental and social costs. It is critical that the District give the public an opportunity to review and comment on its analysis of the environmental and social costs of the HECA Project.

A nonattainment alternatives analysis is a broad inquiry into "the environmental and social costs" of a project.[21] Because this is a separate and distinct requirement of the Clean Air Act, it is not limited to whether or not the Project complies with other requirements of the Act such as best available control technology (in other words the alternatives section contained in the Applicant's BACT analysis does not satisfy the requirements of Clean Air Act Section 173(a)(5) besides not having been made publicly available.). One fundamental tenet of statutory construction is that every word and clause must be given effect. The District must give effect to every word in Clean Air Act Section 173(a)(5) including the broad terms "environmental and social costs" and "significantly outweigh." To adequately evaluate "environmental and social costs," the District must analyze public health and economic impacts from locating a new major source of air pollution in the dirtiest air basin in the country, impacts on sensitive populations including the nearby Elk Hills School, impacts on environmental justice communities, as well as impacts from the rail and truck emissions.

III.A.1 The Alternatives Analysis Must Consider Public Health and Economic Impacts from Increased Air Pollution in the Dirtiest Air Basin in the Country

Kern County in California's San Joaquin Valley has the worst air quality in the nation.[22] It is designated as an extreme non-attainment area for the federal 8-hour ozone standard, a nonattainment area for the state 1-hour ozone standard, a severe nonattainment area for the state 3-hour ozone standard, a nonattainment area for PM2.5 under both federal and state standards, as well as a state nonattainment area for PM10. Jared Blumenfeld, Regional Administrator for the U.S. Environmental Protection Agency ("EPA"), acknowledged the gravity of the situation when he recently stated:

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[21] Clean Air Act Section 173(a)(5); SJVAPCD Rule 2201, Section 4.15.1.

[22] *See* American Lung Association, State of the Air 2013, pp. 16-18 (2013); http://www.stateoftheair.org/2013/assets/ala-sota-2013.pdf.

"Four times more people die in the San Joaquin Valley from air pollution than they do from traffic fatalities."[23]

Residents of Kern County regularly experience air pollution levels known to harm health and to increase the risk of early death. In Kern County, each person is on average exposed to unhealthy levels of ozone on over 50 days a year.[24] Ozone pollution can cause a range of impacts including school absences, hospitalizations, and even premature death. Exposure to fine particles is also very dangerous and can lead to a range of impacts including loss of work days, chronic bronchitis, and premature death.[25] Recent studies have found that asthma emergency room admissions are strongly linked to increasing fine particulate and ozone pollution across the region, and children face the highest risk.[26]

Residents also pay a high economic price for the region's poor air quality. A recent study found the cost of air pollution in the San Joaquin Valley overall is more than $1,600 per person per year in health care costs, which translates into a total of nearly $6 billion dollars a year.[27] These numbers do not include other economic impacts that residents must bear. For example, EPA has imposed a penalty on the San Joaquin Valley for not meeting progress goals towards attainment with the federal 1-hour ozone standard by the 2010 statutory deadline. That failure triggered a per-ton fee on ozone-related emissions from major industrial sources. The District, however, gutted this mandated incentive by adopting an ozone fee rule that exempts most industrial sources and instead passed on the fine to residents who must now pay a surcharge on their vehicle registration every year collecting a total of $29 million annually.[28] In addition, farmers face some of the most severe regulations and costs for compliance in the nation. The HECA Project would further increase levels of pollution in this already overburdened region and have direct and serious public health and economic impacts.

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[23] Alex Breitler, EPA Plan Keeps Valley Front, Center; Recordnet.com, January 25, 2012; http://www.recordnet.com/apps/pbcs.dll/article?AID=/20120125/A_NEWS/201250326&cid=sitesearch.

[24] Jane V. Hall, Victor Brajer, and Frederick W. Lurmann, The Benefits of Meeting Federal Clean Air Standards in the South Coast and San Joaquin Valley Air Basins, hereafter "Benefits of Meeting Federal Clean Air", November 2008; http://www.aqmd.gov/news1/2008/JaneHallStudy2008.pdf.

[25] *Ibid.*

[26] John Amson Capitman and Tim R. Tyner, The Impacts of Short-term Changes in Air Quality on Emergency Room and Hospital Use in California's San Joaquin Valley, June 2011, p. ii; http://www.fresnostate.edu/chhs/cvhpi/documents/aqr-web.pdf.

[27] Benefits of Meeting Federal Clean Air, p. 5.

[28] Steven Mayer, The Bakersfield Californian, District Sticks Drivers with Air Pollution Bill, October 21, 2010; http://www.bakersfieldcalifornian.com/local/x1485766515/District-sticks-drivers-with-air-pollution-bill; *see* also, San Joaquin Valley Pollution Control District, Air Alert 2011; http://www.valleyair.org/AirAlert/AirAlertMediaOverviewandRecap.pdf.

The alternatives analysis for the HECA Project must consider all of these public health and economic impacts.

III.A.2 The Alternatives Analysis Must Evaluate Impacts on Sensitive Populations, Including Children at Nearby Elk Hills School

One in six children in the San Joaquin Valley is diagnosed with asthma before the age of 18, an epidemic level.[29] Because of the poor air quality, children in Kern County are already restricted from playing outside many days of the year. The alternatives analysis must analyze the HECA Project's impacts on sensitive population including children as well as the elderly and residents with compromised health.

Further, the Elk Hills School is located only five miles from the HECA Project site. Children at Elk Hills School already experience dangerously elevated levels of air pollution on a regular basis. The alternatives analysis must evaluate air quality impacts and other impacts the plant might have on the Elk Hills School, such as emergency evacuation procedures.

III.A.3 The Alternatives Analysis Must Evaluate Impacts on Environmental Justice Communities

Adverse impacts of air pollution are not distributed equally in Kern County. Blacks and Hispanics experience somewhat more frequent exposures to elevated levels of fine particulate matter than non-Hispanic whites do.[30] A March 2012 study on health inequalities in the San Joaquin Valley found that life expectancy varies by as much as 21 years depending on zip code. The rate of premature deaths (years of potential life lost before the age 65) in the lowest-income zip codes of the San Joaquin Valley is nearly twice that of those in the highest-income zip codes. Additionally, areas of the San Joaquin Valley with the highest levels of respiratory risk have the highest percentage of Hispanic residents (55%), while areas with the lowest level of respiratory risk have the lowest percentage of Hispanic residents (38%).[31]

The District's alternatives analysis must fully analyze the impacts that the HECA Project would have on environmental justice communities surrounding the project site, the rail lines, as well as the areas around the roads that will experience heavy truck traffic. The project site is located close to the environmental justice communities of Tupman, Buttonwillow, and Wasco and the coal trains would run through southeast

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[29] Joint Center for Political and Economic Studies, Place Matters for Health in the San Joaquin Valley: Policy Brief, hereafter "Place Matters for Health", March 2012, p. 1; http://www.jointcenter.org/sites/default/files/upload/research/files/PM%20English.pdf.

[30] Benefits of Meeting Federal Clean Air, p. 3.

[31] Place Matters for Health, p. 1.

Bakersfield and negatively impact the environmental justice communities of Arvin and Lamont.

Coal is most commonly transported via open top rail cars, and these cars lose huge volumes of coal dust during transportation. Trucks carrying petcoke would similarly result in fugitive dust blowing from their open beds. Coal dust causes a number of well-known respiratory diseases, including pneumoconiosis (commonly known as Black Lung Disease), bronchitis and emphysema, and transportation of coal is identified by the Occupational Health and Safety Administration ("OSHA") as one of the methods for human exposure to coal dust.[32] Coal dust also contains varying amounts of heavy metals, including lead, mercury, chromium and uranium. Fugitive emissions of coal dust from transportation also cause increases in levels of coarse inhalable particulates in the air, which also present significant threats to human health. Apart from the direct health threats, fugitive coal dust along rail lines and near terminals can cause nuisance conditions for neighboring businesses and residences, resulting in economic losses due to the need for frequent cleaning.

Diesel emissions from transportation of coal, petcoke and products via both rail and truck also threaten to degrade air quality and impact human health. Fine particulate matter emissions associated with diesel engine exhaust can cause lung damage, aggravate respiratory disease such as asthma and diesel exhaust is known to cause cancer.[33] Diesel emissions have a high potential to impact people who are sensitive to the health effects of fine particles (*e.g.*, children, the elderly, and those with existing heart or lung disease, asthma or other respiratory problems).

For example, the small, rural community of Arvin in Kern County (south of Bakersfield) , which has 19,000 residents of which 93% are Latino or Hispanic[34], suffers from some of worst air quality in the nation. In addition to the persistent fine particulate matter pollution throughout the San Joaquin Valley, the community suffers from possibly more ozone violations than any other city in the country: every four days. The District expects Arvin to be the last place in the San Joaquin Valley to attain the federal 8-hour ozone standard.[35] Combustion emissions of ozone precursors from the heavy-duty diesel locomotives for rail transport of coal and truck transport of raw and waste

[32] OSHA, Occupational Safety and Health Guideline for Coal Dust (< 5% SiO_2); http://web.archive.org/web/20120925154038/http://www.osha.gov/SLTC/healthguidelines/coaldust-less5percentsio2/recognition.html.

[33] American Cancer Society, World Health Organization Says Diesel Exhaust Causes Cancer, June 15, 2012; http://www.cancer.org/cancer/news/news/world-health-organization-says-diesel-exhaust-causes-cancer.

[34] Wikipedia, Arvin, California; http://en.wikipedia.org/wiki/Arvin,_California.

[35] EPA, Community for a Better Arvin, CA, Environmental Justice (EJ) Grant; http://www2.epa.gov/sfbay-delta/community-successes#arvin.

materials as well as fugitive coal dust from the uncovered rail cars will further aggravate the existing, already extremely unhealthy air. The alternatives analysis must evaluate the impacts of fugitive coal dust, diesel soot, and other combustion pollutants on Arvin's overburdened population, as well as other communities along the rail line from New Mexico to Wasco.

As mentioned before, residents of the San Joaquin Valley airshed pay a fine to EPA for the poor air quality in the region via their annual vehicle registration. This fine disproportionally impacts members of low income communities. The District must consider how increasing air pollution and payment of this EPA-imposed fine impacts environmental justice communities.

III.B The Applicant's BACT Analysis for Alternative Generating Technologies Is Deficient Because It Does Not Adequately Consider Clean Fuel Alternatives

The Applicant's Application, upon which the PDOC relies, provides an analysis of alternative generating technologies under Clean Air Act Sections 52.21(j) and 51.165(a), which are implemented by SJVAPCD Rules 2410 and 2201.[36] This analysis is deficient because it failed to consider cleaner fuels such as natural gas, biomass, and alternative blends. The fundamental first step in a BACT analysis is to identify all available options for reducing emissions from a proposed source. A BACT analysis must include consideration of clean fuels to lower emissions limits. BACT is defined as "an emissions limitation based on the maximum degree of reduction achievable… through… [pollution control methods] including… clean fuels…"[37] As the Environmental Appeals Board has explained:

> [C]lean fuels are an available means of reducing emissions to be considered along with other approaches in identifying BACT level controls. EPA policy with regard to BACT has for a long time required that the permit writer examine the inherent cleanliness of the fuel.[38]

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[36] Application, Appx. B, Section 4.0.

[37] 42 U.S.C. § 7479(3); *see Sierra Club v. EPA*, 499 F.3d 653, 655 (7th Cir. 2007) ("The Act is explicit that 'clean fuels' is one of the control methods that the EPA has to consider."); *Hawaiian Elec. Co., Inc. v. EPA*, 723 F.2d 1440, 1442 (9th Cir. 1984) (low sulfur fuel likely to be BACT for a facility proposing to burn high sulfur fuel).

[38] *In re Inter-Power of New York, Inc.*, 5 E.A.D. 130, 134 (EAB March 16, 1994) (internal citations omitted); http://www.epa.gov/region7/air/nsr/nsrmemos/inter-p.pdf.

The Clean Air Act "promotes clean fuels with particular vigor."[39] Failure to conduct a proper clean fuels analysis is reversible legal error, and the Environmental Appeals Board has overturned many permits on this basis.[40]

III.B.1 Use of Cleaner Fuels Would Not Redefine the Source

The only limit on the Clean Air Act's clean fuel mandate recognized by the courts is where a fuel change would fundamentally change the physical scope of the project. In other words, the "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a different type of facility- such as substituting a power plant for a municipal waste combustor.[41] The Administrator in *Hibbing Taconite* explained that a change in fuel type does not redefine the source:

> Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project… [The redefining the source] argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (*e.g.*, "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice.[42]

Any other interpretation that avoids more stringent limits based on the Applicant's desires would allow the "redefining the source" exception to swallow the rule that clean fuels must be considered as part of BACT.

> [s]ome adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal… but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a control technology.[43]

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[39] *In re N. Mich. Univ.*, PSD Appeal No. 08-02, slip op. at 18-19 (EAB February 18, 2009), p. 27; http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Recent~Additions/06DBEC31EBFD8C3E852575620052318B/$File/Denying%20and%20Remanding...79.pdf.

[40] *In re Miss. Lime Co.*, PSD Appeal No. 11-01, at 17 (EAB August 9, 2011) (remanding PSD permit for failure to properly consider natural gas as BACT for startup fuel), http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/Decision~Date/8B66074F309B507C852578E70072E50F/$File/Remand%20Order...24.pdf; *In re N. Mich. Univ.*, PSD Appeal No. 08-02, slip op. at 18-19 (EAB February 18, 2009) (remanding permit for failure to properly consider burning more wood or lower sulfur coal as clean fuel); *Hibbing Taconite Co.*, 2 E.A.D. 838, 1989 WL 266359, *8 (EAB July 19, 1989) (remanding permit because agency failed to justify rejection of burning natural gas as a viable pollution control strategy); also found here: http://www.epa.gov/region7/air/nsr/nsrmemos/taconite.pdf.

[41] *In re Hibbing Taconite Co.*, 2 E.A.D. 838, 843 and n.12 (Adm'r 1989).

[42] *Id*. (emphasis added).

[43] *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007).

In such cases, BACT must be based on burning the cleaner fuel; otherwise permitting agencies would effectively "read [clean fuels] out of the definition of [best available control technology.]" *Id.*

The PDOC fails entirely to address alternative fuels in its BACT analyses for criteria pollutants. The PDOC's GHG BACT analysis adopts the Applicant's unjustified conclusion that petcoke and coal are "key project features" that are critical to the design of the source without any further analysis.[44] HECA cannot avoid the requirements of the Clean Air Act by narrowly defining the scope of the project or because it is receiving funding from the Department of Energy.

Further, the PDOC's description of feedstock for the Project is faulty on many different levels.

> Feedstock. Large amounts of petcoke are produced in California and exported overseas. Petcoke and coal are raw materials that are historically inexpensive per British thermal unit [Btu] and widely available in the U.S. A purpose of this project is to use these readily available traditional solid raw materials/fuels, and demonstrate their use for the generation of clean, low-carbon electricity.[45]

The fact that large quantities of petcoke are produced in California cuts against the HECA Project's current proposal to use only 25% petcoke and use 75% coal that has to be shipped over 600 miles from New Mexico.[46] Additionally, the claim that petcoke and coal are "historically inexpensive" ignores the historic low price point of natural gas, the low cost of biofuels, and the increasing cost of coal.

III.B.2 Natural Gas as Alternative Fuel

EPA recently held that BACT requires a coal gasification plant similar to the HECA Project, the Cash Creek Generation Project in Kentucky, to evaluate natural gas as a clean fuel.[47] EPA objected to the Cash Creek permit because "[t]he BACT analysis for this permit considers different technologies and fuels at different times in the plant's operation, but the analysis does not specifically include any consideration of using natural gas instead of syngas as the primary fuel."[48] EPA instructed that even if the

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[44] PDOC, Appx. I, p. 5.

[45] *Ibid*.

[46] Application, p. 2-23 and PDOC, p. 1.

[47] EPA, In the Matter of Cash Creek Generation, LLC, Order Responding to Issues Raised in January 31, 2008 and February 13, 2008 Petitions and Denying in Part and Granting in Part Requests for Objection to Permit, December 15, 2009, p. 7; http://www.epa.gov/region7/air/title5/petitiondb/petitions/cashcreek_response2008.pdf.

[48] *Ibid*.

agency ultimately chooses to reject the natural gas option, it still must provide a "reasoned explanation that demonstrates why the option of using exclusively natural gas is not 'available' for this facility."[49]

The PDOC's BACT analysis does not adequately consider the use of natural gas as an alternative fuel. Natural gas is a technically feasible and obvious option at HECA because the facility is designed to operate on natural gas both at startup and as a secondary fuel.[50] Instead of conducting a proper BACT analysis, the Applicant offers a legal opinion describing why it believes natural gas would redefine the source and provides an unsupported conclusion that natural gas would require substantial redesign of the facility.[51]

The Applicant states that many of the unit operations and processes that have been designed for HECA are specific to the use of coal/petcoke feedstocks, and to the removal of sulfur and CO_2 from the syngas, and the production of nitrogen-based products from the hydrogen-rich syngas and claims that use of natural gas as a feedstock would require substantial re-design of the facility.[52]

The Applicant, however, provides no discussion whatsoever why and how these processes would be affected to require substantial redesign of the facility. Sierra Club has previously asked the Applicant for information how exactly these processes would be affected but the Applicant refused to answer.[53] Some of the processes would not be necessary for a natural-gas fired facility including the solid fuel handling systems and baghouses, gasifier, sour shift/gas cooling, mercury removal, acid gas removal, sulfur recovery unit and tail gas treating unit, and flares for the sulfur recovery unit, gasification system, and Rectisol unit, and could simply be eliminated. Other processes including the CO_2 absorption and compression and the CO_2 pipeline could be equally implemented for a natural-gas fired facility.

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[49] *Id*., p. 8; *see also* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, EPA-457/B-11-001, at 27 (March 2011) ("any decision to exclude an option on 'redefining the source' grounds must be explained and documented in the permit record, especially where such an option has been identified as significant in public comments."); http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.

[50] PDOC, Appx. I, p. 15.

[51] Application, Appx. B, p. 13.

[52] *Ibid*.

[53] Michael Carroll, Latham & Watkins LLP, Counsel to Applicant, Applicant's Response to Sierra Club's Motion to Compel Production of Information in Response To Data Requests, Docket No. 08-AFC-8A, October 8, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-16_Applicant_Response_to_Sierra_Club_Motion_to_Compel_Production_of_Information_in_Response_to_Data_Requests_TN-67748.pdf.

In addition, the Applicant states that the combustion turbine used in this project has been specifically designed by Mitsubishi Heavy Industries ("MHI") to fire hydrogen-rich fuel and while it is capable of firing natural gas, different turbines/burners would be used if natural gas were the primary fuel.[54] Replacing a combustion turbine with a model that is optimized to burn natural gas would not constitute major redesign of the Project but merely require acquisition and installation of a different turbine. The Seventh Circuit has held that some changes to the preferred design must be considered or the term "clean fuels" would be meaningless.[55]

III.B.3 Alternative Fossil Fuel Blends

HECA originally proposed to use petcoke, a byproduct of the oil refining process, as its predominant feedstock.[56] The PDOC explains that large amounts of petcoke are produced in California, yet HECA's current proposal is to use a blend of 75% western subbituminous coal shipped 600 miles from New Mexico and 25% petcoke.[57] Clearly, gasification of petcoke is feasible and would provide benefits, yet the Applicant's BACT analysis fails to consider whether the project can use 100% petcoke, or a lesser percentage of coal than 75%, and is therefore deficient. Burning 100% petcoke or alternative blends of solid fuel in the same gasifier would not redefine the source and should be analyzed.

III.B.4 Biomass or Biomass Fuel Blend Alternative

Biomass can also be gasified or co-gasified with coal. Gasification of biomass or biomass co-gasification with coal would, for example, further reduce emissions of GHGs.[58] Not only would biomass gasification reduce direct emissions from the facility but it would also reduce emissions from open burning of biomass, which is a major contributor to air pollution in the Central Valley. In order to reduce those emissions, the District has asserted in the past that it would investigate gasification of biomass.[59] The SJVAPCD issued an ATC to Parreira Almond Processing Company in Los Banos, which

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[54] Application, Appx. B, p. 13.

[55] *Sierra Club v. EPA*, 499 F.3d at 656 ("Some adjustment in the design of the plant would be necessary… Otherwise 'clean fuels' would be read out of the definition of such technology.").

[56] Hydrogen Energy International LLC, Application for Certification, Hydrogen Energy California, July 2008 (hereafter "08-AFC-08"), p. 1-1; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/original_afc/Volume_01/Master_Section_1.0.pdf.

[57] PDOC, p. 1, and Application, p. 2-23.

[58] *See*, for example, World Coal Association, Co-firing Coal & Biomass, Ecoal, Vol. 70, March 2010; http://www.worldcoal.org/resources/ecoal-archive/ecoal---archive/co-firing-coal-biomass/.

[59] SJVAPCD, Receive and File Staff Report on Phase III to Rule 4103 (Open Burning), March 19, 2009; http://www.valleyair.org/board_meetings/gb/agenda_minutes/Agenda/2009/March/Agenda_Item_11_Mar_2009.pdf.

gasifies orchard trimmings into syngas that is used in a generator to produce electricity.[60] Most recently, Metso, a global supplier of technology and services in the process industry, supplied the equipment for a 140-MW biomass gasification plant in Finland which began operation earlier this year.[61] Clearly, biomass gasification or co-gasification with coal is feasible and must be evaluated in an alternatives analysis.

Further, biomass is readily available in the San Joaquin Valley and can be sourced locally,[62] unlike coal, which would be imported from New Mexico, and petcoke which would be imported from the Los Angeles and Santa Maria areas.[63] A proper BACT analysis must evaluate whether the gasifier can gasify biomass or a fuel blend with biomass.

IV. THE DISTRICT MAY NOT USE BANKED OFFSETS FOR THE HECA PROJECT AND HECA'S EMISSION REDUCTION CREDITS ARE NOT VALID

The PDOC proposes to offset the HECA Project's emissions with banked emission reduction credits ("ERCs"), *i.e.*, banked credits for the reduction of emissions that occurred at other facilities at some time in the past. Specifically, the PDOC proposes to offset NOx emissions with NOx ERCs, VOC emissions with VOC ERCs, and particulate matter emissions with SOx ERCs. As discussed in the comments below, the District may not allow HECA to use banked offsets because the federal Clean Air Act and local rules prohibit new sources from using banked offsets if an attainment plan has not been approved for the area. The District does not have an approved attainment plan for either the federal 1-hour ozone standard or the 2006 federal PM2.5 standard. Without these attainment plans in place, the District cannot assure that allowing these new emission increases is consistent with "reasonable further progress" towards attainment. Further, even if the District were permitted to use banked ERCs to offset emissions from the HECA Project, the discussion below shows that several of the proposed ERCs are invalid and do not meet the requirements of the District's rules and the federal Clean Air Act.

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[60] *See* California Air Resources Board, Air Quality Guidance for Siting Biorefineries in California, November 2011, p. 53; http://www.arb.ca.gov/fuels/lcfs/bioguidance/biodocs/finalbiorefineryguidenov2011.pdf.

[61] Metso, Metso-supplied World's Largest Biomass Gasification Plant Inaugurated in Finland, March 11, 2013; http://www.metso.com/energy/MPowerWArticles.nsf/WebWID/WTB-130403-22572-527D1?OpenDocument.

[62] *See,* for example, Biomass Fuel Supply Study for San Joaquin Solar 1 & 2 Power Plant; http://www.energy.ca.gov/sitingcases/sjsolar/documents/applicant/afc/AFC_volume_02/Appendix%20A%20Combined.pdf.

[63] Application, p. 2-23.

IV.A Nonattainment State Implementation Plan Requirements for Offsetting Emissions with Banked Emission Reduction Credits

EPA is required to designate each air basin in the country as "attainment" or "nonattainment" areas, depending on whether the basin meets the NAAQS for a particular pollutant.[64] Each state with a nonattainment area must develop, for review and approval by EPA, a State Implementation Plan ("SIP") that lays out how the state plans to achieve the respective NAAQS for each area.[65] Nonattainment plans must "require further reasonable progress," which is defined as "annual incremental reductions in emissions… for the purpose of ensuring attainment" of the NAAQS.[66] The first step is to compile a current inventory of actual emissions in the area and include enforceable emissions limitations, and such other control measures, means, or techniques, including offsetting requirements.[67]

SIPs must also include formal "attainment demonstrations," which show that the enforceable control measures included in the plan, measured against the projected emissions inventories, will result in air pollution reductions sufficient to bring the nonattainment area into attainment within a certain timeframe.[68] The emissions inventory and attainment demonstration must include the emissions from banked emissions reduction credits as if they were still in existence.[69] A major new stationary source must show that its emission increases will be consistent with "reasonable further progress" toward an area's attainment "by obtaining emission reductions of such air pollutant," from other sources in the nonattainment area to offset its emissions.[70] Emissions reductions must be permanent, federally enforceable, quantifiable and surplus to be valid.[71] Along with validity, to ensure reasonable further progress ("RFP")

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[64] 42 U.S.C. § 7407(d).

[65] 42 U.S.C. § 7410(a)(1).

[66] 42 U.S.C. §§ 7502(c)(3), 7501.

[67] 42 U.S.C. §§ 7502(c)(3),(6); 7410(a)(2)(A), (I).

[68] 40 C.F.R. § 51.112(a).

[69] 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) ("the attainment demonstration [must] include[s] the emissions from such previously shutdown or curtailed emissions units"); *see* generally *Emissions Trading Policy Statement: General Principles for Creating, Banking and Use of Emissions Reduction Credits*, 51 Fed. Reg. 43814, 43840 (Dec. 4, 1986) ("[i]f inventories do not treat these banked emissions as 'in the air,' or if they are otherwise relied upon for SIP planning purposes, such reductions can no longer be credited for trading."); *NRDC v. EPA*, 57 F.3d at 1276 (D.C. Cir. 2009).

[70] 42 U.S.C. § 7503(c).

[71] 40 C.F.R. §§ 51.165(a)(3)(ii)(C)(1)(i); 40 C.F.R. pt. 51, App. S § IV(C)(3)(i)(1); SJAVCD Rule 2301, § 3.8.

toward attainment, major new sources must meet additional requirements which vary depending on whether EPA has approved the area's attainment plan or not.[72]

The federal Clean Air Act allows major new sources of air pollution to be built in nonattainment areas only if the source can meet stringent requirements. The Act requires:

> by the time the source is to commence operation, sufficient offsetting emissions reductions have been obtained, such that total allowable emissions from existing sources in the region, from new or modified sources which are not major emitting facilities, and from the proposed source will be sufficiently less than total emissions from existing sources … prior to the application for such permit to construct or modify so as to represent … reasonable further progress … [73]

The federal rules implementing this provision distinguish between areas with and without approved attainment SIPs because "[b]y definition any fully approved SIP has independently assured RFP and attainment."[74] "However, with respect to those areas without the attainment demonstration mandated by section 172(a)(1), and therefore no independent assurance of RFP… it remains inappropriate… to attribute preapplication shutdowns to the construction of an unrelated new source for offset purposes."[75]

Banked credits cannot be used to offset emissions from new major stationary sources in a nonattainment area if that area does not have valid EPA-approved attainment plans in place. In *Natural Resources Defense Council* ("NRDC") *v. EPA*, the D.C. Circuit court confirmed that only areas with valid attainment demonstrations can meet the statutory requirements to "ensure[s] that emission reductions are achieved "*by the time*" the new source begins operation rather than sometime down the road after milestones have been missed." [76] (The court reversed a proposed EPA rule that eliminated the attainment demonstration requirement under certain circumstances because it was inconsistent with the statute.[77])

To summarize, if the nonattainment area has an attainment demonstration in place, then banked emissions reductions credits from pre-application shutdowns or

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[72] Compare 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) with 40 C.F.R. § 51.165(a)(3)(ii)(C)(2); *see* also *NRDC v. EPA*, 571 F.3d at 1245, 1266-1267 (D.C. Cir. 2009).

[73] 42 U.S.C. § 7503(a)(1)(A).

[74] *NRDC v. EPA*, 571 F.3d at 1266-67 (citing 54 Fed. Reg. at 27,292).

[75] 54 Fed. Reg. at 27,293; *see NRDC v. EPA*, 571 F.3d at 1267.

[76] *NRDC v. EPA*, 571 F.3d at 1267 (*emphasis* added).

[77] *NRDC v. EPA*, 571 F.3d at 1265.

permanent curtailments can be used to offset emissions increases from "an unrelated new source."[78] If the area lacks an attainment demonstration, however, only contemporaneous replacement capacity can be used to offset new emissions.[79]

San Joaquin Valley Rule 2201, 4.13.1 implements this requirement as follows:

> Major Source shutdowns or permanent curtailments in production or operating hours of a Major Source <u>may not be used as offsets for emissions from a Major Source</u>, a Federal Major Modification, or an SB 288 Major Modification, <u>unless the ERC, or the emissions from which the ERC are derived, has been included in an EPA-approved attainment plan</u>.[80]

IV.B Air Quality in the San Joaquin Valley

The San Joaquin Valley portion of the Central Valley has a long history of air pollution problems and has failed to achieve attainment with the California and national ambient air quality standards for ozone and fine particulate matter. Nowhere are the San Joaquin Valley's air pollution problems more pronounced than in the southern part of the valley between Stockton and Bakersfield, home to four million people. Bakersfield, less than 20 miles from the proposed project site, sits in a bowl surrounded on three sides by the Sierra Nevada and the California coastal ranges, which allows pollutants to build up. In 2013 the American Lung Association designated the City of Bakersfield the most polluted city in the country for particulate matter and the second most polluted city in the country for ozone. This pollution results in an astonishing number of 167,656 people at risk for cardiovascular disease, 68,419 people at risk for asthma, 25,296 people at risk for chronic bronchitis and emphysema in a population of about 851,710.[81]

With the HECA project, the District would permit a major new source of air pollution in an area where residents are frequently advised to stay indoors and homeowners prohibited to light their fireplaces during periods of high pollution. The location of the Project in the Bakersfield area would further exacerbate existing air pollution problems. Building a major new source of air pollution in one of the most polluted air sheds in the country will obstruct future progress towards reaching attainment with state and national ambient air quality standards and will contribute to adversely affecting the health of residents in the foreseeable future. ERCs generated by reducing pollution decades ago will do nothing to offset emissions from the Project. As

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[78] 54 Fed. Reg. at 27,293; 40 C.F.R. 51.165(a)(3)(ii)(C)(1)(ii); *NRDC v. EPA*, 571 F.3d at 1276.

[79] 40 C.F.R. 51.165(a)(3)(ii)(C)(2); *NRDC v. EPA*, 571 F.3d at 1276.

[80] (<u>Emphasis</u> added).

[81] American Lung Association, State of the Air 2013, 2013; http://www.stateoftheair.org/2013/assets/ala-sota-2013.pdf.

discussed below, some of the proposed offsets do not comply with applicable laws and regulations.

IV.C Lack of EPA Approval for Ozone and PM2.5 Attainment Plans for the San Joaquin Valley Prohibits Use of Banked Offsets

The San Joaquin Valley it is currently designated as extreme nonattainment with the 1-hour NAAQS for ozone and nonattainment with the 2006 annual NAAQS for PM2.5 but does not have EPA-approved attainment plans in place for either the 1-hour ozone or the annual PM2.5 NAAQS.

The San Joaquin Valley's history of ozone nonattainment is characterized by many years of missed deadlines and delays in crafting a plan toward achieving attainment. The history is detailed in the most recent court decision *in Sierra Club v. EPA*.[82] In brief, the San Joaquin Valley's designation has degraded from "serious" nonattainment in 1991 to "severe" in 2001, to its current "extreme" status in 2004.[83] The court invalidated the District's 2010 1-hour ozone plan because it was based on outdated data from 2004.[84] The San Joaquin Valley therefore currently does not have an approved attainment plan for the 1-hour ozone NAAQS. The District notes on its website that it expects to submit its new 1-hour ozone plan to EPA by June 2013.[85] The District may not permit HECA to use NOx and VOC ERCs to offset its ozone precursor emissions until this attainment plan is approved by EPA.

The San Joaquin Valley is also in nonattainment with fine particulate matter standards. The District has an attainment plan in place to achieve the 1997 federal standards for PM2.5, but not the 2006 standards.[86] Although the District and the California Air Resources Board ("CARB") recently approved the District's attainment plan to achieve the 2006 PM2.5 NAAQS, it has not yet been approved by EPA.[87] Thus, the District may not permit HECA to use banked ERCs for offsetting its PM2.5 emissions until the attainment plan is approved by EPA. Further, the proposed offsets are invalid and ineffectual as discussed in the following comments.

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82 671 F.3d at 955, 960-62 (9th Cir. 2012).

83 *Id*.

84 671 F.3d at 957-58.

85 SJVAPCD, Ozone Plans; http://www.valleyair.org/Air_Quality_Plans/Ozone_Plans.htm.

86 SJVAPCD, Particulate Matter Plans; http://www.valleyair.org/Air_Quality_Plans/PM_Plans.htm.

87 See 42 U.S.C. § 7410(k); *see* also 42 U.S.C. § 7502(c); 42 U.S.C. § 7410(h)(2).

IV.D Transaction History of HECA's Emission Reduction Credits

All ERCs proposed to offset emissions from HECA were derived as portions of ERCs from previous owners (*i.e.*, the prior certificate covered a larger amount of pollutant emissions and was subdivided so HECA could purchase only the portion they requested). We have summarized the history of these ERC through their various subdivisions and purchases from the original ERC owner to HECA based on a summary provided by the District and information provided in response to a public records request for the original ERCs:

- NOx: **S-3273-2** HECA (120,500/120,500/120,500/120,500 lbs/quarter) = portion of certificate <u>S-2183-2</u> procured from Big West (acquired by Alon Bakersfield Refining in 2010); originates with ***S-2007130/401 Alon Bakersfield Refining*** (method of reduction: shutdown of catalytic cracker, fluid coker, and CO boiler on November 30, 1983); subdivision/purchase chronology of ERC certificates: ***S-2007130/401*** → S-2007130/402 → S-2007130/403 → S-23-3 → S-124-2 → S-237-2 → S1652-2 → <u>S2183-2</u> → **S-3273-2**

- NOx: **C-1058-2** HECA (10,100/10,100/10,100/10,100 lbs/quarter) = portion of certificate <u>C-1052-2</u> procured from GIC Financial Services, Inc.; originates with ***C-1022-2 Guardian Industries Corp.*** (method of reduction: install SCR and scrubber and convert from fuel oil to natural gas on January 7, 2008); subdivision/purchase chronology of ERC certificates: ***C-1022-2*** → <u>C-1052-2</u> → **C-1058-2**

- SOx: **S-3275-5** HECA (42,000/42,000/42,000/42,000 lbs/quarter) = portion of certificate <u>S-2177-5</u> procured from Big West (acquired by Alon Bakersfield Refining in 2010); originates with ***S-2-5 Alon Bakersfield Refining*** (method of reduction: shutdown of tail gas incinerator on March 1, 1992); subdivision/purchase chronology of ERC certificates: ***S-2-5*** → S-1650-5 → <u>S-2177-5</u> → **S-3275-5**

- SOx: **C-1058-5** HECA (24,500/24,500/24,500/24,500 lbs/quarter) = portion of certificate <u>C-1052-5</u> procured from GIC Financial Services; originates with ***C-1022-5 Guardian Industries Corp.*** (method of reduction: install SCR and scrubber and convert from fuel oil to natural gas on January 7, 2008); subdivision/purchase chronology of ERC certificates: ***C-1022-5*** → <u>C-1052-5</u> → **C-1058-5**

- VOC: **S-3305-1** HECA (14,625/14,625/14,625/14,625 lbs/quarter) = portion of certificate S-3052-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S-3052-1 → **S-3305-1**

- VOC: **S-3557-1** HECA (11,437/11,438/11,438/11,437 lbs/quarter) = portion of certificate S-3306-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S3052-1 → S-3306-1 → **S-3557-1**

- VOC: **S-3605-1** HECA (7,937/7,938/7,938/7,937 lbs/quarter) portion of certificate S-3558-1 procured from Aer Glan Energy; originates with ***S-47-1 Frito-Lay, Inc.*** (method of reduction: shutdown of entire stationary source (Continental Carbon Corporation), December 1981); subdivision/purchase chronology of ERC certificates: ***S-47-1*** → S-156-1 → S-403-1 → S-1463-1 → S-1473-1 → S-1474-1 → S-1700-1 → S-2083-1 → S-2813-1 → S-2950-1 → S2993-1 → S3052-1 → S-3306-1 → S-3558-1 → **S-3605-1**[88]

The above summary shows that about 92% of the ERCs for NOx offsets were generated by the shutdown of a catalytic cracker, fluid coker, and CO boiler on November 30, 1983 and about 8% by the installation of a selective catalytic reduction system ("SCR") and scrubber and the conversion of the source from fuel oil to natural gas in 2008. Thus, the majority of NOx offsets proposed for HECA were generated close to three decades ago. About 63% of the ERCs for SOx used for PM10 offsets were generated by the shutdown of a tail gas incinerator on March 1, 1992, more than two decades ago, and about 37% from the installation of an SCR and scrubber and conversion from fuel oil to natural gas in 2008. All VOC ERCs originate from the shutdown of an entire stationary source in December 1981, *i.e.*, more than three decades ago.

[88] Information on the method of reduction that resulted in the original ERCs was provided by the Applicant in Amended AFC, Appx. E-10; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/amended_afc/Vol-III/Appendix_E.pdf. Information on dates when the original ERCs were generated was based on a public records request for ERCs S-3305-1, S-3557-1, and S-3605-1 and on information provided by the Applicant in response to April 12, 2010 CEC workshop request #26 (Attachment 26-1 email to Will Walters/CEC); http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/responses_2010-04-12_dr/04-Air_Quality_24-36.pdf.

IV.E HECA'S 30-Year Old Proposed Offsets Conflict With the Clean Air Act

Allowing offset credit for pre-application shutdowns and curtailments is contrary to the plain meaning of the Clean Air Act. Section 173(a)(1)(A) requires that "sufficient offsetting reductions" shall be obtained "such that total allowable emissions from existing sources in the region, from new or modified sources which are not major emitting facilities, and from the proposed source will be sufficiently less than total emissions from existing sources ... prior to the application for such permit to construct or modify so as to represent ... reasonable further progress."[89] Section 173(c)(1) requires that offsets come from "an equal or greater reduction, as applicable, in *actual emissions* of such air pollutant from the same or other sources in the area."[90]

Allowing HECA to use offset credit from reductions in emissions resulting from the shutdown or curtailment of operations from more than three decades ago is inconsistent with CAA § 173(c)(1)'s requirement that new sources' emissions "shall be offset" by an equal or greater reduction in "actual emissions."[91] The plain meaning of the word "actual," is "existing or occurring *at the time*."[92] The 30-year old offsets proposed for HECA are not "actual" emissions reductions that ensure "reasonable progress" toward attainment of the NAAQS or provide a positive net air quality benefit in the area affected by the proposed source.[93]

IV.F HECA's VOC ERCS Are Not Valid

HECA proposes to offset its VOC emissions with ERC certificates S-3305-1, S-3557-1, and S-3605-1. These ERCS suffer from so many legal deficiencies it is difficult to know where to start. The District needs to explain step-by-step how these ERCS could possibly be legitimate. The ERCs are not valid because they were not in conformance with the District rules or the Clean Air Act when generated more than three decades ago. At various points in time during the last 30 years, they were erroneously quantified and discounted and also traded in violation of restrictions on their use. Any one of these reasons makes these ERCS unlawful to use as offsets for emissions from the HECA Project.

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[89] 42 U.S.C. § 7503(a)(1)(A).

[90] *Id.* § 7503(c)(1) (*emphasis* added).

[91] 42 U.S.C. § 7503(c)(1).

[92] Merriam Webster, http://www.merriam-webster.com/dictionary/actual; *see Engine Mfrs. Ass'n v. S. Coast Air Quality Mgmt. Dist.*, 541 U.S. 246, 252, 124 S.Ct. 1756, 158 L.Ed.2d 529 (2004).

[93] US EPA, New Source Review Workshop Manual, ("NSR Manual"), p. G.6; http://www.epa.gov/NSR/ttnnsr01/gen/wkshpman.pdf.

IV.F.1 VOC Certificate History

As summarized in Comment IV.D. above, ERC certificates S-3305-1, S-3557-1, and S-3605-1 can be traced back through various transactions to ERC certificate S-47-1 held by Frito-Lay, Inc. ("Frito-Lay"). To summarize, the original ERC certificate S-47-1 held by Frito-Lay was reissued, subdivided, and changed hands a number of times from:

S-41-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-156-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-403-1 Frito-Lay (229,968/232,523/235,078/235,078 lbs/quarter) to
S-1463-1 Oceanair Environmental (175,000/175,000/175,000/175,000 lbs/quarter) to
S-1473-1 National Offsets (87,500/87,500/87,500/87,500 lbs/quarter) back to
S-1474-1 Oceanair Environmental (87,500/87,500/87,500/87,500 lbs/quarter) to
S-1700-1 Avenal Power Center (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2083-1 Duke Energy North America (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2813-1 Avenal Power Center (87,500/87,500/87,500/87,500 lbs/quarter) to
S-2950-1 Aer Glan Energy (75,000/75,000/75,000/75,000 lbs/quarter) to
S2993-1 Aer Glan Energy (74,250/74,250/74,250/74,250 lbs/quarter) to
S3052-1 Aer Glan Energy (61,750/61,750/61,750/61,750 lbs/quarter) to
S-3305-1, S-3357-1, 3605-1 HECA (combined 33,999/34,001/34,001/33,999lbs/quarter).[94]

IV.F.2 VOC ERCs Were Not Generated in Conformance with Applicable Federal Clean Air Act Provisions for Emission Reductions from Facility Shutdown

Review of the District's file for ERC certificate S-47-1 shows that the associated VOC emission reductions were generated by the shutdown of the Continental Carbon Corporation ("CCC") black carbon facility at 20807 Stockdale Highway, 8 miles west of Bakersfield in December 1981.[95,96,97] Frito-Lay (then doing business as The Food Company) purchased the permits to operate ("PTOs") for the CCC facility on July 1, 1982 with the intent to surrender these PTOs to the air district in exchange for being

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[94] Information from file "ERC History for HECA ERC.docx" provided by Jim Swaney, SJVAPCD, with email to David Abell, Re: Public Record Request C-2013-2-44: ERC for HECA, February 15, 2013; hereafter (Exhibit A").

[95] Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983, hereafter ("Exhibit B").

[96] *See*, for example, San Joaquin Valley Unified Air Pollution Control District, ERC Application Review, Frito-Lay, Inc., December 16, 1992, pp. 2 and 4, hereafter "Exhibit C - December 16, 1992 ERC Application Review".

[97] KCAPCD, Letter to David Howecamp, EPA, Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay, July 24, 1991 ("December 1981 shutdown of the Continental Carbon Black production stationary source"), hereafter ("Exhibit D").

permitted to offset emissions from its planned new 100-acre salty snack food manufacturing facility at 222801 Highway 58, 15 miles west of Bakersfield.[98,99]

The air district in charge at the time, *i.e.*, Kern County Air Pollution Control District ("KCAPCD") (later subsumed into SJVAPCD), informed Frito-Lay that the CCC PTOs could be used for offsetting emissions for their new snack food facility[100] (to be located about six miles from the CCC facility[101]) as long as Frito-Lay maintained the CCC PTOs in active status with the District.[102] At the time, when Frito-Lay and CCC entered into their agreement for sale of the black carbon facility, KCAPD Rule 210.1 allowed for offsets but the District apparently did not have an offset banking rule in place.[103] Instead, KCAPCD recognized in writing that the VOC emission reductions from shutdown of the CCC facility were valid ERCs.[104] Later that year, KCAPCD issued draft authorities to construct ("ATCs") to Frito-Lay for its new facility.[105]

However, on November 7, 1983, after review of Frito-Lay's draft permits, EPA expressed concerns regarding KCAPCD's interpretation of its offset rule (KCAPCD Rule 210.1, Sections 5.B.5 and 5.B.9), specifically that emission reductions from prior shutdowns location were not permitted for use as offset credits for off-site use.[106] While KCAPCD staff had apparently initially identified the same concerns during preliminary discussions with Frito-Lay in the spring of 1982, it later changed its position "based on discussions with the applicant and its legal counsel."[107] On November 10, 1983, KCAPCD communicated its disagreement with EPA's concerns over interpretation of KCAPCD Rule 210.1, Sections 5.B.5 and 5.B.9.[108] After a joint meeting with the District and Frito-Lay on April 4, 1984, EPA provided a resolution to the conflict in an April 10,

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98 *Ibid*, p. 4.

99 H.C. Bradbury, The Food Company, Letter to Tom Paxson, KCAPCD, September 13, 1982, hereafter (Exhibit E").

100 Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

101 Exhibit D, KCAPCD, Letter to David Howecamp, Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay, July 24, 1991 ("Continental Carbon Black production stationary source located approximately six miles from the Frito-Lay facility").

102 Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

103 Rule 210.1, Amended September 12, 1979, hereafter ("Exhibit F").

104 Exhibit B, Letter from T. Paxson, KCAPCD, to H.C. Bradbury, Frito-Lay, February 25, 1983.

105 *See*, for example, Exhibit C - December 16, 1992 ERC Application Review, p. 4.

106 Leon Hebertson, KCAPCD, Letter to David Howecamp, EPA, November 10, 1983, hereafter ("Exhibit G").

107 *Ibid*.

108 *Ibid*.

1984 letter to KCAPCD. In this letter, EPA reiterated its position that off-site use of shutdown credits did not conform with then applicable provisions of 40 CFR 51.8(j)(iii)(2)(c) but acknowledged that all involved parties acted in good faith and therefore it would not require revision of the permits provided that "CCC emissions and Permits to Operate can only be used by Frito-Lay for the snack foods processing plant at their present site and may not be sold or traded."[109]

The VOC ERCs associated with shutdown of the CCC carbon black facility are therefore not valid because they were not legal when they were first accepted as ERCs by the District. The documentation shows that they were not generated in conformance with the then applicable provisions of the District's Rules or the Clean Air Act. EPA agreed not to challenge them as illegal at the time only because there was originally an explicit restriction that they could never be sold or traded.

IV.F.3 Frito-Lay's ERCs Were Unlawfully Sold

In March 1992, Frito-Lay submitted an application requesting that the remaining ERCs be banked pursuant to the newly updated SJVAPCD Rule 230.1.[110] The District issued ERC certificates to Frito-Lay (shown for ERC certificate S-0047-1[111]) with the following restriction:

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-1

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

The banked ERC certificate prohibited their use by any major source or modification except for the Frito-Lay facility. Contrary to this clear prohibition, Frito-Lay (dba Recot, Inc.) then proceeded to transfer a large portion (175,000 lbs/quarter) to Oceanair Environmental (S-1463-1) in July 2000.[112] This transaction was unlawful for at least two reasons: it was contrary to the restriction included in the ERC certificate itself as well as EPA's explicit instructions to never sell

[109] David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984. (Emphasis added), hereafter ("Exhibit H").

[110] H.C. Bradbury, Frito-Lay, Inc., Letter to David Crow, KCAPCD, Re: Frito-Lay, Inc., Kern Production Facility Emission Reduction Credit Certificate(s), April 13, 1992, hereafter ("Exhibit I").

[111] *See* ERC certificates for Frito-Lay cancelled on September 24, 1993 (consumed by S-158-1), provided by SJVAPCD in response to Public Records Request, hereafter ("Exhibit J").

[112] *See* transaction summary in Comment IV.D above and ERC certificate documentation obtained from Homero Ramirez, SJVAPCD, with email to Petra Pless, Re: ERC Project S-1011223, May 21, 2013, hereafter ("Exhibit K").

or trade these offsets,[113] perpetuating the KCAPCD's initial error in interpreting its rules in compliance with applicable Clean Air Act provisions at the time. In December 2001, Oceanair transferred a portion of the ERC (87,500 lbs/quarter) to Duke Energy Avenal, LLC (S-1700-1).[114]

When Sierra Club questioned the District about these transactions, the District stated that the transfer of the ERC certificate to Oceanair was permissible because the emissions were included in the attainment plan.[115] The District, however, may not simply "legalize" ERCs by including them in an attainment plan. Further, Sierra Club obtained a copy of the corresponding ERCs and cancellations from the District.[116] The language restricting the use of the ERCs for use at Frito-Lay's snack food facility was only removed with the transaction from OceanAir to Duke Energy Avenal in December 2001. Thus, the transfer from Frito-Lay to Oceanair still carried the restriction. The District's accompanying ERC Transfer of Ownership Review does not provide an explanation why the language was removed and why the ERCs were deemed valid for use at Avenal.

IV.F.4 Emission Reduction Credits for S-41-1 Were Incorrectly Quantified and Are Therefore Not "Quantifiable" as Required by District Rules 2201 and 2301

Emission reductions must be *real*, *surplus*, *permanent*, and *quantifiable* pursuant to District Rule 2201, Section 3.2.1 and District Rule 2301, Section 4.1.1. The VOC ERCs from shutdown of the CCC facility are not *quantifiable* because the District overestimated emissions by averaging emissions over 8 years of operations between 1972 and 1979 instead of adhering to the EPA's clear instructions to use only the past two years (when at the CC facility emissions had significantly decreased compared to the prior 6 years.) The District also potentially overestimated emissions from the CCC facility by using generic emission factors from EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42") for carbon black facilities instead of facility-specific VOC emission factors determined during the source test at the facility[117] and thereby potentially overestimated ERCs available to Frito-Lay by a substantial amount.

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[113] Exhibit H, David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984.

[114] *See* transaction summary in Comment IV.D above.

[115] Phone conversation Petra Pless with Homero Ramirez, SJVAPCD, May 21, 2013.

[116] Exhibit K, Attachments to Homero Ramirez, SJVAPCD, Email to Petra Pless, Re: ERC Project S-1011223, May 21, 2013.

[117] Exhibit C, December 16, 1992 ERC Application Review. The Districts also accounted for a 29.5% reduction in emissions of VOCs to reflect recycle of main process vent gases installed in 1978 as determined in a source test.

Average Annual Production Rate

First, in relying on an 8-year average annual production of the CCC facility between 1972 through 1979, the District knowingly acted in defiance of EPA's explicit instructions to use a 2-year average:[118]

> In addition, the calculation of credits from a shutdown *cannot* be based on permitted emissions but must be based on actual emissions (*i.e.* the average rate at which the unit actually emitted during the two year period immediately preceding the shutdown). EPA expects that the District's commitment to these requirements will prevent any further misunderstandings.

Use of this 8-year average between 1972 through 1979 overestimated actual emissions from the CCC facility because the facility considerably reduced its production prior to the acquisition of their PTOs by Frito-Lay, as shown the following table.[119]

BAKERSFIELD PLANT PRODUCTION

YEAR	TREAD	CARCASS	TOTAL
1981	8,897,300 lbs.	7,263,200 lbs.	16,160,500 lbs. (8 mos. + 10 days = .6932 yr.)
1980	11,777,100 "	15,452,300 "	27,229,400 "
1979	21,116,800 "	27,492,600 "	48,609,400 "
1978	20,848,100 "	24,922,400 "	45,770,500 "
1977	30,000,300 "	25,828,200 "	55,828,500 "
1976	18,703,000 "	21,786,500 "	40,489,500 "
1975	24,327,900 "	25,190,700 "	49,518,600 "
1974	32,349,100 "	26,538,000 "	58,887,100 "
1973	32,037,800 "	30,009,200 "	62,047,000 "
1972	29,294,000 "	27,865,100 "	57,159,100 "
Averages	22,935,140	23,234,820	46,169,960 lbs. (avg. 9.6932 yrs)
Averages	24,494,900	25,009,444	49,504,344 lbs. (avg. 9 yrs-'72 thru '80)
Averages	26,084,625	26,204,087	52,288,712 lbs. (avg. 8 yrs - '72 thru '79)

By 1980, the CCC facility had reduced its carbon black production to about half of the 8-year average from 1972 through 1979 and by 1981 the facility only operated for

[118] Exhibit H, Excerpted from David Howecamp, EPA, Letter to Leon Hebertson, KCAPCD, April 10, 1984 (*emphasis* retained); note EPA's emphasis on "*cannot.*"

[119] Excerpted from SJVAPCD, ERC Application Review, August 21, 1992, p. 12, hereafter ("Exhibit L").

8 months before it shut down. The table also shows that the District had analyzed three average production scenarios: the 10-year average from 1972 through 1981; the 9-year average from 1972 through 1980; and the 8-year average from 1972 through 1979, settling on the highest of these average production rates rather than a conservatively low production rate.

VOC Emission Factors

Second, the District should have used the facility-specific VOC emission factors determined during the source test at the facility rather than generic AP-42 emission factors for carbon black facilities. The District's use of average AP-42 emission factors for the main process vent may considerably overestimate VOC emissions from the facility. Review of EPA's AP-42 document shows that the average value of 100 lbs VOC/ton carbon black for the main process gas vent was based on source testing at only one carbon black plant.[120] The document also provides a range of emission factors of 20 to 300 lbs VOC/ton carbon black based on a survey of fifteen other plants. The District did not discuss why it deemed the average value of 100 lbs/ton carbon black representative for quantifying emissions from the CCC facility rather than the lower end of the range of 20 lbs VOC/ton carbon black. Analogous to the potential to emit calculations discussed in Comment VII, the District should have used a conservative approach, *i.e.*, in this case the lowest emission factor.

IV.F.5 VOC ERCs Were Not Reduced to Account for Emissions from Frito-Lay Facility and Expansion

While the facility was required to donate a portion of its VOC ERCs (2,221.4 lbs/day) to the District, none of the VOC emission increases associated with Frito-Lay's snack food facility (38.5 tons/year) and its later expansion were offset with the CCC ERCs (as shown in the following excerpt from the District's ERC Application Review), presumably because the VOC emission increases were below the then applicable major source threshold of 100 tons/year:[121]

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[120] *See* Exhibit L, SJVAPCD, ERC Application Review, August 21, 1992, p. 9: Footnote e to AP-42, 5/83, Table 5.3-3.

[121] Exhibit C, For example, Lance Ericksen, SJVAPCD, ERC Application Review, December 16, 1992, p. 13; and Michael Barr, Pillsbury, Madison & Sutro, Letter to Leon Hebertson, KCAPCD, Re: Frito-Lay, Inc. – Air Pollution – Highway 58 Project, Kern County, California, November 12, 1987, attached Tables 1 and 2; *see* columns "HC.", hereafter ("Exhibit M").

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:

	Pounds/Day				
	PM10	SO2	NO2	VOC	CO
Actual Reductions	560.1	4773.6	687.2	4776.6	131,848.2
Used for Snack Food Facility Offsets	282.5	303.0	479.4	-	-
Donated to District	-	2673.9	-	2221.4	130,848.2
Balance Surplus Reductions	277.5	1796.7	207.8	2555.2	1,000.0

The District did not later require Frito-Lay to offset its VOC emissions when it promulgated a lower major source threshold at 20,000 lbs/year with Rule 2201, Section 3.24.1. In other words, Frito-Lay was permitted to increase its VOC emissions without ever using any of their unlawfully created offsets and, what's more, subsequently profiting from their equally unlawful sale. The District now proposes to offset further VOC emissions increases from the HECA Project with these same ERCs. To summarize: the VOC ERCs were created to account for emission reductions from a source that presumably would have shut down anyways, additional VOC emissions of 38.5 tons/year are being released by Frito-Lay's snack food facility[122] (and more from facility expansions) without using any of the VOC ERCs generated by shutdown of the CCC facility, thus resulting in a substantial net increase of ozone precursors into the airshed. Now HECA is proposing to release an additional 37.7 tons/year (75,379 lbs/day) of VOCs,[123] using only a portion of the originally created VOC ERCs.

Clearly, the use of decades-old emission reductions based on theoretical calculations which maximized their quantity can only provide a fictitious benefit to the airshed's actual air quality. It is not surprising that the District remains in extreme ozone non-attainment.

[122] Exhibit M, Michael Barr, Pillsbury, Madison & Sutro, Letter to Leon Hebertson, KCAPCD, Re: Frito-Lay, Inc. – Air Pollution – Highway 58 Project, Kern County, California, November 12, 1987, attached Tables 1 and 2; *see* columns "HC."

[123] PDOC, Table "Post-Project Stationary Source Potential to Emit [SPPE2] (lb/year)," p. 93.

IV.G Proposed PM10 Offsets Are Not Adequate

The PDOC's proposal to offset PM10 emissions with SOx ERCs fails to take into account that the location of PM10 offsets does not coincide with PM10 ambient concentrations resulting from Project emissions and that SOx emissions convert to PM10 at different rates during summer and winter.

IV.H Proposed PM2.5 Offsets Are Not Adequate to Mitigate the Project's PM2.5 Emissions

District Rule 2201, Section 4.14.1 requires:

> Emissions from a new or modified Stationary Source shall not cause or make worse the violation of an Ambient Air Quality Standard. In making this determination, the APCO [Air Pollution Control Officer] shall take into account the increases in minor and secondary source emissions as well as the mitigation of emissions through offsets obtained pursuant to this rule.[124]

The District modeled ambient concentrations resulting from direct PM2.5 emissions pursuant to SJVAPCD Rule 2201, Section 14.4.1,[125] and found that Project emissions would contribute significantly to existing exceedances of the 24-hour and annual NAAQS and the 24-hour CAAQS for PM2.5.[126] Modeled ambient concentrations of 24-hour PM2.5 of 3.1 $\mu g/m^3$ exceed the applicable significant impact levels ("SILs") of 1.2 by a factor of more than 2.5; modeled ambient concentrations of annual PM2.5 of 0.6 $\mu g/m^3$ exceed the applicable SIL by a factor of two.[127]

Due to these modeled exceedances, the District requires offsets for the full amount of the Project's PM2.5 emissions and proposes to mitigate the HECA Project's PM2.5 emissions with SOx interpollutant offsets using ERC certificates #S-3275-5 (SOx) and #C-1058-5 (SOx).[128,129] (As discussed before, about 63% of these ERCs were generated by the shutdown of a tail gas incinerator in 1992, more than two decades ago, and about 37% from the installation of an SCR and scrubber and conversion from fuel oil to natural gas in 2008.) The District finds that the use of these offsets would fully

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124 (Emphasis added).

125 PDOC, pp. 120-121 and 142.

126 PDOC, Appx. K, p. 49.

127 PDOC, Appx. K, p. 49.

128 PDOC, p. 122.

129 PDOC, p. 117.

mitigate the Project's impacts on air quality.[130] This conclusion is unsubstantiated for a number of reasons.

IV.H.1 Emission Reduction Credit Certificate #C-1058-5 (SOx) Is Not Valid Because It Is Not Accounted for in an EPA-Approved PM2.5 Attainment Plan

As discussed before, all ERCs that are proposed for use for offsetting emissions from a new stationary source must be accounted for in a District's attainment plan as if they were still in existence.[131] EPA notes that it "cannot allow states to consider less than their full amount of banked deposits as 'in the air.' To do so could jeopardize air quality planning and attainment."[132] "If inventories do not treat these banked emissions as 'in the air,' or if they are otherwise relied upon for SIP planning purposes, such reductions can no longer be credited for trading."[133]

Attainment plans for PM2.5 adopted by the District include the 2008 PM2.5 Plan, which addresses progress towards attainment of the annual national ambient air quality standard for the 1997 PM2.5 standard of 15 $\mu g/m^3$ and the 2012 PM2.5 Plan, which addresses progress towards attainment of the 2006 24-hour national ambient air quality standard for PM2.5 of 35 $\mu g/m^3$. The District's 2008 PM2.5 Plan is EPA-approved and the 2012 PM2.5 Plan has recently been submitted for EPA approval but has not been approved yet.[134]

Review of the District's EPA-approved 2008 PM2.5 Plan shows that emissions associated with ERC certificate #C-1058-5 (SOx) were not accounted for in the District's inventory.[135] Thus, ERC certificate #C-1058-5 (SOx) is not valid for offsetting PM2.5 emissions from the HECA Project for purposes of demonstrating compliance with the annual NAAQS. The District does account for this ERC certificate under HECA's name in its updated 2012 PM2.5 Plan,[136] but this does not validate the use of this certificate for purposes of demonstrating compliance with the 24-hour NAAQS until the plan is officially approved by EPA.

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130 *Ibid*.

131 40 C.F.R. § 51.165(a)(3)(ii)(C)(1)(ii) ("the attainment demonstration [must] include[s] the emissions from such previously shutdown or curtailed emissions units"); NRDC, 571 F.3d at 1276.

132 51 Fed. Reg. at 43840.

133 *See* generally *Emissions Trading Policy Statement: General Principles for Creating, Banking and Use of Emissions Reduction Credits*, 51 Fed. Reg. 43814, 43840 (Dec. 4, 1986)).

134 SJVAPCD, Particulate Matter Plans; http://www.valleyair.org/Air_Quality_Plans/PM_Plans.htm.

135 The 2008 PM2.5 Plan, Appendix D, Table D-5 lists S-3275-5 under the previous owners' name and certificate numbers S-2183-2 Big West. Not listed in the 2008 PM2.5 Plan is the predecessor of C-1058-5.

136 The 2012 PM2.5 Plan, Appendix H, Table H-5 lists S-3275-5 under HECA's name.

IV.H.2 The District Must Demonstrate that Project Emissions Would Not Cause or Contribute to a Violation of Ambient Air Quality Standards

The District cannot allow HECA to use interpollutant offsets, *i.e.*, SOx ERCS to offset PM2.5 emissions, until it adequately demonstrates that emissions increases due to operation of the HECA Project will not cause or contribute to violations of the NAAQS or the CAAQS for PM2.5. SJVAPCD Rule 2201, Section 4.13.3.1 requires:

> Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.[137]

The District finds that the appropriate interpollutant ratio for SOx emission reductions to offset PM2.5 emission increases from the HECA Project is 1:1, based on chemical mass balance modeling and speciated rollback modeling as performed by the 2008 PM2.5 attainment plan.[138] However, EPA rejected this method in their 2011 action on the District's Revised 2008 PM2.5 Plan.[139] The District subsequently acknowledged EPA's criticism and in its more recent 2012 PM2.5 Plan – approved by the District on December 20, 2012 and the CARB on January 24, 2013 – determined, based on photochemical modeling, that PM2.5 emissions must be offset at a considerably higher SOx:PM2.5 interpollutant offset ratio of 4.1:1.[140] Yet, the PDOC fails to require this higher interpollutant offset ratio for PM2.5 emissions from the HECA Project.

The District argues that Rule 2201, Section 4.13.3.2,[141] restriction on the use of interpollutant offsets to those ratios established by EPA or approved into the SIP is not applicable because the proposed facility is not a major source of PM2.5.[142] This cannot be the case because the District is relying on the use of interpollutant offsets in its AAQI/HRA Report to support its conclusion that HECA Project emissions would not cause or make worse existing violations of PM2.5 ambient air quality standards.[143] In doing so, the District "shall … impose offset ratios equal to or greater than the

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137 (Emphasis added).

138 PDOC, p. 121.

139 SJVAPCD, 2012 PM2.5 Plan, Adopted December 20, 2012, p. H-3; http://www.valleyair.org/Air_Quality_Plans/PM25Plan2012/CompletedPlanbookmarked.pdf.

140 *Ibid*.

141 The PDOC incorrectly refers to Section 4.13.2.2.

142 PDOC, p. 121.

143 PDOC, p. 121.

requirements of this rule."[144] The appropriate ratio for SOx:PM2.5 interpollutant offsets was determined by the District at 4.1:1 via photochemical modeling and the District plans to achieve further reasonable progress toward attainment of the PM2.5 NAAQS by using this offset ratio. The PDOC's willful ignorance of this ratio for the HECA Project defies and obstructs the federal Clean Air Act's mandate to achieve "reasonable further progress" toward attainment.[145] Even though EPA has not yet approved the 2012 Plan, the District may not approve a new project that does not meet the conditions it believes are necessary to achieve attainment with the PM2.5 NAAQS.

Further, the 4.1:1 interpollutant offset ratio was developed for bringing the air basin in compliance with the annual NAAQS of 15 $\mu g/m^3$. On January 15, 2013, EPA promulgated a lower annual NAAQS of 12 $\mu g/m^3$ which the PDOC fails to acknowledge. The District must address compliance with this new NAAQS as well as with the annual CAAQS for PM2.5 of 12 $\mu g/m^3$ and determine the appropriate offset ratio.

Finally, the HECA Project would also emit substantial amounts of ammonia, NOx, VOCs, and SOx which are precursors for the secondary formation of PM2.5.[146] The PDOC neither acknowledges nor models or mitigates secondary PM2.5. By accounting for and offsetting only direct emissions of PM2.5, the District fails to demonstrate how HECA would not contribute substantially to the existing substantial exceedances of the NAAQS and CAAQS for PM2.5 in the project area (24-hour background: 196 $\mu g/m^3$ and 22 $\mu g/m^3$ annual).

V. THE PDOC'S POTENTIAL TO EMIT ESTIMATES ARE NOT ADEQUATELY SUPPORTED, UNDERESTIMATE THE PROJECT'S IMPACTS ON AIR QUALITY, AND THE PROPOSED COMPLIANCE CONDITIONS DO NOT ENSURE COMPLIANCE WITH EMISSION LIMITS

At the core of the federal Clean Air Act are the potential to emit calculations. The permitting authority must calculate what the emissions from a new facility will be in order to determine whether the new facility constitutes a major source of air pollution and triggers BACT, lowest achievable emission rate ("LAER") or maximum achievable control technology ("MACT") requirements. To do so, the permitting authority must first determine each new emission unit's "potential" to emit regulated pollutants of

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[144] SJVAPCD Rule 2201, Section 4.13.3.1 (emphasis added).

[145] Nonattainment plans must "require further reasonable progress," which is defined as "annual incremental reductions in emissions…for the purpose of ensuring attainment" of the NAAQS. 42 U.S.C. §§ 7502(c)(3), 7501. The first step is to compile a current inventory of actual emissions in the area and include "enforceable emissions limitations, and such other control measures, means, or techniques," including offsetting requirements. 42 U.S.C. §§ 7502(c)(3),(6); 7410(a)(2)(A), (I).

[146] SJVAPCD, 2012 PM2.5 Plan, p. 4-3.

concern, including but not limited to criteria pollutants and hazardous air pollutants ("HAPs"). The permitting authority then calculates the PTE for the entire project by adding up maximum potential emissions resulting from all emission units at the facility.[147] If this combined PTE for the stationary source – the District uses the term SPPE2 – for any pollutant is higher than the "significance threshold" for that pollutant identified in the applicable state implementation plan ("SIP"), then it triggers strict major source requirements for BACT and LAER.[148] If the pollutant is a HAP and the PTE is higher than the major source thresholds for individual or combined HAPs, then it triggers MACT requirements. If emissions are below these thresholds, then the facility is subject to the less stringent minor source requirements. Further, the emission rates determined through these calculations are also used in the modeling demonstration to determine air quality impacts for national ambient air quality standards, PSD increments, Class I, and health risk assessment purposes.

Here, the PDOC's PTE calculation for the Project did not include an adequate analysis of potential emissions resulting from unplanned startups, shutdowns, and malfunctions. In addition, as will be discussed below, the PDOC underestimated emissions of a number of pollutants from a number of units and omitted others. The District's failure to include all emissions in its PTE calculation violates the Clean Air Act's requirement of analyzing the facility's "maximum capacity to emit."

Under the Clean Air Act, the calculations underlying the draft permit, *i.e.*, the PTE calculations, must reflect the worst case emissions scenario and be enforceable from a practical perspective. The requirement that PTE be both maximum, or worst-case, and enforceable is reflected in the District's regulations. SJVAPCD Rule 2201, Section 3.27, states in relevant part:

> Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including pollution control equipment and restrictions in hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design

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[147] *See, e.g.*, SJVAPCD Rule 2201, Section 3.27 ("Potential to Emit: the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design.") and Section 4.10 ("Post-project Stationary Source Potential to Emit (SSPE2) shall be calculated, on a pollutant-by-pollutant basis, as the sum of the following: 4.10.1 The Potential to Emit from all units with valid Authorities to Construct or Permits to Operate at the Stationary Source, except for emissions units proposed to be shutdown as part of a Stationary Source Project.")

[148] A "significant" emissions increase in pollutant emissions includes, *inter alia*, an increase in the source's emissions of 100 tons/year of CO, 40 tons/year of SO_2, 40 tons/year of ozone precursors (VOCs or NO_x), 15 tons/year of PM_{10}, and "any emission rate" increase of any "regulated NSR pollutant" not expressly listed in the governing regulations in an area not determined to be in nonattainment for that pollutant. 40 CFR § 51.166(b)(23)(i); SJVAPCD Rule 2401 (incorporating 40 CFR § 52.21).

> only if the limitation or the effect it would have on emissions is incorporated into the applicable permit as an <u>enforceable</u> permit condition.[149]

In short, this provision requires first that PTE reflect the maximum capacity to emit a pollutant. It requires second that, to the extent that the applicant or agency claims that maximum capacity to emit is constrained in any way, the constraint must be explicitly set forth in the permit as a *physical or operational limit* – *i.e.*, a specific limit on fuel, hours of operation, or pollution control equipment operating parameters – that is practicably enforceable.

Courts have emphasized the need to ensure that any constraints assumed on potential to emit are grounded in enforcement reality.[150] The *Louisiana Pacific* court described PTE as "the cornerstone of the entire PSD program," and observed that allowing illusory and unenforceable limits to curtail PTE would create a loophole that could effectively wipe out PSD requirements entirely.[151] The same can be said of the MACT program with its parallel structure and process.

To be enforceable, a permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for the District, CEC, EPA, and citizens to determine whether the facility is complying with the condition.[152] Under the District rules, relevant case law, and EPA guidance,[153] the only limits that render a design limitation on emissions enforceable for purposes of PTE are specific restrictions on operation and design set forth in the permit, adherence to which can be verified by authorities.

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149 <u>Emphasis</u> added.

150 *United States v. Louisiana Pacific Corp.*, 682 F. Supp. 1122 (D. Colo. 1987). The specific holding of *Louisiana Pacific* – that limits on PTE must be federally enforceable – has been overruled by authority stating that the limits may also be "enforceable as a practical matter." However, the basic principles concerning PTE articulated in *Louisiana Pacific* remain standing. *See National Mining Ass'n v. EPA*, 59 F.3d 1351 (D.C. Cir. 2004) (holding that limits on PTE must be enforceable as a practical matter but need not necessarily be federally enforceable). *See also Weiler v. Chatham Forest Products*, 370 F.3d 339, 241 (2d Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there are legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels.")

151 682 F. Supp. at 1133.

152 *See Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995).

153 SJVAPCD Rule 2201, Section 3.27; *Louisiana Pacific*, *supra* and *Weiler*, *supra*; Terrell Hunt, Associate Enforcement Counsel, EPA, Air Enforcement Division, and John Seitz, Director, EPA, Stationary Source Compliance Division, *Guidance on Limiting Potential to Emit in New Source Permitting*, (June 13, 1989) ("EPA PTE Guidance").

The requirement that PTE calculations be enforceable through adequate permit limits was recently reaffirmed by the EPA Administrator in her objection to the Title V permit for BP's Whiting facility.[154] In that case, EPA agreed with the argument that the permit conditions were inadequate because they "require monitoring only, and do not specify measures by which emissions will be limited to prevent their exceeding the PSD/NNSR significance levels, should monitoring show that emissions exceed those levels." The measures necessary to limit the facility to the PTE calculations were not required by the permit "and, therefore, do not constitute federally enforceable limits that hold the facility's PTE below the … significance thresholds."[155]

In the present case, the PDOC's PTE calculations do not represent worst-case conditions and, further, the PDOC's compliance conditions do not assure compliance with the PTE as calculated, as discussed in the following comments for criteria pollutants and GHGs and Comment VII for HAPs.

V.A The PDOC's Potential to Emit Estimates Are Based on Unsupported Assumptions and the Applicant Admits that Project Design Is Not Finalized

The PDOC's estimates of the Project's PTE – and resulting conclusions regarding, for example, applicability of PSD or impacts on air quality and public health – are based on numerous assumptions regarding material balances, process streams, emission factors, etc. Many of these assumptions are unsupported in the record; others rely on information provided by the gasifier manufacturer MHI or by vendors for other equipment without being supported by vendor guarantees. This may not be as troublesome for review of a standard natural gas-fired combined cycle gas turbine facility where all equipment components are well known; however, for review of the HECA Project, which is a one-of-a-kind facility with new equipment and components that have never been tested before or never before in this combination, it is unacceptable. For example, the proposed MHI gasifier is a new type of oxygen-blown dry-feed gasifier with a two-stage operation that has never been tested before on this scale or the range of fuel blends that the facility expects.[156]

Finally, the PDOC's emission calculations and ambient air quality modeling rely on information provided by the Applicant that are not supported by vendor guarantees or credible emission factors derived via source tests at similar facilities and similar

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[154] EPA, Order Responding to Petitioners' Request that the Administrator Object to Issuance of State Operating Permit, *In re BP Products North America, Inc. Whiting Business Unit* (October 16, 2009).

[155] *Ibid*, p. 8.

[156] *See*, for example, HECA Response to Sierra Club Data Request No. 16.b: "… demonstration at scale must be incorporated into the experience base of MHI before the full range of feedstock flexibility can be determined ad guarantees can be made."

feedstocks. As such, many of the PDOC's assumptions are unsupported. Some examples include but are not limited to:

- Neither the PDOC nor the Application provide vendor guarantees to support emission factors, pollutant concentrations in exhaust gas, duration of various startup/shutdown phases, and other information "estimated" by the gasifier manufacturer MHI used to estimate criteria pollutant emissions from the HRSG and coal dryer during normal operations as well as during startup and shutdown.[157]

- The amount of mercury volatilized in the feedstock dryer was estimated by the equipment designer and manufacturer MHI and apparently provided to the Applicant in proprietary and confidential heat and material balances.[158] Unless MHI provides a vendor guarantee for the amount of mercury volatilized in the feedstock dryer, the PDOC cannot rely on the mercury emission rate for the feedstock dryer.

- Emission factors for ammonia emissions for the high pressure ("HP") and low pressure ("LP") absorber vents and the urea pastillation unit were derived from information provided by Casale Fluor for a different project, the SCS Puregen One project, and proportionally scaled for the HECA Project capacity. The vendor "expects" that the HECA Project would meet the assumed combined ammonia emission rate of 13.1 pounds per hour ("lbs/hr") for the HP and LP absorbers during normal and stable operations.[159] An expectation is not a guarantee and cannot be relied upon for emission rates from a process with no prior testing experience.

- For modeling of NO_2 concentrations resulting from Project emissions of NOx, the District makes a assumptions for the NO_2/NOx in-stack ratios for several pieces of equipment that are lower than the EPA-recommended default value of 0.5 that can be used without further justification. Several of the assumed ratios, specifically for the HRSG stack and coal dryer, are based on equipment vendor "engineering estimates with no written documentation or guarantees.[160]

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[157] For example, Application, p. 3-19, and PDOC, pp. 206-207, and Appx. C, p. C-2.

[158] HECA Response to Sierra Club Data Request No. 38.w, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

[159] HECA Response to Sierra Club Data Request No. 38.p and Attachment 38-5 thereto, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

[160] PDOC, Appx. K, p. 47.

- Startup/shutdown operations of the flare assume 4,600 lbs/hour SO_2 in the acid gas vented to the SRU flare and a 99.5% removal efficiency for the caustic scrubber.[161] There is no support for these assumptions.

- Many other instances of unsupported assumptions are discussed throughout the comment letter.

Because this is a one-of-a-kind facility that employs equipment which has not been tested at the same scale before (*e.g.*, gasifier) or in this combination and control technologies whose assumed control efficiency is very high (*e.g.*, combined efficiency of activated carbon adsorption beds of 99%), all vendor- or Applicant-supplied emission factors and other assumptions must be adequately supported by vendor guarantees and incorporated into enforceable permit conditions.

Further, the details of the Project appear to be still under revision. For example, in an April 10, 2013 email to the CEC, more than eight weeks after publication of the PDOC, the Applicant's consultant URS Corporation ("URS") acknowledged that in addition to coal and petcoke the facility would require substantial amounts of limestone as a fluxant (on the order of 175 tons/day and 59,000 tons/year), which would require a separate fluxant unloading facility and a storage silo equipped with a baghouse.[162] Use of this fluxant would generate an additional 88 tons/day of gasification solids (an increase of 10%)[163] that need to be disposed of.[164] The need for a fluxant has never been mentioned before for the revised HECA Project (using the MHI gasifier), which was submitted for review to the CEC over a year ago. Emissions associated with fluxant delivery, handling, and storage and increased gasification solids disposal activities are consequently not accounted for in the PTE calculated by the PDOC.

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[161] PDOC, p. 60, and 1/10/2013 HECA Updated Emission Data, "Flares – Emissions Summary" dated November 13, 2012, p. 11 of 32, pdf 44.

[162] Dave Shileikis, URS, Email to Robert Worl, California Energy Commission, Re: Requested Information Re: HECA, April 10, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-04-10_Applicant_URS_Email_Response_to_CEC_re_Requested_Information_about_MW_and_Limestone_Fluxant_TN-70376.pdf.

[163] (938 tons/day) / (850 tons/day) = 1.10.

[164] Dave Shileikis, URS, Email to Robert Worl, California Energy Commission, Re: Requested Information Re: HECA, April 10, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-04-10_Applicant_URS_Email_Response_to_CEC_re_Requested_Information_about_MW_and_Limestone_Fluxant_TN-70376.pdf.

The Applicant also acknowledges that it currently does not have a complete energy balance and states that it will take some time to prepare this balance.[165] At this point in time, the Applicant estimates that "[n]et output may range from 267–300 MW and gross output may range from 405–431 MW."[166] When the main material and energy balances for the HECA Project cannot even be relied upon and continue to be substantially revised, the Applicant's emissions estimates for the Project's various processes should be considered preliminary at best, especially when close to applicable thresholds and not adequately monitored. The District cannot accurately calculate the PTE for the Project, determine whether Project emissions exceed major source thresholds, or demonstrate that the Project complies with all applicable rules and regulations based on unreliable information that is still under revision. As such, the PDOC is premature and should be withdrawn until the Applicant is able to present detailed and stable material and energy balances as well as vendor guarantees that support all assumptions used for Project emission estimates.

V.B The Facility's Potential to Emit Is Underestimated and Emission Limits Are Not Adequately Enforced

As discussed in the comments below, the PDOC contains a number of potential to emit calculations that do not account for the facility's maximum potential emissions and many of the PDOC's emission estimates are not adequately translated into enforceable emission limits in compliance conditions. Sierra Club requests that the District revise the emission estimates for the HECA Project to address these substantial flaws, adequately establish the facility's PTE based on maximum potential emissions, and update its ambient air quality modeling and health risk assessment accordingly.

V.B.1 Flare Emissions during Unplanned Startup, Shutdown, and Malfunction Events Are Not Accounted For

Startup, shutdown and malfunction ("SSM") emissions must be strictly prohibited or included in the potential to emit.[167] A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flares due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, pressure surges, etc. The EPA recently objected to the proposed Title V and PSD

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165 *Ibid*.

166 *Ibid*.

167 *Weiler v. Chatham Forest Products*, 370 F.3d 339, 341 (2d Cir. 2004); EPA, Order Responding to Petitioners Request that the Administrator Object to Issuance of State Operating Permit from the EPA Administrator regarding BP Products North America, Inc., Whiting Business Unit, Permit No. 089-25488-00453, October 16, 2009. *See also* Steven C. Riva, EPA, Region 2, Letter to William O'Sullivan, New Jersey Department of Environmental Protection, February 14, 2006.

permit for the Cash Creek coal-to-synthetic natural gas facility in Kentucky because, amongst other issues, the permitting agency's determination of potential to emit for the facility did not account for unplanned shutdown and malfunction emissions from the flare.[168] EPA also objected to the proposed Title V permit for the Kentucky Syngas facility for failing to account for unplanned shutdown and malfunction emissions from the flare.[169]

While the PDOC accounts for planned startup/shutdown emissions, it takes an inconsistent approach for estimating PTE for the facility's various emission units with respect to unplanned startup/shutdowns and malfunction emissions. For emissions from the CO_2 recovery and vent system (S-7616-24-0), the PDOC calculates annual emissions based on 21 days/year (equivalent to a cumulative 504 hours/year) of venting at full capacity, accounting for two planned startup events per year and seven unplanned events per year including four unplanned CO_2 compressor outages, one unplanned CO_2 pipeline outage, and two unplanned events where the CO_2-offtaker is unable to accept.[170] The PDOC translates these assumptions into a permit condition restricting venting to a cumulative 504 hours per rolling 12-month average. Similarly, emissions from the HRSG when firing on natural gas during unplanned equipment outages are estimated based on a maximum of 336 hours per year and restricted by a corresponding condition of compliance.[171]

In contrast, the PDOC calculates maximum annual emissions based on flaring events during two planned startup events per year only.[172] The amount of annual flaring estimated by the PDOC is almost trivial: 28 hours for the gasification flare (startup and shutdown only); 40 hours for the SRU flare; and 40 hours for the Rectisol flare.[173] While the PDOC acknowledges that all three flares may dispose of gases during

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[168] EPA, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012, pp. 15-16; found on the internet at: http://www.epa.gov/region07/air/title5/petitiondb/petitions/cashcreek_response2010.pdf.

[169] EPA, In the Matter of Kentucky Syngas, LLC, Muhlenberg County, Kentucky, Title V/PSD Air Quality Permit No. V-09-001, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-9, June 22, 2012; found on the internet at: http://www.epa.gov/region07/air/title5/petitiondb/petitions/kentuckysyngas_response2010.pdf.

[170] PDOC, pp. 31, 81 and Appx. I, p. 9.

[171] PDOC, Appx. A, Condition 29, p. A-56.

[172] PDOC, pp. 58-61 and pp. 84-86.

[173] PDOC, pp. 84-86.

"emergency or upset" events,[174] the PDOC's calculations for flares do not account for emissions during any unplanned emergency events and therefore do not calculate maximum or worst-case PTE for the flares and the facility. Consequently, the PDOC's air quality modeling also did not include malfunction events and thus did not model the maximum offsite short-term impacts. This is particularly problematic for short-term SO_2 emissions and would likely result in exceedances of the 1-hour SO_2 NAAQS.

Because the PDOC restricts flaring events and sets emission limits only for planned flaring events and excludes malfunction events from the flaring emission limits,[175] exceedances of ambient air quality standards during malfunctions would never be discovered and reported.[176] The PDOC does also not contain any condition limiting the number and/or duration of unplanned startup/shutdown and malfunction events for either the gasifier, syngas scrubbing system, sour shift/low temperature gas cooling system, mercury removal system, or Rectisol acid gas removal unit which would vent to the three flares servicing the gasification unit (S-7613-30-0), the Rectisol unit (S-7616-31-0), and the sulfur recovery unit ("SRU") (S-7616-32-0).[177] Thus, flaring during upset conditions at these units could release large amounts of pollutants, without any restrictions. As malfunctions are by definition unplanned, the duration of the events and the amount and type of emissions could be very different than assumed for the planned startups and shutdowns.

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[174] *See* PDOC, pp 57-61: "Vessels, towers, heat exchangers, and other equipment are connected to piping systems that will discharge gases and vapors to a relief system in order to prevent excessive pressure from building up in the equipment during upsets and emergencies." "Flaring will occur … during emergencies." "The gasification flare will dispose of excess gas … during unplanned power plant upsets or equipment failures." "Flaring of untreated syngas or other streams will … occur as an emergency safety measure during unplanned upsets or equipment failures." "The SRU flare will be used to safely flare … gas streams containing sulfur during unplanned upsets or emergency events." "The SRU flare will … oxidize gas releases during emergency or upset events." "The Rectisol flare will be used to safely dispose of low temperature gas streams during … unplanned events or emergency events." "The maximum capacity of the Rectisol flare is based on the total flow from an … equipment failure event, such as a major failure in the acid gas removal unit." PDOC, Appx. A, Compliance condition No. 24, pp. A-80, A-87, A-95: "Other than the planned flaring limited in the condition above, this flare shall be operated solely for emergency situations, which are any situations or conditions arising from a sudden and reasonably unforeseen and unpreventable event beyond the control of the operator. Examples include, but are not limited to, not preventable equipment failure, natural disaster, act of war or terrorism, or external power curtailment, excluding a power curtailment due to an interruptible power service agreement from a utility…" (Emphasis added.)

[175] PDOC, Appx. A, pp. A-80, A-87, A-95, Compliance condition No. 19: Total time of planned flaring shall not exceed 8 hours per day nor 40 hours per calendar year." No. 20: "During planned flaring events, no more than 430 MMBtu/hr shall be combusted." No. 21: "Emissions from the flare during pilot and other non-emergency operation shall not exceed any of the following… [emission limits]." No. 22: SOx emissions from the flare shall not exceed 0.00214 lb/MMBtu during pilot gas combustion nor 15.0 lb/hr during other non-emergency combustion." (Emphasis added.)

[176] PDOC, Appx. A, pp. A-78-A-101.

[177] *See* PDOC, Appx. A, Compliance condition for Gasification System (S-7616-21-0), pp. A-21-A-26.

During unplanned flaring events, or malfunctions, syngas streams containing large amounts of sulfur could be sent to the flares including raw syngas, scrubbed syngas, shifted syngas, or sour syngas. For example, at full capacity, the acid gas vent to the SRU flare could emit up to 4,600 lbs/hour SO_2, *e.g.*, when the caustic scrubber experiences a malfunction.[178] The flares convert sulfur present in these syngas streams as H_2S and COS into SO_2, which could lead to exceedances of the 1-hour SO_2 NAAQS as well as short-term ambient air quality standards for other pollutants.

Unplanned releases due to emergency conditions have been widely documented in the coal gasification industry and are not rare occurrences. They occur as a result of harsh processing conditions unique to coal gasification due to high concentrations of substances that corrode, erode and foul processing equipment such as ash, slag, sulfur compounds, and various organic acids. These components cause overheating, plugging, corrosion, erosion, and fouling of common processing equipment such as heat exchangers, coolers, slag handling equipment, and pump, compressor rotors, impellers and blades; fouling and associated corrosion of heat exchangers and coolers.[179]

HECA claims that "[g]iven the reliability of the subject equipment, there are no anticipated malfunctions; therefore, no emissions associated with such events are included in the PTE."[180] In fact, contrary to HECA's assertion, there is likely to be considerable malfunction flaring at the HECA Project, especially during the first few years of operation, but this can also occur during mature operations. The facility must comply with all permit limits and not exceed PSD increments and NAAQS under all operating conditions. There has been no demonstration in the PDOC that this is feasible. In fact, by including a limit on natural gas firing for the HRSG for unplanned events of 336 hours/year,[181] the PDOC makes clear that substantial periods of malfunction of the gasification unit and/or other equipment involved in producing clean syngas are expected during which the HRSG would not receive and operate on clean syngas but

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[178] 1/10/2013 HECA Updated Emissions Data, "Flares – Emissions Summary," dated November 11, 2012, p. 11 of 32, pdf 44.

[179] Neville A.H. Holt, Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants, Materials at High Temperatures, v. 20, no. 1, pp. 1-6, 2003; W. Schellberg and others, World's Largest IGCC Celebrates 10th Anniversary, 25th Annual International Pittsburgh Coal Conference, September 29 - October 2, 2008; EPRI, Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions, December 2006; Neville A.H. Holt, IGCC Technical Status, Trends and Future Improvements, ACS Meeting, San Francisco, March 2000.

[180] HECA Response to Sierra Club Data Request No. 62, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-12_Applicants_Supplemental_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67706.pdf.

[181] PDOC, Appx. A, Condition 29, p. A-56.

instead would have to rely on natural gas as a backup fuel to keep the HRSG running.[182] Flaring emissions during these unplanned events must be accounted for.

For example, a reliability study by Siemens for the Taylorville Energy Center in Illinois indicates poor availability during the first two years of operation, 55 to 65% during the first year and 75 to 85% during the second year.[183] This indicates the potential for significant malfunction events during these first two years of operation.

The one operational IGCC plant in the world that uses the same MHI gasifier technology as HECA will use, the Nakoso IGCC in Japan, has a record of online availability that is not that different than that of other gasifier designs.[184] The Nakoso IGCC plant 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, such as the Tampa Electric Polk Power Station in Polk County, Florida, and the Wabash River Coal Gasification Repowering Project near West Terre Haute, Indiana.[185] The low availability is due in part to forced outages (aka malfunctions).

Regarding the availability of the Nakoso IGCC plant over time, HECA consultant URS states: "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 (since operation began in 2007) … Cumulative operating hours since commissioning has

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[182] See, *e.g.,* PDOC, p. 38: "Firing of the turbine on natural gas backup fuel will be limited to a maximum of … 336 hr/yr of unplanned equipment outages." PDOC, Appx. C, p. C-1: "The MHI 501 GAC® … turbine model … will fire on natural gas as a backup fuel … during periods of unplanned equipment outages up to 336 hours per year—periods when hydrogen gas is not available because the hydrogen-producing equipment is out of service." PDOC, Appx. C-6: "The backup natural gas firing will occur … during periods of unplanned equipment outages (up to 336 hours per year)" and "The permittee requests to fire the turbine/HRSG on natural gas for a limited period of time up to 336 hours per year when the gasifier is unavailable…" PDOC, Appx. I: "Firing on the backup natural gas fuel is necessary … during periods of unplanned gasification equipment outages for up to 336 hours per year (equivalent to 2 weeks per year) when hydrogen-rich fuel is unavailable."

[183] Siemens Operations and Maintenance Reliability Availability Maintenance Analysis, Taylorville Energy Center, February19, 2010, p. 3; http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.5%20-%20Siemens%20Operations%20and%20Maintenance%20Reliability%20Availability%20Maintenance%20Analysis.pdf.

[184] *See*, for example, Electric Power Research Institute, John Wheeldon, IGCC 101, Advanced Coal Gasification Technologies Workshop, Kingsport, April 25 and 26, 2012; http://www.gasification.org/uploads/downloads/Workshops/2012/Wheeldon,%20Kingsport.pdf.

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

exceeded 16,100 hours (as of April 2012)."[186] 16,100 hours operating hours from late 2007 through April 2012, excluding four and a half months for the tsunami outage, is 16,100 hours over approximately four calendar years (35,040 hours). Thus, the actual availability of the Nakoso IGCC plant through April 2012 averaged 46 percent availability over the first four full years of operation (through April 2012) ((16,100 hours)/(35,040 hours) = 0.46). Nakoso has definitely not been operating continuously. There is no reason based on the operating history at Nakoso to assume that HECA will not have frequent starts and stops due to forced outages.

It is typical for applications for gasification facilities to estimate malfunction-related emissions as a separate category from startup flaring emissions. For example, the application for the Southeast Idaho Power facility estimated the duration and frequency of events based on whether they were caused by upsets downstream, upstream, or at the acid gas removal unit, estimating a total of 92 hours of upsets per year.[187] Likewise, the FutureGen gasification project grouped and estimated upsets by source of the problem: the air separation unit, the gasifier, the acid gas removal unit, the Claus unit, or the power island; it further estimates annual upset frequency for each source type.[188] The permit application for the Medicine Bow, Wyoming, gasification project (which was also prepared by URS) estimates emissions from 48 hours of malfunction-related flaring per year.[189]

The application for the Power Holdings coal-to-synthetic natural gas ("SNG") project in Illinois also recognized that upset emissions will occur and made an effort to estimate those emissions. It found that gases sent to the flare during malfunction may be sent without cleanup. The Power Holdings application contains malfunction evaluations at many points, and it attempts to identify the requirements for including

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[186] HECA Responses to Sierra Club Data Request No. 116, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[187] Southeast Idaho Power, Permit Application, Appx. D, p. 34; http://www.deq.state.id.us/AIR/permits_forms/permitting/pcaec/app_d_0408.pdf.

[188] FutureGen Final Environmental Impact Statement, November 2007; Appx. E, pp. E-4 and E-5; http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/Appendix%20E%20-%20Air%20Modeling%20Protocol.pdf.

[189] Medicine Bow Fuel & Power LLC Industrial Gasification &Liquefaction (IGL) Plant, Carbon County, Wyoming, Prevention of Significant Deterioration Permit Application, December 31, 2007, Amended Permit Application, Appx. B (HP Flare Detail Sheet: 40 hours HP flare; LP Flare Detail Sheet: 8 hours LP flare); http://deq.state.wy.us/eqc/orders/Air%20Closed%20Cases/09-2801%20Medicine%20Bow%20Fuel%20&%20Power,%20LLC/Ex%2015.DEQ's%20Motion%20for%20Summary%20Judgment.pdf.

malfunction emissions and specific actions for reducing them.[190] The Power Holdings application modeled various malfunction scenarios as follows:

> The malfunction cases were evaluated in AERMOD. The modeling was conducted for both daytime and nighttime malfunction conditions. The three malfunction scenarios modeled were:
>
> - Malfunction case 4 - Unplanned shutdown of one methanation unit, sweet syngas to SNG flare for 60 minutes.
> - Malfunction case 5 - Unplanned shutdown of one Rectisol unit, sour syngas to SNG flare for 22 minutes (modeled as a 60 minute event).
> - Malfunction case 6 - Unplanned shutdown of one WSA unit, acid gas to acid gas flare for 22 minutes (modeled as a 60 minute event).
> - Malfunction cases 4, 5, and 6 represent the worst case malfunction events. Each malfunction scenario was setup for 23 hours of normal operations with one hour operating under one of the above listed malfunction condition. This operating situation was model as if it occurs every day during the 5 year period. This approached ensured that the highest 2nd high for each PSD review pollutants was identified.[191]

Malfunction scenarios can be identified and planned for using, for example, fault tree analysis or failure mode effect analysis, to identify possible failure modes in design, operation or maintenance. These types of analyses are used to design the flare system itself. The Applicant must have conducted such analyses, *e.g.,* to determine maximum capacity of the flares during malfunction events and to estimate a total of 336 hours of operation of the CTG on natural gas during malfunction events. Thus, emissions from the flares during such malfunction events can be estimated and included in potential to emit calculations, and air quality modeling. However, the PDOC in this case does not include the information required to estimate these emissions.

V.B.2 Combustion Turbine Generator/Heat Recovery Steam Generator and Coal Dryer Emissions Are Underestimated and Emission Limits Are Not Enforceable

The PDOC's emission estimates for the HECA Project's HRSG and feedstock dryer were based on an "expected operating schedule of 8,000 hours of operations, two startups and shutdowns per year, and 2 additional weeks of natural-gas operations

[190] PSD Construction Permit Application for the Southern Illinois Coal Gasification to Synthetic Natural Gas (SNG) Facility, Prepared for Power Holdings of Illinois, Southern Illinois Coal to SNG Facility, October 17, 2007, Chapters 1 and 2.

[191] Power Holdings of Illinois, Permit Application, pp. 1-130 to 1-131.

other than startup and shutdown events."[192] The duration of the HRSG startup and shutdown events is assumed at 4.5 and 9 hours, respectively; the duration of the coal dryer startup and shutdown events is shorter and assumed at 4 hours each.[193] Thus, the PDOC's PTE calculations account for 8,363 hours of operation per year for the HRSG under the various permitted operating conditions.[194] The PDOC explained that this operating schedule was chosen because "hours that include startup and shutdown events will have higher NOx, CO, and VOC emissions than the normal operating condition with fully functioning SCR and CO oxidation catalyst."[195] There are a number of problems with the PDOC's assumptions which result in a considerable underestimate of the facility's PTE for several pollutants which are not adequately restricted by other permit conditions.

The PDOC arbitrarily assumes that the HRSG and coal dryer would not operate for a total of 397 hours of the year[196] (presumably for maintenance after the annual two planned shutdown events) and have zero emissions during this period. In other words, the PDOC assumes that each of the two planned shutdowns would require 198.5 hours or about 8.25 days of maintenance.[197] The PDOC contains no explanation for its assumption of downtime and it does not translate the "expected operating schedule" into enforceable permit conditions. Specifically, while the PDOC contains permit conditions limiting a) the number (2/year) and duration of startups and shutdowns for both the HRSG (4.5 hours and 9.0 hours) and the coal dryer (4.0 hours and 4.0 hours),[198] b) the duration of HRSG operation on natural gas during periods other than startup and shutdown events to 336 hours (14 days),[199] and c) monitoring for NOx and CO via continuous emissions monitoring systems ("CEMS")[200] to demonstrate compliance with daily and annual emission limits, the PDOC does <u>not</u> contain d) a restriction on the total number of hours under normal operating conditions for the HRSG and the feedstock dryer, e) a requirement that the units not operate for 397 hours per year, or f) continuous monitoring for SOx, PM10, VOC, and ammonia mass emissions (rather than demonstrating compliance by calculation and source testing). Maximum emission

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[192] PDOC, p. 28.

[193] *See* 1/10/2013 HECA Updated Emissions Data, "HRSG and Coal Dryer," pp. 2-4 of 22, pdf 35-37.

[194] (8,000 hours/year normal operation) + (2 × 4.5 hours/year HRSG startup conditions) + (2 × 9 hours/year HRSG shutdown conditions) + (336 hours on natural gas) = 8,363 hours/year.

[195] PDOC, p. 28.

[196] (8,760 hours/year) – (8,363 hours/year total operation of HRSG) = 397 hours/year.

[197] (397 hours/year idle) / (2 shutdowns/year) = 198.5 hours/event;
(198.5 hours/event) / (24 hours/day) = 8.27 days idle.

[198] PDOC, Appx. A, p. A-58, Conditions 40 and 41 for Unit S-7616-26-0.

[199] PDOC, Appx. A, p. A-56, Condition 29 for Unit S-7616-26-0.

[200] PDOC, Appx. A, p. A-61, Conditions 64 and 65 for Unit S-7616-26-0.

rates of pollutants from HRSG and coal dryer are not proportional for all operating scenarios but depend on the respective operating scenario. Thus, unless the PDOC includes enforceable permit conditions including monitoring for each pollutant, it must calculate the units' PTE for each based on the maximum or worst-case scenario.

The following table summarizes several operating scenarios that would be possible under the PDOC's permit conditions which would result in increased PM10, PM2.5, SO_2 and NH_3 emissions without increasing NOx or CO emissions. Because only NOx and CO emissions are required to be monitored directly via CEMS, these emission increases would not be detected.

Table 1: Combined PTE for HRSG and coal dryer under various operating scenarios

Variables	**PDOC**	**2 SU/SD, reduced downtime, no malfunctions**	**2 SU/SD, increased downtime, fewer malfunctions**	**1 SU/SD, increased downtime, no malfunctions**
Normal operation	8,000 hours/year	8,390 hours/year	8,155 hours/year	8,435 hours/year
Startup/shutdown events	2/year	2/year	2/year	1/year
Downtime	198.5 hours/event	171.5 hours/event	358 hours/event	312 hours/event
Fired on natural gas (other than during startup/shutdown)	336 hours/year	0 hours/year	100 hours/year	0 hours/year
Pollutant (tons/year)				
NOx	123.5	123.5	123.5	123.5
CO	101.7	101.5	101.5	95.9
VOC	17.5	17.3	17.3	17.2
PM10/PM2.5	59.6	**59.8**	**59.7**	**60.0**
SO_2	19.9	**20.0**	**20.0**	**20.1**
NH_3	88.9	**90.4**	**90.0**	**90.9**

Year = 12-month rolling average; SU/SD = startup/shutdown
Emissions were calculated based on the stated operating variables and otherwise relying on the Applicant's assumptions including emission factors

All these, and other, scenarios are realistic and possible under the PDOC's proposed compliance conditions. The District should determine maximum emissions from the HRSG and coal dryer for each pollutant under any operating scenario permitted under its compliance conditions to satisfy the PTE requirements of the Clean Air Act unless the PDOC is revised to include enforceable compliance conditions that would ensure that the PTE as estimated would not be exceeded. These revisions could either be enforceable permit conditions incorporating the exact assumed operating schedule, (*i.e.*, 2 startups/shutdown events per year, 397 hours of downtime, and 336 hours of firing natural gas at 80% load other than during startup/shutdown events) or, alternatively and preferably, require continuous emissions monitoring of PM10/PM2.5, SO_2 and NH_3 rather than demonstrating compliance via calculations.

Sierra Club recommends that the District require at the very least monitoring of PM10, PM2.5 and SO_2 via CEMS.

Finally, the PDOC's compliance conditions for the HRSG and coal dryer limit the number of startups and shutdowns to two each per calendar year.[201] This condition should be revised to clarify that the limitation to two startups and two shutdowns each includes both planned and unplanned events. The same condition should be repeated in the compliance conditions for the feedstock dryer (S-7616-20-0).

V.B.3 VOC Emissions from the CO_2 Vent Are Underestimated

The PDOC calculates annual emission rates for VOC emissions from the CO_2 recovery and vent system (S-7616-24-0) of 5,672 lb/year[202] on a methane basis[203] rather than for the actual VOC contained in the vent stream, *i.e.*, methanol. While the District may write permit conditions for VOC emission limits on a methane basis for purposes of determining compliance (which it did not), it must calculate the unit's PTE in tons/year based on the molecular weight of the VOC contained in the gas stream, not normalized to methane. Because the molecular weight of methane (16.04 g/mol) is only about half that of methanol (32.04 g/mol), the PDOC's emission calculations for the CO_2 recovery and vent system underestimates the unit's PTE for VOCs by a factor of two. Based on the molecular weight of methanol and otherwise relying on the PDOC's (Applicant's) assumptions, the revised PTE for the unit is 11,358 lbs/year and 5.68 tons/year of VOC (as methanol).[204] Hourly emission rates for methanol from the CO_2 vent and recovery system are equally underestimated; revised estimates are 22.5 lbs/hour of VOCs (as methanol).[205] (For a discussion of methanol as a HAP, *see* Comment VII.D.2) Because the PDOC's compliance condition for the CO_2 vent do not specify on which basis VOC emissions must be quantified[206] and the Applicant would presumably rely on the text of the PDOC and determine VOC normalized to a methane basis, this discrepancy in actual emissions and the calculated PTE would likely never be detected.

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[201] PDOC, Appx. A, Condition 41, p. A-58.

[202] PDOC, p. 93.

[203] PDOC, p. 54.

[204] 5,672 lbs/year) × (32.04/16.04) = 11,358 lbs/year;
(11,358 lbs/year) / (2,000 lbs/ton) = 5.68 tons/year.

[205] (17,584 lb-mol/hour) × (40 ppm methanol) × (32.04 lb/lb-mol) = 22.5 lbs/hour.

[206] *See* PDOC, Appx. A, Conditions for CO_2 Recovery and Vent System, pp. A-42-A-45.

V.B.4 Emission Estimates for the Auxiliary Boiler Improperly Exclude Startup and Shutdown Emissions

The Project would include a natural gas-fired auxiliary boiler (S-7616-25-0) that will provide steam for pre-startup equipment warm-up and for other miscellaneous purposes when steam from the Gasification Block or HRSG is not available.[207] The PDOC calculates emissions from the auxiliary boiler assuming a NOx concentration of 5 ppmvd.[208] The PDOC exempts startup and shutdown periods for the auxiliary boiler from compliance with this, and other, emission limits.[209] However, during a cold startup before the SCR system is fully operational, uncontrolled or partially controlled NOx emissions from the auxiliary boiler will be much higher than during normal operations). The PDOC's ambient air quality modeling and health risk assessment are also based on normal operations of the boiler without accounting for periods when the SCR system is not fully functional.[210] Thus, short-term modeled ambient concentrations do not reflect startup and shutdown emissions from the auxiliary boiler and may be considerably higher than presented in the PDOC. The District must require that emissions from the auxiliary boiler during startup and shutdown periods comply with the emission limits established in Condition 16 or provide a revised PTE and updated ambient air quality modeling that accounts for higher short-term emissions from the unit during startup and shutdown.

Further, the auxiliary boiler (S-7616-25-0) will have a design capacity of 230 MMBtu/hour and the PDOC restricts the maximum allowable heat input to 213 MMBtu/hour.[211] While the PDOC requires installation of a non-resettable, totalizing, continuously recording, mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit, it does not contain an enforceable permit condition limiting heat input on an hourly basis to ensure that the boiler would not operate in excess of the 213 MMBtu/hour limit. Because short-term emissions from the auxiliary boiler were modeled based on 213 MMBtu/hour, the PDOC must include an enforceable condition to ensure that the unit is not operated in excess of this limit and to demonstrate compliance with Condition 17. Otherwise, the PDOC's emission calculations and ambient air quality modeling for the unit must be based on the maximum auxiliary boiler design capacity of 230 MMBtu/hour. Further, the PDOC should require in a permit condition that both annual and hourly records for the unit be submitted annually to the District for review.

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[207] PDOC, p. 14.

[208] PDOC, p. 55.

[209] PDOC, Appx. A, p. A-47, Condition 16.

[210] PDOC, Appx. K, pp. 18, 42, and 56.

[211] PDOC, p. 32, p. 55, and Appx. A, p. A-47, Condition 16.

V.B.5 Fugitive Emissions from Methanol Storage Tank Are Not Accounted For

The HECA Project would operate a Rectisol-based acid gas removal ("AGR") unit to selectively separate sulfur compounds and CO_2 from the shifted sour syngas. The Rectisol absorber would use chilled methanol as a physical solvent.[212] To supply makeup methanol to the AGR unit, the Project would need a methanol storage tank. In the proceedings before the CEC, the Applicant indicated that the methanol tank would have a capacity of 300,000 gallons and an annual turnover of 1.32 and would be equipped with a vent scrubber.[213] The PDOC is silent as to the construction, dimensions, capacity, or throughput of a methanol tank or the type and control efficiency of any control equipment that would be installed; in fact, neither the methanol tank nor the associated vent scrubber is even mentioned in the document. Neither the PDOC nor the Application account for methanol emissions from the methanol storage tank. Methanol is a VOC as well as a HAP and emissions from the methanol storage tank must be included in the facility's PTE.

Emissions from storage tanks consist of working losses and breathing losses (often referred to as standing losses) as well as roof landing losses for those tanks with internal floating roofs.[214] In the proceedings before the CEC, the Applicant stated that it determined uncontrolled working and breathing losses from a fixed-roof methanol tank with EPA's TANKS model and indicates that it assumed that 33,000 gallons per month would be pumped into the methanol tank (396,000 gallons/year equivalent to a turnover of 1.32).[215] The model runs and other input assumptions (tank dimensions, average liquid height, color, etc.) are not provided[216] and could therefore not be reviewed.

Methanol tanks are typically constructed as internal floating roof tanks. An internal floating roof tank has both a permanent fixed roof and a floating roof inside. In floating roof tanks, the roof floats on the surface of the liquid inside the tank and reduces evaporative losses during normal operation. These tanks therefore have a considerably better control than simple fixed roof tanks, which, according to EPA, are

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212 PDOC, p. 10.

213 AFC, Table 2-15, p. 2-88 and HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

214 *See* EPA, AP-42, Section 7.1: Organic Liquid Storage Tanks; November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

215 *See* 1/30/2012 HECA Updated Emissions Data, "Methanol and Diesel Tanks," p. 24 of 25, pdf 145.

216 *Ibid*.

the "minimum acceptable equipment for storing organic liquids."[217] The Applicant indicates that the TANKS model run, which it claims was based on a fixed roof tank, resulted in uncontrolled working losses of 80.8 lbs/month methanol and uncontrolled breathing losses of 1,277.7 lbs/month methanol. These results indicated that the Applicant indeed assumed an internal floating roof, as a fixed roof tank would have resulted in considerably higher uncontrolled emissions.

When an internal floating roof tank is emptied to the point that the roof lands, there is a period where the roof is not floating and other mechanisms must be used to estimate emissions. These emissions continue until the tank is refilled to a sufficient level to again float the roof.[218] In response to a data request by Sierra Club in the proceeding before the CEC, the Applicant declined to estimate roof landing losses stating that "[r]oof landing losses apply only to floating roof tanks, whereas all the tanks at the site have fixed roofs, so this does not apply."[219] As stated before, all internal floating roof tanks also have a fixed roof and the Applicant's estimates indicate that it used an internal floating roof tank. If not, the model runs must be revised as a fixed roof tank cannot be permitted as BACT in the District. If an internal floating roof tank is used, roof landing losses must be included.

The Applicant then calculates a minuscule amount of controlled methanol emissions of 3.72 lbs/year from the Project's methanol tank, assuming that the tank vent scrubber has a control efficiency of 99.977.[220] This extraordinarily high vent scrubber efficiency was calculated assuming a pre-scrubber methanol concentration of 17.76% and a post-scrubber methanol concentration of 40 ppm which was "provided by Fluor."[221] None of these assumptions, including the calculated scrubber control efficiency, is supported by any documentation or vendor guarantee or incorporated into the PDOC by enforceable compliance conditions. These calculations simply rest on unsupported assumptions.

The District must review the Applicant's assumptions and issue a revised PDOC that contains a proper description of the methanol tank and its associated control equipment, estimate methanol emissions based on properly supported assumptions, and include enforceable permit conditions to assure compliance with calculated

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217 EPA, AP-42, Section 7.1: Organic Liquid Storage Tanks; November 2006; http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf.

218 *Ibid*.

219 HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

220 *Ibid* and 1/30/2012 HECA Updated Emissions Data, "Methanol and Diesel Tanks,"p. 24 of 25, pdf 145.

221 (1)-(40/1,000,000 post-scrubber)/(17.76% pre-scrubber) = 99.977%.

emission limits including tank throughput monitoring, monitoring of the methanol vapor flow rate to the scrubber, scrubber performance tests, inspections, etc. (For example, the construction permit for the Tenaska Energy Center includes six pages of permit conditions for the proposed methanol storage tank alone.[222])

V.B.6 Fugitive Emissions from Diesel Stored with Emergency Generator and Diesel Fire Pump Are Not Accounted For

The Project would have two diesel-powered emergency generators (S-7616-38-0, S-7616-39-0) and one diesel-powered firewater pump (S-7616-40-0).[223] The Applicant states that diesel fuel would be stored as an integral part of the skids.[224] As with the methanol storage tank, the PDOC does not include fugitive emissions from these internal tanks in the calculation of the Project's PTE.

V.B.7 Fugitive Equipment Leaks Are Not Adequately Supported and Are Underestimated

Equipment leaks are emissions from piping components and associated equipment including valves, connectors, pumps, compressors, process drain, and open-ended lines, as opposed to large point sources of emissions coming from stacks. These components leak small amounts of the gases and liquids they handle through seals and screw fittings. Thus, they are commonly called fugitive emissions or fugitive leaks. These emissions include compounds found in the streams that pass through the components – CO, VOCs, H_2S, total reduced sulfur ("TRS"), methane, CO_2, and numerous individual HAPs, such as methanol, and COS. The collective leaks from these fugitive components can add up to a large amount of emissions in the aggregate because there are thousands of them.

a) TOC Weight Fraction in Process Streams Is Not Supported

The PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based the average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit (process streams #1 methanol, #2 syngas, #3 shifted syngas, #5 propylene, #6 sour water, #7 H_2S-laden methanol, #8 CO_2-laden methanol, #9 acid gas, #10 ammonia-laden gas, #11 sulfur,

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[222] Illinois Environmental Protection Agency, Construction Permit – PSD Approval, Christian County Generation, LLC, Location: Taylorville Energy Center, Application No. 05040027, ID No. 021060ACB, April 30, 2012, pp. 99-104; http://yosemite.epa.gov/r5/in_permt.nsf/93a421690cb50df18625762300769ee3/eb1614a58f87ae9686257b640049b94f/$FILE/ATTM5GSQ/05040027.pdf .

[223] PDOC, Appx. A, pp. A-133-A-144.

[224] HECA Response to Sierra Club Data Request No. 76, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

#12 SRU tail gas) and the fertilizer complex (process streams #13 through #21).[225] The respective weight fractions have no support in the record as to how they were derived, what their expected variability is, and how reliable these numbers are, but are merely presented as fact.

Review of these TOC weight fractions show that even minor variability in some process areas would turn the HECA Project into a major source of hazardous air pollutants. For example, for the gasification unit, the Applicant assumed a methanol weight fraction of 79.0583% in process stream #7, the H_2S laden methanol stream, and 72.3853% in process stream #8, the CO_2-laden methanol stream. Increasing the methanol weight fractions in these process streams by less than 3% each (to 82% and 75%, respectively, and assuming a correspondingly lower CO_2 content), and otherwise relying on the Applicant's assumptions, would result in an increase of controlled fugitive methanol emissions from equipment leaks – and thus the facility's PTE for VOCs – by 0.18 tons/year.[226] In addition to increasing the PTE for VOCs, this increase is sufficient to increase total Project emissions of methanol from 9.83 tons/year to 10.01 tons/year, *i.e.*, over the 10 tons/year major HAP threshold for individual HAPs. (*See* also Comment VII.D.2).

This calculation illustrates how important the accuracy of the Applicant's assumptions is. The very precise weight percentages (six significant digits) of pollutants in various process streams relied upon by the Applicant are at odds with the general lack of experience with the equipment and layout of the project and the ever shifting information presented elsewhere.

b) SOCMI Emission Factors Are Not Applicable

The PDOC states that potential fugitive VOC emissions from piping components were estimated using emission factors from EPA's 1995 *Protocol for Equipment Leak Emission Estimates*.[227] This guidance provides separate sets of emission factors for equipment components for various industries including refineries and the synthetic organic chemical manufacturing industry ("SOCMI"). Here, the PDOC relies on SOCMI emission factors to calculate fugitive emissions for the gasification complex as well as the manufacturing complex, rather than the considerably higher emission factors developed for refineries. Yet, the PDOC provides no discussion of or demonstration that SOCMI emission factors are, in fact, applicable to the HECA Project but instead appears to rely on the following unsupported statement by the Applicant:

[225] 1/10/2013 HECA Updated Emissions Data, *see* note above table "Area Speciation" in "Fugitive Emissions – Gasification Unit," p. 19 of 25, pdf 140.

[226] Our calculations are based on formulas found in HECA's emissions spreadsheets. These spreadsheets were designated as confidential and provided to Sierra Club only after Sierra Club signed a nondisclosure agreement.

[227] PDOC, p. 36.

According to the USEPA document (USEPA, 1995a), the criteria for determining the appropriateness of emission factors are based on the following: (1) process design; (2) process operation parameters; (3) types of equipment used; and (4) types of material handled. Based on these criteria, the Project processes are most similar to a SOCMI plant. Therefore, the SOCMI fugitive emission factors from USEPA are used in the fugitive emission calculations.[228]

The Applicant provides no further demonstration which process designs, process operation parameters, types of equipment used, and types of material handled at the HECA Project are "most similar" to a SOCMI plant or provides any evidence that the physical and chemical composition of IGCC process streams is similar to that of process streams in the synthetic organic chemical industry. A coal gasification facility such as the HECA Project is not a SOCMI facility; in fact, it appears that a gasification facility has a lot in common with a refinery: Both refineries and gasification plants, for example, convert fossil fuels (petroleum, coal) into end products used to generate fuels (gas, gasoline) under similar conditions of pressure and temperature. They both also use many of the same unit processes, including sour water stripping, sulfur recovery, tail gas treating, sulfur tanks and loading, thermal oxidizers, and acid gas removal systems. Finally, a gasification facility does not manufacture "synthetic organic chemicals."

The amount of total organic compound ("TOC") emissions from equipment leaks depends on the chemicals being processed for many reasons. Process streams with different chemical (*e.g.*, polarity) and physical properties (*e.g.*, temperature, pressure) will produce different TOC emission factors, *i.e.*, the escaping tendency of chemicals inside processing units depends upon the composition of the contained material. The synthetic organic chemical industry is largely characterized by smaller equipment and more batch processes that lend themselves more readily to improved control than the processes that would be used at the HECA Project. An IGCC plant uses larger equipment operating continuously at higher temperatures. In its applicable AP-42 guidance section, EPA voiced concerns regarding potential fugitive leaks emissions from gasifiers and associated equipment stating that "leaks may be more severe from pressurized gasifiers and/or gasifiers operating at high temperatures."[229]

The SOCMI factors were developed by EPA based on field measurements at 30 individual chemical process units representing a cross-section of the synthetic organic chemicals industry and screening and bagging data were obtained from

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[228] Application, p. 5-12.

[229] EPA, AP-42, Section 11.11 Coal Conversion; http://www.epa.gov/ttnchie1/ap42/ch11/final/c11s11.pdf.

19 ethylene oxide and butadiene producers.[230] Regarding the applicability of these emission factors to other industries, EPA concludes "in most cases, SOCMI emission factors and correlations are applicable for estimating equipment leak emissions from the polymer and resin manufacturing industry. This is because, in general, these two industries have comparable process design and comparable process operation, they use the same types of equipment, and they tend to use similar feedstock."[231] The polymer and resin manufacturing industry, which manufactures plastics, glues, fiberglass backing material, fiber optics components, and other physical materials, is not similar to coal gasification in terms of types of equipment or feedstocks used. Further, SOCMI emission factors were developed for processes used to generate synthetic organic chemicals such as acetaldehyde, acetone, and phenol,[232] not for processes used to generate syngas and its byproducts, *e.g.*, air separation, raw syngas production, syngas conditioning, acid gas removal, sulfur recovery, methanation, and dehydration.

Coal gasification facilities are not chemical plants, which have had to keep tighter leak standards far longer than other industries as a practical matter due to the extremely hazardous nature and high value of the chemicals they handle. First, SOCMI facilities handle materials of greater value than those at an IGCC facility, providing an incentive to minimize equipment leaks. Second, a SOCMI facility typically handles highly volatile, toxic and hazardous substances, which must be minimized to prevent worker exposure. These conditions dictate design and operating practices at these facilities to minimize releases. The PDOC contains no evidence of similar concerns at the HECA Project. In fact, it fails to even consider the use of leakless and low-leak technology as BACT. (*See* Comment VI.H). These equipment components would routinely be used in the synthetic organic chemical industry to preserve feedstock and protect workers. These differences would result in lower emissions at a SOCMI facility than at a gasification facility such as the HECA Project without similar concerns. Most processing units in IGCC facilities operate at higher temperature and pressures than typical SOCMI processes, resulting in higher component failures and thus higher leaks. In short, the emission factors developed for SOCMI facilities are not relevant to the gasification of coal and production of syngas and underestimate fugitive emissions from the HECA Project.

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[230] EPA, Protocol for Equipment Leak Emission Estimates, Report EPA-453/R-95-017, November 1995, Sections 2.2.2 and 2.3.1 and Table 2-1 (hereafter "Protocol for Equipment Leak Emission Estimates"); www.epa.gov/ttnchie1/efdocs/equiplks.pdf; and EPA, Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs, Report EPA-450/3-82-010, April 1982 (hereafter "EPA 4/82"), Section 2.1.6 and Table 2-12; http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009YVL.txt.

[231] Protocol for Equipment Leak Emission Estimates, p. 2-6.

[232] *See* EPA 4/82, Table 2-12.

V.B.8 Emissions Associated with Fluxant Delivery, Storage, and Handling Are Not Accounted For

As discussed above, the PDOC does not include emissions associated with the delivery, storage and handling of the approximately 175 tons/day and 59,000 tons/year of limestone fluxant and the 10% increase in emissions resulting from the additional 88 tons/day of gasification solids that are generated by using fluxant. The District must also develop adequate compliance conditions restricting the quantity of daily and annual fluxant use and number of deliveries.

V.B.9 On Site Fugitive Dust Emissions from Paved Roads and Wind Erosion Are Not Accounted For

HECA did not take into account fugitive emissions to determine its potential to emit and major source status as required by the Clean Air Act and local rules. Sources that fall in one of the 28 named industrial source categories must take into consideration fugitive emissions, *i.e.*, emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening" when determining whether emissions reach the 100 ton/year emissions threshold to determine major source status.[233] The HECA Project falls within the source category "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input" and must therefore account for fugitive emissions when determining potential to emit and major source status.[234] The PDOC's determination of potential to emit and major source status for purposes of PSD does not account for particulate matter emissions associated with fugitive entrained road dust generated by on-site vehicle movement nor for particulate matter emissions from wind erosion.[235] On-site fugitive dust emissions can be substantial and must be included in the PTE and the PSD major source determination for PM, PM10, and PM2.5.

a) Paved Roads

HECA estimated fugitive dust PM10 and PM2.5 emissions from onsite paved roads in in its Application (and provided substantially revised estimates in its 1/10/2013 HECA Updated Emissions Data),[236] yet, these estimates were not incorporated into the PDOC's PTE. Sierra Club finds that the paved road PM10 and PM2.5 emissions calculated by HECA use incorrect inputs and result in substantially

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[233] 40 CFR §§ 52.21(b)(1)(iii), (b)(1)(c)(iii); *see* SJAPCD Rule 2410 (incorporating 40 CFR Part 52.21 into the SIP).

[234] 40 CFR § 52.21(b)(1)(i)(c)(iii)(z).

[235] *Compare* PDOC, table "Post-Project Stationary Source Potential to Emit [SPPE2] (lb/year)", p. 93, and table "PSD Major Source Determination: Potential to Emit (tons/year)", p. 96.

[236] 1/10/2013 HECA Updated Emissions Data, "Fugitive Dust on Paved Road," p. 16 of 17, pdf 120.

underestimated emission rates. Sierra Club previously commented on PM10 emissions from paved roads[237] and revises and expands its comments as follows:

HECA used an equation obtained from EPA's AP-42, Section 13.2.1, for paved roads to calculate particulate matter (fugitive dust) emissions from onsite vehicle traffic.[238] This equation is as follows:

$E_{ext} = [k(sL)^{0.91} \times (W)^{1.02}] \times [1-P/4N]$

where: E_{ext} = emission factor in the same units as k

k = particle size multiplier; 0.25 g/vehicle mile traveled (VMT) for PM2.5; 1.0 g/VMT for PM10.[239]

sL = road surface silt loading (g/m^2)

W = average weight of vehicles (tons)

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

N = number of days in the averaging period (*e.g.*, 365 for annual, 91 for seasonal, 30 for monthly).

The values used for any of the variables in the above equation, k, sL, W, P, and N, will have an impact on the final result, *i.e.*, the calculated particulate matter emission rates. Our review of HECA's paved road fugitive dust PM10 and PM2.5 emission calculations finds that the key inputs to this equation are greatly underestimated.

- The PM10 and PM2.5 emission calculations use an inappropriate value for silt loading for onsite vehicle travel on paved roads.

- The 24-hour PM10 and PM2.5 emissions from paved roads inappropriately included a rainfall correction.

- The PM10 and PM2.5 emission calculations use inappropriate vehicle weights for trucks traveling onsite.

Each of these inputs, including the necessary corrections to the emission rate calculations are discussed below.

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[237] Andrea Issod, Sierra Club, Letter to Dave Warner, SJVAPCD, and Robert Worl, CEC, Re: Preliminary PM Modeling Comments on the PDOC for the HECA Project (08-AFC-08A), April 26, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-26_Sierra_Club_Comments_on_PDOC_TN-70503.pdf.

[238] *Ibid.*

[239] *Ibid.*

Silt Loading

Fugitive dust emissions from paved roads have been found to vary with the "silt loading" present on the road surface, which is the amount of particulate matter per paved surface area. Here, the Applicant assumed a silt loading value of 0.031 grams per square meter ("g/m^2"), which is the default value from URBEMIS 9.2 (URBan EMISsions Model) for Kern County.[240] This value is entirely inappropriate for determining fugitive entrained road dust emissions for the HECA Project site for a number of reasons and substantially underestimates particulate matter emissions.

First, the default silt loading value for Kern County from URBEMIS was developed to represent vehicle travel on all types of public roads including freeways, arterials, collector, local and rural roads throughout the county. As such it is appropriate for vehicle travel on public roads throughout the county, not for onsite roads at an industrial site whose silt loading is largely attributable to dust generated by material handling on site, including truck loading and unloading. EPA has developed silt loading values for industrial sites, which are included in the same AP-42 guidance the Applicant relied upon for the equation, *i.e.*, Section 13.2.1 *Paved Roads*. Table 13.2.1-3, *Typical Silt Content and Loading Values for Paved Roads at Industrial Facilities*, in this document tabulates ranges and mean silt loading values measured for eight different industries at 19 sites. The measured silt loading values at these industries range from 0.05 g/m^2 measured at a corn wet mill to 400 g/m^2 at a copper smelting facility with mean values ranging from 1.1 to 292 g/m^2.[241] Thus, HECA assumes a silt loading value that is lower than any of the values measured at other industrial facilities. Sierra Club requested that the Applicant provide emission estimates from on-site paved roads based on an appropriate silt loading value for paved roads at industrial facilities. The Applicant declined claiming that "…the AP-42 table referenced for paved roads at industrial facilities (Table 13.2.1-3) is not applicable to the HECA Project. The listed facility types are extremely different from the HECA Project (*e.g.*, copper smelting, sand and gravel processing) and would significantly overestimate silt loading." The Applicant does not provide any reasonable explanation for using a silt loading value for public paved roads instead.[242] Such lack of a reasonable explanation lead EPA recently

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240 *Ibid*.

241 EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p. 13.2.1.10.

242 The Applicant falsely claims that Sierra Club endorsed the default silt loading value for Kern County by taking the following statement in Sierra Club Data Request 27 out of context: "The silt loading default value used in URBEMIS 9.2 applies only to operational traffic associated with a project…" This data request addressed HECA's estimates of entrained road dust emissions during the construction phase of the Project pointing out that the default factor in URBEMIS is provided for estimating fugitive dust emissions resulting from vehicle movement on public paved roads during the operational phase of a project and is not appropriate for estimating paved road dust emissions during construction of the HECA

to object to a permit for the Cash Creek Generation Project, specifically because the permit record lacked a reasonable demonstration that the assumed silt loading value assumed for the project site of 0.4 g/m^2 was appropriate.[243]

Second, to the extent that onsite silt loading is affected by dust tracked-in from roads leading to the Project site, the roads surrounding the HECA site are rural roads surrounding agricultural land and as such have much higher silt loading values than the assumed default value. CARB developed a table of silt loading values for various types of roads in California ranging from freeways to rural areas. The CARB-reported silt loading values are averages of silt loadings measured by Midwest Research Institute in the South Coast Air Quality Management District and the San Joaquin Valley Unified Air Quality Management District.[244] These silt loading values were used by CARB for the District' 2003 PM10 State Implementation Plan.[245] For rural roads, such as those surrounding the Project site, CARB derived a silt loading value of 1.6 g/m^2, which is over 50 times higher than the value used by the Applicant.[246]

Third, the default silt loading value for Kern County from URBEMIS already accounts for the county-specific rainfall correction, which the Applicant then erroneously applies again.[247] (More on rainfall correction below.)

Finally, AP-42 highly recommends the collection and use of site-specific silt loading data.[248] Where a source cannot obtain site-specific data, AP-42 recommends the selection of an appropriate *mean* value from the table listing silt loadings for industrial roads.[249] However, use of a mean value reduces the quality rating, *i.e.*, the confidence in the emission estimates, by two levels.[250]

Project. At no point did Sierra Club suggest that the default silt loading value in URBEMIS for public roads is appropriate for calculating on-site emissions from HECA's industrial project site.

243 EPA, In the Matter of Cash Creek Generation, LLC, Henderson County, Kentucky, Title V/PSD Air Quality Permit No. V-09-006, Issued by the Kentucky Division for Air Quality, Order Granting in Part and Denying in Part Petition for Objection to Permit, Petition No. IV-2010-4, June 22, 2012, pp. 27-28.

244 CARB, Emission Inventory, Section 7.8 – SJV, Entrained Paved Road Dust, Paved Road Travel, June 2006; http://www.arb.ca.gov/ei/areasrc/PMSJVPavedRoadMethod2003.pdf.

245 *Ibid*.

246 This silt loading rate is not corrected for rainfall, which is appropriate for determining short-term emission rates for PM10 and PM2.5 emissions from paved roads. For estimates of annual emissions, a rainfall correction factor is appropriate.

247 *See* "P = 36 days/year Buttonwillow Station 1940-2011, WRCC" in 1/10/2013 HECA Updated Emissions Data, Fugitive Dust on Paved Road, p. 16 of 17, pdf 120.

248 EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p. 13.2.1-9.

249 *Ibid.*

250 *Ibid.*

Correcting for the underestimated silt loading value has a profound effect on emission estimates for fugitive road dust. For example, instead of using the default value for silt loading of public paved roads in Kern County of 0.031 g/m^2, using the lowest mean value reported in AP-42 for any of the investigated industries of 1.1 g/m^2 (corn wet mills) increases emission estimates by a factor of about 26[251]; using the highest mean value determined for any industry of 292 g/m^2 (copper smelting operations) increases emission estimates by a factor of about 4,134.[252] The PDOC must provide a reasoned explanation which silt loading value it will choose to estimate fugitive dust emissions from HECA and include enforceable compliance conditions that will ensure that the calculated PTE for the facility is not exceeded. Permits for other industrial facilities including gasification plants frequently require measurement of on-site silt loading to demonstrate compliance. For example, the PSD permit issued for the Power Holdings of Illinois gasification facility includes extensive permit conditions for such measurements[253] as does the PSD permit for the Taylorville Energy Center gasification facility.[254]

Rainfall Correction

Sierra Club notes that the equation provided by AP-42 incorporates a rainfall correction factor under the simplifying assumption that annual (or other long-term) average emissions are inversely proportional to the frequency of measurable precipitation by application of a precipitation correction term.[255] Inclusion of this rainfall correction factor is only warranted for annual average emissions, not for short-term emissions. The Applicant incorrectly estimates short-term PM10 and PM2.5 emissions from paved roads using a yearly total of 36 rain days per year (in addition to incorrectly using the rainfall correction on an already rainfall-corrected silt loading

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[251] $(1.1)^{0.91}/(0.031)^{0.91} = 25.74$.

[252] $(292)^{0.91}/(0.031)^{0.91} = 4{,}133.89$.

[253] *See* Condition 4.8.8 ("…shall conduct measurements of the silt loading on various affected roadway segments and parking areas as follows… using the "Procedures for Sampling Surface/Bulk Dust Loading," Appendix C.1 in Compilation of Air Pollutant Emission Factors, USEPA, AP-42. A series of samples shall be taken to determine the average silt loading and address the change in silt loadings as related to the amount and nature of vehicle traffic and implementation of the operating program.") in Illinois Environmental Protection Agency, Construction Permit – PSD Approval, NSPS Emission Units, Power Holdings of Illinois, LLC, Application No. 07100063, ID No. 081801AAF, October 26, 2009; http://www.epa.state.il.us/public-notices/2009/power-holdings/final-permit.pdf.

[254254] *See* Condition 4.11.8 in Illinois Environmental Protection Agency, Construction Permit – PSD Approval, Christian County Generation, LLC, Location: Taylorville Energy Center, Application No. 05040027, ID No. 021060ACB, April 30, 2012; http://yosemite.epa.gov/r5/in_permt.nsf/93a421690cb50df18625762300769ee3/eb1614a58f87ae9686257b640049b94f/$FILE/ATTM5GSQ/05040027.pdf.

[255] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-5.

value). This underestimates maximum daily emissions because there are many days in Kern County when there is no rainfall.

Truck Weight

Vehicle weights are the other component of the AP-42 emission factor for calculating PM10 and PM2.5 emission rates from paved roads. It is the average vehicle weight that is used for the emission calculation (usually the average of loaded and unloaded truck weights).[256] The Applicant's emission estimates are incorrect.

First, the Applicant's paved road PM10 and PM2.5 emission calculations incorrectly calculate emissions separately for each type of vehicle on site, *e.g.,* operation and maintenance vehicles with an average weight of 3 tons and for large trucks with an average weight of 17.5 tons. This approach is incorrect because the equation calls for a fleet-average weight and should not be used for separate weight classes. EPA in its AP-42 guidance notes that the equation "calls for the *average weight of all vehicles traveling the road*. For example, if 99 percent of traffic on the road are 2 ton cars/trucks while the remaining 1 percent consists of 20 ton trucks, then the mean weight "W" is 2.2 tons. More specifically, [the equation] is not intended to be used to calculate a separate emission factor for each vehicle weight class. Instead, *only one emission factor should be calculated to represent the "fleet" average weight* of all vehicles traveling the road.[257]

Second, the Applicant assumed an empty truck weight for large haul trucks of five tons and a full truck weight equaling 30 tons.[258] This results in an average truck weight of 17.5 tons and means that these trucks are hauling 25 tons of material. An empty product truck weight of five tons, however, is not realistic – a five ton truck is not an appropriate size for hauling 25 tons of material. For most product-handling facilities, emission calculations are based on an empty truck weight of at least 15 tons. For example, the Taylorville Energy Project estimated paved road emissions on empty truck weights of 25 tons for hauling slag, 15 tons for hauling liquid sulfur and 15 tons for methanol deliveries.[259] The EPA, in developing AP-42 Section 13.2.1, identifies an average vehicle weight of 35 tons for heavy duty diesel trucks.[260] A 20-ton truck (empty)

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[256] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-4.

[257] EPA, AP-42 Section 13.2.1, Paved Roads, January 2011, p.13.2.1-4, *emphasis* added; http://www.epa.gov/ttnchie1/ap42/ch13/final/c13s0201.pdf.

[258] 1/10/2013 HECA Updated Emissions Data, "Fugitive Dust on Paved Road," p. 16 of 17, pdf 120.

[259] Taylorville Energy Center, Table C-21: Haul Road Potential Emission Calculations, p. C-68.

[260] EPA, Emission Factor Documentation for AP-42, Section 13.2.1, January 2011, p. 4-37; http://www.epa.gov/ttn/chief/ap42/ch13/bgdocs/b13s0201.pdf.

hauling 25 tons of material has an average vehicle weight of 32.5 tons.[261] Correcting the average product truck weight from 17.5 tons to 32.5 tons (and for the moment ignoring the effect of the few operation and maintenance vehicles on the average on-site vehicle weight) will increase emissions by a factor of 1.88.[262] The District should obtain from the Applicant the vehicle count and empty and loaded vehicle weights for each of the vehicles that would operate on site (operation and maintenance vehicles, haul trucks for coal, petcoke, limestone fluxant, fertilizer product, sulfur product, gasification solids, methanol, etc.) to determine a correct fleet-average weight for purposes of estimating fugitive dust emissions from paved roads. Because the PDOC permits delivery of coal via both rail and truck[263] and contains no compliance conditions other than daily throughput at truck unloading and transfer system, the District should base its PTE calculations for fugitive dust from paved roads on a worst-case scenario, *i.e.*, deliveries of all fuels via truck.

Summary

The PDOC must be revised to include fugitive dust emissions from on-site paved roads in the PTE and ambient air quality modeling taking into account the above discussed errors and incorporate appropriate silt loading and vehicle weight modifications. Emission factors determined for purposes of modeling short-term PM10 and PM2.5 emissions may not include the rainfall correction factor.

Further, the PDOC does not currently provide a description of any of the onsite roads or any requirement that roads at the Project site would be paved. The PDOC should include such a detailed description of all roads on site and require that they are paved. If there are any unpaved roads on site, the emission estimates must be calculated based on EPA's guidance for unpaved roads.[264] The PDOC's compliance conditions addressing fugitive dust from paved and unpaved roads must be amended to ensure compliance with the estimated emissions, *e.g.,* requiring measurement of silt loading as required in permits for other gasification facilities.

b) Wind Erosion

The PDOC fails to account for particulate matter emissions due to wind-blown dust from roadways, parking areas, and access areas at the facility site in its PTE

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[261] (20 tons + 45 tons)/2 = 32.5 tons.

[262] $(32.5)^{1.02}/(17.5)^{1.02} = 1.88$.

[263] PDOC, p. 7.

[264] EPA, AP-42, Section 13.2.2, Unpaved Roads, November 2006; http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s0202.pdf.

calculations. These emissions can be calculated with EPA's AP-42, Section 13.2.5, *Industrial Wind Erosion*.[265]

V.C Lack of Enforceable Compliance Conditions

In addition to the above discussed problems with the PDOC's enforceability, there are several other areas that lack enforceable compliance conditions to ensure compliance with the PTE and emission limits as determined by the District.

V.C.1 Lack of Fuel/Feedstock Specifications

Many of the emission estimates relied upon by the PDOC to determine the PTE for the HECA Project are based on assumptions about the origin of the coal and petcoke as well as the ratio of these fuels in the feedstock blend that would be gasified at the facility. For example, the emission factors for NOx, CO, VOC, particulate matter, and SO_2 used to determine emissions from the power block are based on the highest emission factors for each pollutant from six operating scenarios (at various ambient temperatures and on peak/off peak) using a feedstock blend with 75% calorific input from "Lee Ranch Coal" and 25% calorific input of "Carson High Sulfur Coke." These emission factors were provided by MHI specifically for the MHI 501GAC CTG operating on this feedstock blend[266] and were presumably determined at MHI's Nakoso facility. Similarly, the Applicant's calculations of mercury emissions rely on the assumption that the Project would gasify coal from Peabody's El Segundo mine with a mercury content of 0.13 parts per million by weight ("ppmw").[267] Emission factors vary with the specific characteristics of the fuel and the feedstock blend. Yet, the PDOC entirely omits any discussion of or includes compliance conditions for fuel specifications or the 75% coal/25% petcoke feedstock blend; it also does not supply a vendor guarantee for the assumed emission factors when firing a different feedstock blend or using different fuels.

The Applicant insists that it requires permission to gasify a range of feedstock blend in order to

> … maintain sufficient fuel diversity and maximize the number of potential fuel suppliers; this is necessary to minimize fuel costs and avoid curtailment caused by short-term disruptions in fuel supply that can occur in the absence of sufficient flexibility.

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[265] http://www.epa.gov/ttnchie1/ap42/ch13/final/c13s0205.pdf.

[266] 1/10/2013 HECA Updated Emissions Data, "Power Block – Emissions Summary" and "HRSG and Coal Dryer,"p. 5 of 32, pdf 38.

[267] HECA Response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Furthermore, HECA's specific Cooperative Agreement and Section 48A tax credits require that HECA use coal for at least 75 percent of the energy input for operations for the first 2 and 5 years, respectively, under each agreement. Accordingly, the Applicant would be willing to consider a target of 75 percent coal for the HECA Project's gasification feedstock (heat input basis), provided this is computed on an annual averaging basis, and there is sufficient margin to allow the HECA Project to run above the average during the first 5 years of operations to ensure meeting the minimum regulatory requirements.[268]

The Applicant also indicates that it is more likely that the HECA Project would gasify coal from Peabody's El Segundo mine rather than coal from the Lee Ranch mine, which was used to run the gasification test by MHI.[269] Coal from the Lee Ranch mine and El Segundo mine differ substantially in their composition with respect to calorific value, moisture content, ash content, sulfur content, trace element constituents, etc., as shown in the inset table below, and emission rates will vary with the coal composition. The same is true for petcoke from different suppliers.

Table 2: Coal Composition from Different Suppliers

	Lee Ranch mine*	El Segundo mine**
Moisture (as received) %	14.8	18.1
Ash (dry) %	21.3	17.9
Volatile matter (dry) %	39.2	40.8
Fixed carbon (dry) %	39.5	41.3
Btu content (dry)	10,860	11,209
Sulfur (dry) %	1.09	1.29
Sulfur lb SO_2/MMBtu	2.01	2.30
Mercury (dry whole coal) ppm	0.09	0.13

* Data are excerpted from Lee Ranch Coal, 2009 through 2013 Typical Analysis, May 11, 2009, provided by HECA in response to Sierra Club Data Request No. 38, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

** With the exception of mercury content in coal, data are excerpted from El Segundo, 5-Year Plan Typical Analysis, February 16, 2009, provided by HECA in response to Sierra Club Data Request No. 17, August 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf;

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268 HECA Response to Sierra Club Data Request No. 143.c; February 2013, http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

269 HECA Response to Sierra Club Data Request No. 17a, August 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-09-18_Applicants_Responses_to_Sierra_Club_Data_Requests_1-97_TN-66979.pdf; and HECA Response to CEC Data Request A206, January 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-01-16_Applicants_Responses_to_CEC_Data_Request_Set_Three_45-Day_Extension_TN-69172.pdf.

mercury content in coal from the El Segundo mine was provided by HECA in response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Because the PDOC requires continuous emission monitoring only for NOx and CO[270] and determines compliance with emission limits for SOx, PM10, and VOCs by calculation[271] based on source testing once every 12 months,[272] exceedance of emission limits specified in the PDOC's compliance conditions for pollutants other than CO and NOx would not be detected during times other than the scheduled source test. For mercury emissions, an exceedance would never be detected as only one initial speciated source test is required after commissioning.[273] The PDOC must be revised to either contain testing for fuel specifications and a specific fuel blend or contain enforceable compliance conditions for all pollutants, that would ensure that emissions from the power block would not exceed specified emission limits when firing different coals or feedstock blends.

V.C.2 Lack of Operating Conditions for CO_2 Vent during Mature Operation

The PDOC calculates the PTE criteria pollutant emissions from the CO_2 vent assuming a cumulative maximum duration of venting episodes of 504 hours/year for early operations, which are expected to last approximately two years, and implements this assumption in a compliance condition.[274] During mature operations, significantly fewer venting episodes are expected for a total 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity).[275] The District should consider establishing compliance conditions for mature operations of the Project which incorporate fewer hours of permissible venting per year. Any such revision must ensure that HECA may not generate ERCs attributed to the emission reductions.

V.C.3 Compliance Conditions for Cooling Tower Are Not Enforceable

The PDOC establishes BACT for PM10 emissions from the cooling towers serving the gasification block and process unit (S-7616-27-0), the air separation unit (S-7616-28-0), and the power block (S-7616-29-0) as cellular type drift eliminators with a

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270 PDOC, Appx. A, Condition 64, p. A-61.

271 PDOC, Appx. A, Condition 23, pp. A-55-A56.

272 PDOC, Appx. A, Condition 54, pp. A-60.

273 PDOC, Appx. A, Condition 53, p. A-59.

274 PDOC, Appx. A, p. A-43.

275 PDOC, Appx. I, pp. 7-8.

drift rate of 0.0005%.[276] The PDOC requires demonstration of compliance with the PM10 daily emission limits for the three cooling towers by multiplying the circulating water recirculation rate as determined by a non-resettable flow meter times the total dissolved solids ("TDS") concentration in the circulating water as determined by a quarterly cooling water sample analysis times the manufacturer's design drift rate for the drift eliminators.[277]

The performance of drift eliminators may change over time or with operating conditions. Yet, the PDOC contains no condition to demonstrate that the specified drift efficiency of 0.0005%, which is part of the above calculation for compliance demonstration, is continually met. Therefore, the PM10 emission limits are not enforceable. To demonstrate compliance with the PM10 emission limits – and limit emissions to those that were included in the air dispersion modeling – a condition must be imposed to assure that the specified drift efficiency of 0.0005% is continually met. This is normally achieved by requiring annual performance tests performed by a Cooling Technology Institute-licensed drift testing firm to assure compliance with the specification.

Further, Sierra Club recommends installing conductivity meters to quickly identify problems and keeping a log of all parameters including the calculated emission rate in lb/day to monitor trends and spot deterioration in performance.

V.C.4 *Lack of Enforceable Permit Condition for Nitric Acid Unit*

The PDOC calculates the PTE (or SPPE2) for NOx emissions from the nitric acid unit (S-7616-35-0) at 33,617 lb/year assuming the plant operates 8,052 hrs/year and includes a permit condition that establishes an annual emission limit for NOx.[278] This permit condition is not enforceable as there is no limit or monitoring proposed for the annual hours of operation of the nitric acid unit. Further, the PDOC calculates the PTE for NH_3 emissions from the nitric acid unit at 4,026 lb/year but fails to include any condition enforcing this emission estimate as a permit condition. Therefore the PTE for NOx and NH_3 emissions from the nitric acid unit are not enforceable. The PDOC must contain proper permit limits and monitoring and recordkeeping provisions to ensure compliance with both PTE estimates.

V.C.5 Lack of Enforceable PM2.5 Emission Limits

The PDOC calculates potential to emit for PM2.5 in Section VIII but fails entirely to incorporate enforceable compliance conditions for any of the Project's emissions

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[276] PDOC, Appx. C, p. C-20.

[277] PDOC, Appx. C, Conditions 13 through 19 for S-7616-27-0, S-7616-28-0, and S-7616-29-0.

[278] PDOC, p. 89, and Appx. A.

units. Therefore, the facility's calculated PTE for PM2.5 is not enforceable and fails to guarantee that a) the Project's PM2.5 emissions would remain under the major source threshold, b) sufficient offsets are provided, and c) the conclusions of the AAQI/HRA analysis are correct. The PDOC must incorporate determination of compliance conditions to enforce the PM2.5 PTE determined in Section VIII.

V.C.6 Inadequate Reporting Conditions

Rather than only requiring that the Applicant keep records for inspection upon request by the District, Sierra Club recommends that the PDOC incorporate conditions requiring annual reporting to the District for all units that are required to keep records of emission limits (at a minimum when exceedances are recorded). The District must keep this information in its records and make it available to the public for review and to ensure compliance with permit conditions. Public participation and enforcement is a fundamental part of the Clean Air Act.[279] The Clean Air Act provides for civil penalties as a remedy available for enforcement by citizen plaintiffs when the agency has failed to take action.[280]

VI. THE PDOC FAILS TO REQUIRE BEST AVAILABLE CONTROL TECHNOLOGY AND LOWEST ACHIEVABLE EMISSION RATE

The federal Clean Air Act requires that a permit issued to a major new source of air pollution include emission limits that reflect the installation of BACT for each regulated air pollutant; in a nonattainment area, the Act requires emission limits that reflect installation of LAER for each regulated pollutant.[281] Federal regulations for permitting new facilities require BACT for new sources in attainment areas, and LAER – a generally more stringent level – for new sources in nonattainment areas. In the federal regulations, LAER is defined as:

> Lowest achievable emission rate (LAER) means, for any source, the more stringent rate of emissions based on the following:
>
> (A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

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279 For example, *Pennsylvania v. Del. Valley Citizens' Council for Clean Air*, 478 U.S. 546, 560 (1986) (Congress enacted § 304 specifically to encourage "citizen participation in the enforcement of standards and regulations established under this Act," S. Rep. No. 91-1196, p. 36 (1970), and intended the section "to afford ... citizens ... very broad opportunities to participate in the effort to prevent and abate air pollution.").

280 42 U.S.C. § 7604.

281 42 U.S.C. §§ 7471, 7475(a)(2), 7479(3), 7501; 7503(a)(2); 40 C.F.R. 51.21(j)(2),40 CFR 51.165(a)(1)(xiii).

> (B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.[282]

Under the federal regulations incorporated into District Rule 2401, BACT is defined as:

> Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.[283]

LAER thus differs from BACT in that there is no consideration of economic, energy or environmental factors and the cost considerations are extremely limited.[284] Cost can only be considered to the degree that the costs are so prohibitive that the source could not be built.[285] "If some other plant in the same (or comparable) industry uses that control technology, then such use constitutes evidence that the cost to the industry of that control is not prohibitive."[286]

The District implements BACT and LAER requirements in SJVAPCD Rules 2410 and 2201. Under California state law and Rule 2201, the District is required to apply "BACT" for new sources under essentially the same requirements as federal LAER.[287] As the District explains in the PDOC, the District's BACT definition does not allow a

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[282] 40 C.F.R. 51.165(a)(1)(xiii).

[283] Rule 2401, 40 C.F.R. 52.21(b)(12).

[284] NSR Manual p. G.3.

[285] *Id*.

[286] *Id*. at p. G.4.

[287] *See*, for example, SJVAPCD, Reasonably Available Control Technology (RACT), Demonstration for Ozone State Implementation Plans (SIP), April 16, 2009; http://www.valleyair.org/Air_Quality_Plans/docs/RACTSIP-2009.pdf.

consideration of costs for control techniques that have been achieved in practice."[288] The District's Rule 2201 definition of BACT requires:

> 3.10 Best Available Control Technology (BACT): is the most stringent emission limitation or control technique of the following:
>
> 3.10.1 Achieved in practice for such category and class of source;
>
> 3.10.2 Contained in any State Implementation Plan approved by the Environmental Protection Agency for such category and class of source. A specific limitation or control technique shall not apply if the owner of the proposed emissions unit demonstrates to the satisfaction of the APCO that such a limitation or control technique is not presently achievable; or
>
> 3.10.3 Contained in an applicable federal New Source Performance Standard; or
>
> 3.10.4 Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be cost effective and technologically feasible for such class or category of sources or for a specific source.

The District's BACT requirement in Rule 2201 is thus more stringent than the BACT requirements in Rule 2410.[289] A permit cannot issue without proper BACT and LAER emission limits.[290] As discussed in the following, the PDOC's BACT analyses are flawed.

VI.A BACT and LAER Require a Thorough and Well-Documented Analysis

The following section presents the well-established requirements of the BACT analysis, most of which are applicable to the LAER analysis. Applicants must select LAER technology in a similar manner as BACT, as described above, except that there is no consideration of economic, energy, or environmental factors and cost considerations are minimal. BACT and LAER require a case-by-case analysis.[291]

By using the terms "maximum" and "achievable," the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining

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[288] PDOC, p. 143.

[289] *Id*.

[290] 42 U.S.C. §§ 7475(a)(4); 7503(a)(2); *see also Alaska Dep't of Envtl Conservation v. EPA,* 540 U.S. 461 (2004) (hereinafter "*Alaska DEC*") (upholding EPA's authority to block a PSD permit where the state permitting authority's BACT determination was unreasonable).

[291] 42 U.S.C. § 7479(3); 7503(a)(2); NSR Manual, pp. B.5, G.1-4.

BACT.[292] Pursuant to those requirements, "the most stringent technology is BACT" unless the applicant or Agency can show that such technology is not feasible or should be rejected due to specific collateral impact concerns.[293] The collateral impacts exception is a limited one, designed only to act as a "safety valve" in the event that "unusual circumstances specific to the facility make it appropriate to use less than the most effective technology."[294] If the Agency proposes permit limits that are less stringent than those for recently permitted similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected.[295] The need to aim for the lowest limits achievable as part of a BACT analysis was recently emphasized by the EAB, which stated in reversing a permit issuance:

> If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.[296]

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.[297] A proper BACT limit must account for both general improvements within the pollution control technology industry and the specific applications of advanced technology to individual sources, ensuring that limits are increasingly more stringent. BACT may not be based solely on prior permits, or even emission rates that other plants have achieved, but must be calculated based on what available control options and technologies can achieve for the

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[292] *Alaska DEC*, 540 U.S. at 485-86

[293] *Alaska Dep't of Envtl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002).

[294] *In re Kawaihae Cogeneration Project*, PSD Appeal Nos. 96-6, 96-10, 96-11, 96-14, 96-16, 7 E.A.D. 107, 117 (E.A.B. Apr. 28, 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific *local* impacts); *In re Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824, 827 (Adm'r 1989); NSR Manual at B.29.

[295] *In re Indeck-Elwood, LLC*, PSD Appeal 03-04, 13 E.A.D., slip op. at 77, 79-81 (E.A.B. Sept. 27, 2006); *In re Knauf Fiber Glass, GMBH*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 131-32 (E.A.B. Feb. 4, 1999).

[296] *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 16 (EAB 2009) (hereinafter "*In re NMU*"); see also *Utah Chapter of Sierra Club*, 226 P.3d at 734-35 (remanding permit where there "was evidence that a lower overall emission limitation was achievable").

[297] NSR Manual, p. B.12 ("[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control"); pp. B.5 ("[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams…"); and B.16 ("[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.")

project at issue and set standards accordingly.[298] For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.[299]

The BACT review "is one of the most critical elements of the PSD permitting process" because it determines the amount of pollution that a source will be allowed to emit over its lifetime.[300] As such, the BACT analysis must be "well documented" and a decision to reject a particular control option or a lower emission limit "must be adequately explained and justified."[301] While the applicant has the duty to supply a BACT analysis and supporting information in its application, "the ultimate BACT decision is made by the permit-issuing authority."[302] Therefore, the District has an independent responsibility to review and verify HECA's BACT analyses and the information upon which those analyses are based to ensure that the limits in any permit reflect the maximum degree of reduction achievable for each regulated pollutant.[303]

Information to be considered in determining the performance level representing achievable limits includes manufacturer's data, engineering estimates, and the experience of other sources.[304] The Applicant and agency must survey not only the EPA's RACT/BACT/LAER Clearinghouse ("RBLC") and their own databases, but also many other sources, both domestic and foreign, including other agencies' determinations and (draft) permits, permit applications for other proposed plants, technology vendors, performance test reports, consultants, technical journal articles, etc.

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[298] An agency must choose the lowest limit "achievable." While a state agency may reject a lower limit based on data showing the project does not have "the ability to achieve [the limit] consistently," *In re Newmont*, PSD Appeal No. 05-04, 12 E.A.D. 429, 443 (E.A.B. Dec. 21, 2005), it may only do so based on a detailed record establishing an adequate rationale, *see id.* Moreover, actual testing data from other facilities is relevant to establishing what level of control is achievable given a certain technology. *Id*. at *30. The word "achievable" does not allow a state agency to only look at past performance at other facilities, but "mandates a forward-looking analysis of what the facility [under review] can achieve in the future." *Id*. at *32. Thus, the agency cannot reject the use of a certain technology based on the lack of testing data for that technology, where the record otherwise establishes that the technology is appropriate as an engineering matter. NSR Manual, at B.5.

[299] NSR Manual at B.5.

[300] *In re Mississippi Lime*, 15 E.A.D. --, slip op. at 17; *In re Knauf,* 8 E.A.D. at 123-24.

[301] *In re Mississippi Lime*, slip op. at 17; *In re Knauf*. at 131

[302] *In re: Genesee Power Station Ltd. Partnership,* 4 E.A.D. 832, 835 (EAB 1993)

[303] *See* 42 U.S.C. § 7479(3) ("permitting authority" makes BACT determination); 40 C.F.R. § 70.7(a)(5).

[304] NSR Manual, p. B.24.

VI.B BACT is Typically Evaluated Through a 5-Step, Top-Down Process

EPA established the top-down process described in the NSR Manual in order to ensure that a BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that BACT represent the maximum achievable reduction.[305] While an agency is not required to utilize the top-down process as laid out in the NSR Manual, where it purports to do so, the process must be applied in a "reasoned and justified manner."[306] As the U.S. Environmental Appeals Board ("EAB")[307] recently explained:

> The NSR Manual's "top-down" method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the "top," or most stringent alternative, that the analysis presumptively ends there and the top option selected — "unless" technical considerations lead to the conclusion that the top option is not "achievable" in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate.[308]

More specifically, the top-down BACT process consists of five steps that are discussed in detail in Section B of the NSR Manual.

1. Identify All Available Control Options

The first step in the BACT process is to identify "all potentially available control options."[309] The goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options," including LAER, is compiled.[310] As the EAB has emphasized, "available is used in its broadest sense under the first step and refers to control options with a 'practical *potential* for application to the emission unit under evaluation."[311] A control option is considered "available" if "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable

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305 *Alaska Dept. of Envtl. Conservation v. EPA*, 540 U.S. 461, 485 (2004).

306 *Alaska Dept. of Envtl. Conservation v. EPA*, 298 F.3d at 822.

307 The EAB is EPA's supreme adjudicative body. *See* Changes to Regulations to Reflect the Role of the New Environmental Appeals Board in Agency Adjudications, 57 Fed. Reg. 5320 (Feb. 13, 1992). EAB decisions represent the position of the EPA Administrator with respect to the matters brought before it. *See Tenn. Valley Auth. v. EPA*, 278 F.3d 1184, 1198–99 (11th Cir. 2002) (finding EAB decision to be "final agency action").

308 *In re NMU,* slip op. at 13.

309 *In re Mississippi Lime,* slip op. at 11.

310 *In re Knauf*, 8 E.A.D. at 130.

311 *Id.* (*emphasis* in original).

reduction in emissions of regulated pollutants or will otherwise represent BACT."[312] The definition of BACT requires that the options considered include "application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."[313]

2. Eliminate Technically Infeasible Options.

Step two of the BACT process involves evaluating the technical feasibility of the available options and eliminating those that are not feasible.[314] Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology.[315] Feasibility is presumed if a technology has been used on the same or similar type of source in the past.[316] This step in the analysis has a purely technical focus and does not involve the consideration of economic or financial factors (including project financing). A demonstration of technical infeasibility should be clearly documented and must show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.[317]

3. Rank Remaining Control Technologies by Control Effectiveness

The next step in BACT process is to rank the available and feasible control technologies for each pollutant in order of effectiveness.[318] That is, for each pollutant, the most effective control option is ranked first, and relatively less effective options follow with the least effective option ranked last. The evaluation should address control effectiveness (percent pollutant removed); expected emission rate (tons per year); expected emission reduction (tons per year); energy impacts (Btu, kWh); environmental impacts (other media and the emissions of toxic and hazardous air emissions); and economic impacts (total cost effectiveness, incremental cost effectiveness).[319]

[312] *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm'r June 9, 1989).

[313] 42 U.S.C. § 7479(3).

[314] NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11.

[315] *Id.*; *In re Knauf,* 8 E.A.D. at 130.

[316] *Id*.

[317] NSR Manual, Table B-1.

[318] *In re Mississippi Lime*, slip op. at 12.

[319] NSR Manual, Table B-1.

4. Evaluate the Most Effective Controls and Document the Results

The fourth step in the BACT process is to evaluate the collateral economic, environmental and energy impacts of the various control technologies.[320] This step typically focuses on evaluating both the average and incremental cost-effectiveness of a pollution control option in terms of the dollars per ton of pollution emission reduced.[321] The point of this review is to either confirm the most stringent control technology as BACT, considering economic, environmental, or energy concerns, or to specifically justify the selection of a less stringent technology based on consideration of these factors.[322] This step is not relevant to a LAER analysis or an analysis under the SJAPCD's definition of BACT under Rule 2201.

5. Select BACT /LAER

The final step in the BACT process is to select the most effective control option remaining after Step 4. This option must represent the "maximum degree of reduction… that is achievable" after "taking into account energy, environmental, and economic impacts and other costs." BACT is an emissions limitation based on the most effective control option. The reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source and the technology must be specified in the permit.[323] "BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements)."

Under the District's BACT definition in Rule 2201, the final step is to choose the most stringent emission limitation of the four options in Section 3.1.

VI.C The PDOC's BACT Determinations Do Not Address All Pollutants Subject to Rule 2201 BACT Requirements

The District recognizes that pursuant to SJVAPCD Rule 2201, Section 4.1.1, BACT requirements are "triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis" for "any new emissions unit with a potential to emit exceeding

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320 NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12.

321 *In re Mississippi Lime*, slip op. at 12.

322 *Id.*

323 NSR Manual, p. B.56.

2.0 pounds in any one day."[324] The PDOC, however, does not provide a table summarizing daily potential to emit (termed "daily post-project potential to emit" or "maximum daily PE2" by the District), which would enable the reviewer to quickly determine which emissions units exceed the 2.0 lbs/day BACT threshold for each pollutant. Instead, the PDOC in Section VIII, pp. 106-109, presents a one to two-paragraph discussion of BACT applicability under SJVAPCD Rule 2201 for each emissions unit based on the daily potential to emit for pollutants for each emissions unit presented earlier in the document in Section VII.C.2, pp. 68-92. The lack of a summary table not only needlessly requires the reviewer to thumb through 25 pages of text to determine whether the District's determinations of BACT applicability are consistent with its emission calculations, it obscures the fact that these BACT applicability determinations (and consequently its BACT analyses presented in Appendix C) are incomplete and do not comply with the requirements of SJVAPCD Rule 2201.

Affected pollutants under the rule include:

> those pollutants for which an Ambient Air Quality Standard has been established by the EPA or by the California Air Resources Board (ARB), and the precursors to such pollutants, and those pollutants regulated by the EPA under the Federal Clean Air Act or by the ARB under the Health and Safety Code including, but not limited to, VOC, NOx, SOx, PM2.5, PM10, CO, and those pollutants which the EPA, after due process, or the ARB or the APCO, after public hearing, determine may have a significant adverse effect on the environment, the public health, or the public welfare.[325]

Here, the PDOC presents "Daily Post-Project Potential to Emit" for only six pollutants/ precursors: NOx, SOx, PM10, CO, VOC, and NH_3.[326] The PDOC does not establish the daily potential to emit for all pollutants (or their precursors) for which an ambient air quality standard has been established or which were determined to potentially have a significant adverse effect on the environment, the public health, or the public welfare and therefore does not correctly determine applicability of BACT pursuant to SJVAPCD Rule 2201.

Table 3 below summarizes the daily potential to emit from the Project's emissions units exceeding the 2.0 lbs/day BACT applicability threshold for NOx, CO, VOC, SOx, PM10, PM2.5, NH_3, and H_2S compared to the BACT analyses for each emissions unit and pollutant performed by the District (shaded gray).

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324 PDOC, p. 106.

325 SJVAPCD Rule 2201, Section 3.4.

Table 3: Daily potential to emit from HECA Project emissions units exceeding the 2.0 lbs/day BACT applicability threshold established in SJVAPCD Rule 2201 and BACT analyses performed by District

Emissions Unit	Emissions Unit ID	NOx[a] (lbs/day)	CO[a] (lbs/day)	VOC[a] (lbs/day)	SOx[a] (lbs/day)	PM10[a] (lbs/day)	PM2.5[b] (lbs/day)	NH_3[a] (lbs/day)	H_2S[c] (lbs/day)
Rail Car Unloading and Transfer System	S-7616-17-0					4.1	4.1		
Truck Unloading and Transfer System	S-7616-18-0					16.5	16.5		
Feedstock Storage, Blending, and Reclaim System	S-7616-19-0								
Feedstock Grinding, Crushing and Drying Operation	S-7616-20-0					5.2	5.2		
Gasification Solids Material Handling and Storage System	S-7616-22-0					3.6	3.6		
SRU Tail Gas Thermal Oxidizer	S-7616-23-0	535.7	449.1	12.3	51.9	17.0	17.0		
CO_2 Recovery and Vent System	S-7616-24-0		3,444.5	11,8916.4					**143.5**
Auxiliary Boiler	S-7616-25-0	30.7	189.1	20.4	14.6	25.6	25.6		
HRSG	S-7616-26-0	600.0	439.2	84.0	98.4	309.6	309.6	444.0	
Coal Dryer	S-7616-26-0	105.6	76.8	14.4	21.6	33.6	33.6	76.8	
Cooling Tower for Gasification Block and Process Units	S-7616-27-0					87.9	52.7		
Cooling Tower for Air Separation Unit	S-7616-28-0					8.1	4.9		
Cooling Tower for Power Block	S-7616-29-0					51.3	30.8		
Gasification Flare	S-7616-30-0	2,399.0	29,335.2	11.1	18.8	26.4	26.4		
SRU Flare	S-7616-31-0	59.3	70.2		441.6	2.6	2.6		
Rectisol Flare	S-7616-32-0	234.1	275.8	4.5	120.0	10.3	10.3		
Ammonia Synthesis Plant Startup Heater	S-7616-33-0	14.8	49.7	5.4	3.8	6.7	6.7		
Urea Unit with Urea Pastillation System	S-7616-34-0							314.4	
Nitric Acid Unit	S-7616-35-0	100.2						12.0	
Ammonium Nitrate Unit	S-7616-36-0					4.8	4.8		
Urea Storage and Handling Operation	S-7616-37-0					5.7	5.7		
Emergency Generator I	S-7616-38-0	77.3	402.0	46.4		10.8	10.8		
Emergency Generator II	S-7616-39-0	77.3	402.0	46.4		10.8	10.8		
Fire Water Pump	S-7616-40-0	44.1	76.5	4.1					
Fugitive Emissions from Gasification System (#1-#2 and #4-#10)	S-7616-21-0		24.4	90.5					**3.4**
Fugitive Emissions from SRU (#11-#12)	S-7616-23-0		**2.7**						**2.1**
Fugitive Emissions from Ammonia Synthesis Plant Startup Heater (#13-#21)	S-7616-33-0		5.9					**20.8**	**2.6**

Bolded values were not included in the PDOC's determination of daily potential to emit;
gray areas indicate BACT analyses included in the PDOC.

a Daily potential to emit for NOx, CO, VOC, SOx, PM10 and NH_3 from PDOC, Section VII.C.2, with the exception of fugitive emissions which were based on the 1/10/2013 HECA Updated Emissions Data and calculated as (maximum hourly emissions) × (24 hours/day) for each of the three process areas.

b With the exception of the cooling towers, daily potential to emit for PM2.5 was assumed the same as daily potential to emit for PM10. For the cooling towers, a fraction ratio of 0.6 PM2.5:PM10 was assumed consistent with the PDOC (Section VI, p. 33).

c Daily potential to emit for H_2S based on 1/10/2013 HECA Updated Emissions Data and calculated as (maximum hourly emissions) × (24 hours/day).

PM2.5 BACT

While the PDOC recognizes PM2.5 as a regulated pollutant for which ambient air quality standards have been established, it does not present a daily potential to emit for each emissions unit for this pollutant[327] and consequently does not determine BACT applicability for this pollutant for any emissions unit. As a result, the PDOC's BACT analyses do not provide separate BACT determinations for PM2.5 emissions, instead only determining BACT for PM10.[328] The Facility would have many units that exceed the 2 lb/day threshold as shown in Table 3 above. The District must establish BACT emission limits for PM2.5 emissions from each of these emissions units.

Ammonia BACT

While the PDOC determines the daily potential to emit for ammonia emissions from the HRSG and coal dryer vent, it argues that ammonia emissions are intrinsic to the operation of the SCR system and as such are not subject to BACT.[329] This is not acceptable as the District's rules do not provide for an exemption from BACT for control devices.

Further, the District fails to identify BACT applicability for ammonia emissions from the urea absorbers (314.4 lbs/day) and from the nitric acid unit (12.0 lbs/day), which by far exceed the 2.0 lbs/day threshold established in SJVAPCD Rule 2201.[330] The District must establish BACT emission limits for ammonia emissions from these emissions units.

Hydrogen Sulfide BACT

The PDOC does not present a daily potential to emit for the pollutant H_2S for which CARB established a 1-hour ambient air quality standard of 0.03 ppm in 1969.[331] Based on the emission calculations provided elsewhere, the H_2S emissions from the CO_2 vent can be calculated at 143.5 lbs/day and from fugitive equipment leaks assigned to the gasification system at 3.4 lbs/day, to the SRU at 2.2 lbs/day, and to the ammonia

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327 *See* PDOC, Section VII.C.2, pp. 70-93.

328 PDOC, pp. 106-109 and 112-116 and Appx. B and C.

329 PDOC, p. 106.

330 *See* PDOC, p. 88.

331 CARB, History of Hydrogen Sulfide Ambient Air Quality Standard, http://www.arb.ca.gov/research/aaqs/caaqs/h2s/h2s.htm.

synthesis plant startup heater at 2.6 lbs/day.[332] Consequently, the PDOC fails to determine BACT applicability and provide BACT analyses for H_2S emissions from the CO_2 vent and fugitive H_2S emissions from equipment leaks. The District must establish BACT emission limits hydrogen sulfide emissions from these emissions units.

Other Inadequate BACT Determinations

The PDOC recognizes that BACT pursuant to SJVAPCD Rule 2201 is triggered for SOx emissions from the sulfur recovery unit[333] and provides a BACT analysis in Appendix C. The PDOC calculates emissions of NOx, CO, VOC, and PM10 from the SRU tail gas thermal oxidizer in excess of the 2.0 lbs/day threshold but fails to determine that BACT is applicable and consequently fails to provide BACT analyses for these pollutants for the sulfur recovery unit.

Further, the PDOC calculates that PM10 emissions from the urea storage and handling unit at 5.7 lbs/day[334] but then erroneously claims that the daily potential to emit for PM10 from this emissions unit is less than 2.0 lbs/day.[335] Consequently, the PDOC fails to provide a BACT analysis for PM10 emissions from the urea storage and handling unit.

The PDOC's BACT applicability determination also fails to determine BACT for fugitive CO emissions from fugitive equipment leaks.

The PDOC must be revised to adequately demonstrate compliance with the BACT requirements of SJVAPCD Rule 2201 addressing the above discussed issues as well as other pollutant emissions that are covered under this rule (*e.g.,* sulfates).

VI.D The PDOC's BACT Determinations Pursuant to Rule 2201 BACT Requirements Are Inadequate

The PDOC recognizes that the Project is subject to the requirements of SJVAPCD Rule 2410, Prevention of Significant Deterioration, for NO_2, CO, PM, PM10, and GHG emissions.[336] The District finds that NOx, CO, PM and PM10 BACT requirements

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[332] Based on 1/10/2013 HECA Updated Emissions Data:
CO_2 vent: (5.98 lbs/hour H_2S) × (24 hours/day); fugitives gasification system (process areas #1, #2, #4-#10): (0.62 tons/year)/(356 days/year)×(2,000 lbs/ton); fugitives SRU (process areas #11 and #12): (0.39 tons/year)/(356 days/year)×(2,000 lbs/ton); fugitives ammonia synthesis startup heater (process areas #13-#21): (0.62 tons/year)/(356 days/year)×(2,000 lbs/ton).

[333] PDOC, p. 107.

[334] PDOC, p. 90.

[335] PDOC, p. 109.

[336] PDOC, p. 143.

pursuant to SJVAPCD Rule 2410 are satisfied by compliance with Rule 2201 requirements because the latter contains a more stringent definition of BACT. This finding and the District's later BACT analyses ignores the fact that under SJVAPCD Rule 2201, BACT requirements are triggered on an emissions unit-by-emissions unit basis whereas Rule 2410 requires BACT on a facility-wide basis and does not have a de minimus exemption for equipment emitting less than 2.0 lbs/day.

VI.E Common Problems with the PDOC's Approach to BACT Determinations

The District has never evaluated or permitted an IGCC plant prior to the HECA application. Yet, for most BACT determinations, the PDOC simply fits the unique HECA facility into the outdated existing off-the-shelf generic BACT determinations contained in the District's BACT Guidelines. The PDOC does not address or consider whether the novel nature of the HECA facility, relative to earlier facilities permitted by the District, necessitates facility-specific BACT determinations instead of simply adapting the closest generic BACT Guideline to HECA. (Worse yet, the PDOC incorporates several BACT Guidelines as the basis for its BACT determinations that were modeled after the Project at hand.[337])

For example, as discussed in detail in Comment VI.F below, air cooling is in common use at both combined-cycle power plants and refineries, and an IGCC plant includes elements of both of these facility types. Air cooling would serve the exact same function as the proposed wet cooling towers at HECA. Air cooling would not redefine the source even by the Applicants' narrow definition, *i.e.*, an IGCC facility intended to convert coal and petcoke to hydrogen-rich syngas for combustion and for manufacture of ammonia-based fertilizer products. The PDOC's BACT analysis does not mention air-cooling but instead only references a SJVAPCD generic cooling tower BACT determination last updated in June 2000. June 2000 pre-dates the online date of any of the operational air-cooled combined cycle plants in California.[338] The PDOC's failure to evaluate an air cooling alternative to the proposed wet cooling towers is a substantial deficiency in the document.

A similar failure occurs with the BACT determination for the HECA flares, as discussed in more detail in Comment VI.G. The PDOC references a SJVAPCD generic

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[337] For example, SJVAPCD, BACT Guidelines X.Y.Z for "Combustion Turbine Generator – Fired on Hydrogen-rich Syngas and Natural Gas, Uniform and Variable Load, With or Without Heat Recovery," dated November xx, 2010; "Coal/Coke Gasification CO_2 Recovery System," dated December xx, 2009; "Nitric Acid Unit," dated January xx, 2013; and "Ammonia Nitrate Unit," dated January xx, 2013.

[338] The first air-cooled combined cycle plant in California, Calpine's Sutter Power Plant, became operational in the summer of 2001. *See* California Energy Commission's webpage for the Sutter Power Plant "Key Dates;"http://www.energy.ca.gov/sitingcases/sutterpower/.

refinery flare BACT determination last updated in June 2006. No new refineries have been built in the SJVAPCD in decades and the last new refinery proposed, the Big West Refinery in Bakersfield, included a ground flare as opposed to the elevated flares proposed for the HECA Project.[339]

The use by SJVAPCD of outdated generic BACT determinations for the cooling process and flares at HECA is inconsistent with the technology-forcing nature of BACT. The SJVAPCD's definition of BACT is "the most stringent emissions limit… achieved in practice." What constitutes "achieved in practice" changes over time with technological advances. The reliance of the PDOC on the District's outdated generic BACT guidelines is inconsistent with the fundamental purpose of BACT.

VI.F BACT Determination for Cooling Towers Is Deficient

The proposed wet cooling towers (S-7616-27-0, S-7616-28-0, and S-7616-29-0) account for 83 percent of the water used at the HECA Project. The combined circulating water flow rate of the three HECA Project cooling towers is 303,500 gallons per minute ("gpm"); approximately 95,500 gpm of water will be circulated in the power block cooling tower; the air separation unit ("ASU") cooling tower circulation rate is approximately 45,000 gpm; and the process tower circulation rate is about 163,000 gpm.[340] Evaporation of the water in these cooling towers will result in particulate matter emissions. The three proposed wet cooling towers are the second largest source of PM10 and PM2.5 emissions at HECA after the combined cycle plant stacks, with projected emission rates of 26 tons/year PM10 and 16 tons/year PM2.5, contributing 29% and 20% of total Project emissions, respectively.[341] Air cooling would eliminate these PM10 and PM2.5 emissions and substantially reduce the Project's adverse impacts on air quality.

The PDOC's BACT analysis for cooling towers references SJVAPCD BACT Guideline 8.3.10, "Cooling Tower – Induced Draft, Evaporative Cooling."[342] This guideline identifies technologically feasible BACT for PM10 emissions from cooling towers as a cellular type drift eliminator. No other control alternatives are identified as achieved in practice or as an alternate.

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[339] EPA, Region 9, Revised Statement of Basis and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit – Big West of California LLC, November 29, 2007, p. 5. "The air pollution control equipment and techniques at the plant will consist of the following… A multipoint ground flare equipped with a flare gas recovery system."

[340] PDOC, p. 32.

[341] PDOC, p. 93.

[342] PDOC, Appendix C, p. C-20.

The obvious alternative to eliminate PM10 and PM2.5 emissions from cooling processes at HECA is to utilize air cooling. It is common practice to use air-cooled condensers on combined-cycle plants in California. For example, Colusa Generating Station, Gateway Generating Station, Otay Mesa Power Plant, and Sutter Power Plant are all operational combined-cycle plants in California that rely on air-cooled condenser technology.[343] Air-cooled condensers have zero emissions of PM10 and PM2.5. The fact that this cooling technology is in common use on California combined-cycle plants verifies that this cooling technology is achieved in practice as well as cost-feasible on combined-cycle plants in the state.

IGCC plant manufacturers also offer air cooling as a standard option for the entire plant. For example, for the last decade ConocoPhillips has advertised in public forums an air-cooled option to its standard IGCC plant design.[344] Air cooling was also evaluated by Powers Engineering as an alternative to cooling towers for the proposed Big West Refinery in Bakersfield in 2007.[345]

Thus, air cooling can be considered as "achieved in practice" and should be required as BACT without regard to costs, as required under California state law. However, even if cost were an issue, Sierra Club demonstrates below that air cooling would be cost-effective and should therefore be required as BACT.

VI.F.1 Cost of Cooling Towers and Associated Infrastructure at HECA

The cost of cooling tower capacity has been extensively studied in California. A comprehensive analysis of cooling tower retrofit costs at eleven coastal boiler plants in California, jointly contracted by the State Water Resources Control Board ("SWRCB") and the Ocean Protection Council ("OPC"), determined a retrofit cost range of $88 per kilowatt ("kW") to $151/kW for conventional cooling towers.[346] EPA indicates that the

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343 CEC, Colusa Generating Station (CGS) Electrical Power Plant Project, Docket No. 06-AFC-09; http://energy.ca.gov/sitingcases/colusa/; CEC, Gateway Generating Station Power Project (formerly Gateway Contra Costa), Docket No. 00-AFC-01; http://energy.ca.gov/sitingcases/gateway/; PG&E Currents, Gateway Generating Station; http://www.pgecurrents.com/2012/08/07/climate-change-comes-to-the-power-industry/200x300_gateway-photo-3-2/; CEC, Otay Mesa Power Plant Licensing Case, Docket No. 99-AFC-05; http://energy.ca.gov/sitingcases/otaymesa/; CEC, Sutter Power Plant Project, Docket No. 97-AFC-02; http://energy.ca.gov/sitingcases/sutterpower/.

344 R. Herbanek, T. Lynch – ConocoPhillips, E-Gas Applications for Sub-Bituminous Coal, presented at Gasification Technologies 2005, San Francisco, October 11, 2005.

345 *See* Exhibit N, Bill Powers, Powers Engineering Comments on Big West CFP DEIR, March 27, 2007.

346 TetraTech, California's Coastal Power Plants: Alternative Cooling System Analysis, February 2008. Eleven coastal steam boiler plants were included in the study. Nine of them fall within the $88/kW to $151/kW range. The cost of a conventional cooling tower retrofit at one plant not included in the range, Pittsburg Power Plant in the Bay Area, was an outlier at $193/kW. The reason for the higher cost at this plant is the relatively high expense of the circulating water piping due to the distance, approximately 4,000 feet, from the boilers to the cooling towers. One plant, Scattergood Power Plant adjacent to the Los

incremental cost of a retrofit cooling tower is approximately 20 percent greater than new construction.[347] Converting the range of California retrofit conventional cooling tower costs to new cooling tower construction gives a range of $70/kW to $121/kW. The median capital cost for a new conventional cooling tower, based on these data, would be approximately $95/kW.

One plant included in the SWRCB/OPC cooling tower retrofit study, the 803-MW Scattergood Power Plant adjacent to Los Angeles International Airport, would utilize a conservatively-designed plume-abated cooling tower, with an approach temperature of 12 F and a range of approximately 18 F. The collective flow rate for the three proposed retrofit cooling towers at Scattergood is 344,000 gpm.[348] The projected cost of the plume-abated cooling towers at Scattergood, in 2008 dollars, is $200/kW. Converting this retrofit cooling tower cost to a new construction cost would reduce the cost to $160/kW. Also, the proposed cooling tower flow rate at Scattergood, 344,000 gpm, is about 13 percent greater than the cooling tower flow rate at HECA of 303,500 gpm. Adjusting the Scattergood plume-abated cooling tower cost estimate to the new construction cost and a 13 percent reduction in flow rate gives an adjusted new plume-abated cooling tower cost for HECA of about $140/kW. This is equivalent to a plume-abated cooling tower capital cost at HECA of $112 million. The projected annualized cost of plume-abated cooling towers at HECA is provided in Table 4a below.

Angeles International Airport would utilize a conservatively-designed plume-abated cooling tower, with an approach temperature of 12 F and a range of approximately 18 F. The collective flow rate for the three proposed cooling towers at Scattergood is 344,000 gpm. The projected cost of the plume-abated cooling towers at Scattergood, in 2008 dollars, is $200/kW.

347 EPA, Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule, April 2002, p. 2-33. "Additional Cooling Tower Retrofit Scaling Factor: 20 percent."

348 TetraTech, California's Coastal Power Plants: Alternative Cooling System Analysis, February 2008, Chapter O.

Table 4a: Annualized cost of cooling system at HECA, plume-abated cooling towers

Element	Capital Cost ($MM)	Annualized Capital Cost ($MM/year)	O&M Cost ($MM/year)	Annual Cost or Delivery Cost ($MM/year)
Five groundwater extraction wells (7,500 AFY)	$3 million ($0.6 million/well)	$0.3 million	not calculated	$0.3 million/year
15-mile pipeline from wells to HECA	$8 million	$0.8 million/year	not calculated	$0.8 million/year
Raw water			NA	$3.4 million/year (7,500 AFY × $450)
Raw water OMP&R rate O&M, power, replacement			not calculated	
Raw water treatment plant	$14 million	$1.3 million/year	not calculated	$1.3 million/year
Power block cooling tower	$112 million (plume-abated)	$10.6 million/year	3.5 million/year	$14.1 million/year
Process cooling tower				
Air separation unit cooling tower				
ZLD processing plant	$22 million	$2.3 million/year	2.5 million/year	$4.8 million/year
Total:				**$24.7 million/year**

Notes:
1) AFY = acre-foot per year; O&M = operation and maintenance; OMP&R = operation, maintenance, power, and replacement; ZLD = zero-liquid discharge.
2) All capital costs are assumed to be amortized over 20 years at 7% interest (capital recovery factor = 0.0944).
3) Groundwater well and pipeline cost based on: HDR, Inc., *2011 South Central Texas Regional Water Plan.*
4) *Volume II – September 2010, Appendix A Cost Estimation Procedures South Central Texas Region*, Tables A-3 and A-10, p. A-4 and p. A-10.
5) Raw water cost: HECA, Revised HECA Application for Certification, June 2009, Appendix O (BVWSD contract with HECA).
6) Raw water treatment plant cost based on: CH2MHill, *Lebanon (OR) Water System Master Plan - Water Treatment Plant and Source Water Analysis*, May 2007, Exhibit 7-14, p. 35 Capital Cost Comparison of Selected WTP/Intake Alternatives, Initial Plant Capacity = 6 mgd, average capital cost ~$14 million.
7) TetraTech, *California's Coastal Power Plants: Alternative Cooling System Analysis*, February 2008, Chapter O, Scattergood Power Plant, Table O-4, p. O-3. 344,000 gpm circulating water flow rate.
8) Water Reuse Foundation, *Survey of High Recovery and Zero Liquid Discharge Technologies for Water Utilities*, 2008, Table 5.1, p. 44. Case 4, 1.0 mgd ZLD facility, 12,000 ppm TDS.

Table 4b provides the projected annualized cost of conventional cooling towers at HECA, which is approximately $76 million.

Table 4b: Annualized cost of cooling system at HECA, assuming conventional cooling towers

Element	Capital Cost ($MM)	Annualized Capital Cost ($MM/year)	O&M Cost ($/year)	Annual Cost or Delivery Cost ($/year)
Five groundwater extraction wells (7,500 AFY)	$3 million ($0.6 MM/well)	$0.3 million	not calculated	$0.3 million
15-mile pipeline from wells to HECA	$8 million	$0.8 million/year	not calculated	$0.8 million/year
Raw water			NA	$3.4 million/year (7,500 AFY × $450)
Raw water OMP&R rate (O&M, power, replacement)			not calculated	
Raw water treatment plant	$14 million	$1.3 million/year		$1.3 million/year
Power block cooling tower	$76 million (conventional)	$7.2 million/year	3.5 million/year	$10.7 million/year
Process cooling tower				
Air separation unit cooling tower				
ZLD processing plant	$22 million	$2.3 million/year	2.5 million/year	$4.8 million/year
Total:				**$21.3 million/year**

As shown, the annual costs to HECA to utilize conventional cooling towers will be in the range of $21 to $25 million per year.

VI.F.2 Capital Cost of Air-Cooled Condenser(s) to Substitute for Cooling Towers at HECA

A comparison of the capital and operating costs of air-cooled condenser ("ACC") capacity to substitute for cooling towers was conducted by Powers Engineering for a proposed coal plant in Wisconsin.[349] A cooling tower consisting of 12 cells and a cooling water circulation rate of 250,650 gpm was specified by the developer for Weston Unit 4, a coal-fired plant in Wisconsin. Substituting an air-cooled condenser with a 35 F initial temperature difference ("ITD") for the cooling tower in the Weston Unit 4 application would require 66 cells and cost approximately $66 million in 2005 dollars. The total cooling tower flow rate at HECA is 303,500 gpm. Therefore the total number of ACC cells needed at HECA would be: (303,500 gpm)/(250,650 gpm) × 66 cells = 80 cells at $80 million in 2005 dollars. This translates to about $100 million in 2012 dollars.[350]

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[349] Bill Powers, Powers Engineering, Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler, June 2005.

[350] Chemical Engineering, Economic Indicators, July 2012. Chemical Engineering Plant Cost Index ("CEPCI") in 2005 = 468.2; CEPCI in April 2012 = 596.0. Therefore cost increase from 2005 to 2012 would be: 596.0/468.2 = 1.27.

For a 35 F ITD ACC the air cooling heat rate penalty at design conditions is 2.8 percent relative to a conventional wet tower, and the annual average heat rate penalty is approximately 1.5 percent. At 20-year amortization at 7 percent interest, the annual cost of this air-cooled condenser capacity would be about $9.5 million. Assuming 250 horsepower ("hp") fans, the continuous fan energy cost at a wholesale electricity cost of $30 per Megawatt-hour ("MWh") and 37 percent annual capacity factor would be about $1.5 million/year.[351,352,353] The total annual cost of the ACC option would be in the range of $11 million/year without accounting for the 1.5% overall efficiency penalty.

The HECA combined cycle plant will generate a gross output of 431 MW. A 1.5% annual efficiency penalty would reduce gross output from 431 MW to about 424 MW, a reduction of 6.5 MW. The cost of the 1.5% annual efficiency penalty would be $0.6 million/year.[354] The power block appears to use about half of HECA's cooling capacity based on the description of the three cooling towers in the PDOC.[355] Assuming the 1.5% power block efficiency penalty imposed by the 35 F ITD air-cooled condenser is comparable to the efficiency penalty imposed on the cooling capacity servicing process units, an additional $0.6 million/year in efficiency penalty would apply to process cooling as well. It is important to note that fin-fan air coolers could serve the process cooling requirement, as described in Exhibit N to these comments.

VI.F.3 Air Cooling Should Be PM10/PM2.5 BACT for Cooling Processes at HECA

As explained above, under the District's definition of BACT, the District's BACT definition does not allow a consideration of costs for control techniques that have been achieved in practice." Since air cooling has been achieved in practice, costs cannot be considered. The Applicant's consultant nonetheless prepared a cost-effectiveness analysis. This cost-effectivenesss analysis should not be considered, as the District

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[351] DOE, Energy Information Administration, Today in Energy - 2012 Brief: Average wholesale electricity prices down compared to last year, January 9, 2013. Average Southern California wholesale electricity price in 2012, $30/MWh.

[352] CEC, Staff Paper – Thermal Efficiency of Gas-Fired Generation in California: 2012 Update, March 2013, Table 2, p. 5. Average capacity factor of California combined cycle fleet in 2012 = 36.8%.

[353] Assume wholesale energy cost of $0.03/kWh. 250 hp/cell × 80 cells = 20,000 hp (14,920 kW). Annual fan operating cost would be: $0.03/kWh × 14,920 kW × 8,760 hr/year × 0.37 (capacity factor) = $1.5 million/year.

[354] 431 MW × $30/MWh × 8,760 hr/year × 0.37 × 0.015 = $0.63 million/year.

[355] PDOC, p. 63.

acknowledges. Sierra Club nonetheless discusses the problems with the Applicants' cost analysis below.

The total estimated cost of the air cooling alternative to cooling towers at HECA is approximately $12 million/year. This is below the estimated $21 to $25 million/year "all-in" cost of cooling towers and associated water supply and wastewater disposal infrastructure at HECA. Use of air cooling at HECA would lower PM10 and PM2.5 emissions and not increase costs. For these reasons, the PDOC should have identified air cooling as BACT for cooling processes at HECA.

The BACT comparative cost-effectiveness calculation of air-cooling and wet cooling towers at HECA prepared by the Applicant's consultant, URS, includes only the cost of the wet cooling towers in the calculation of PM10 control cost effectiveness. As HECA acknowledges, the overwhelming majority of the water consumption at HECA, 83 to 85%, is associated with cooling tower evaporative losses and blowdown losses.[356] All components associated with water supply, including the groundwater wells, 15-mile water pipeline to HECA, raw water treatment, cooling towers, and zero liquid discharge system as well as the cost of offsets for particulate matter emissions must be included in the total wet cooling cost-effectiveness calculation to allow an apples-to-apples comparison with the air cooling option. When this is done, air cooling is a lower-cost alternative to cooling towers that eliminates cooling tower PM10 and PM2.5 emissions. The air cooling cost calculation carried-out by URS should be given no weight by the SJVAPCD, as it fails to include many substantial cost elements that are essential and integral to the proper functioning of the cooling towers.

Fluor Corporation conducted a water minimization study for the HECA Project power block cooling system in January 2008.[357] Fluor identified a total process makeup water requirement for HECA of 5,134 gpm, of which 4,983 gpm was associated with the cooling towers. Fluor identifies the cooling tower(s) as responsible for 97% of total plant makeup water consumption. [358]

The Fluor study is inadequately documented. There are three cooling towers proposed at the HECA Project, yet the Fluor study evaluates in detail only the impact on water use of substituting the largest of the cooling towers, the power block cooling

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[356] HECA Responses to Sierra Club Data Requests – Nos. 98 through 131, December 2012, p. 126-1; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[357] Fluor Corporation, HECA Water Minimization Study, prepared for Hydrogen Energy International LLC, Contract: A3RW, Revision 0, January 3, 2008 (Appendix X to Revised HECA Application to CEC, May 2009); http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/applicant/revised_afc/Volume_II/Appendix%20X.pdf.

[358] *Ibid*, p. 7.

tower, with air cooling or a combination wet-dry cooling system. For this reason, the study shows a relatively high residual water consumption rate even when the power block cooling tower is substituted by an air-cooled condenser.[359] Fluor did not evaluate substituting the other two cooling towers with an air-cooled alternative to largely eliminate the need for makeup water at the HECA Project.

Fluor provides insufficient information regarding the cooling tower and air-cooled condenser alternative to determine whether or not the capital cost delta of $37 million is reasonable. No design assumptions are provided for either the wet cooling tower or the air-cooled condenser.

The assumed annual efficiency penalty imposed by use of an air-cooled condenser in the Fluor study, 8.4 MW, is just under 2% for the HECA 431 MW (gross) combined cycle unit. This appears relatively accurate, based on the Weston Unit 4 wet versus dry cooling comparison in a cooler climate (Wisconsin), though no design information is provided for either the cooling tower or the air-cooled condenser to verify the annual efficiency penalty.

VI.F.1 Cooling Water with Lower TDS Content

Even if air cooling were rejected as BACT for the HECA Project's cooling demands, the PDOC's BACT analysis for the Project's three wet cooling towers is deficient because it fails to analyze the use of cooling water with substantially lower total dissolved solids ("TDS") content for the process and power block cooling towers. Reduced TDS content in the cooling water leads to proportionally lower PM10 and PM2.5. Pre-treating water to reduce the TDS content is clearly technically feasible and is required for the cooling water used in the cooling tower serving the ASU.[360] The Applicant has repeatedly expressed its unwillingness to subject water used for the other two cooling towers to the same treatment due to "significantly increased capital cost and parasitic energy consumption."[361] If the District concludes that wet cooling is BACT, the PDOC's BACT analysis for the wet cooling towers must include a cost-effectiveness analysis for treating cooling water for lower TDS content.

VI.G BACT Determination for Flares Is Deficient

The PDOC proposes three elevated flares for the HECA Project (S-7616-30-0, S-7616-31-0, and S-7616-32-0), primarily serving the gasification block, the sulfur

[359] *Ibid*, Tables 1 and 2, p. 3.

[360] PDOC, p. 15.

[361] For example, HECA Responses to CEC Data Requests Nos. A1 through A123, August 2012, p. A1-3; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-08-22_Applicant_Response_to_CEC_Data_Request_no-A1_through_A123_TN-66876.pdf.

recovery unit ("SRU"), and the Rectisol unit, with a purported CO and VOC destruction efficiency of ≥99%.[362] The PDOC references SJVAPCD BACT Guideline 1.4.8, "Refinery Flare," as the basis for the HECA Project BACT determination for flares.[363] The generic SJVAPCD BACT Guideline 1.4.8 for refinery flares identifies "engineered" air- and steam-assisted elevated flares VOC BACT as "achieved in practice." The elevated flare technology is identified in the SJVAPCD refinery flare BACT guideline as having a VOC destruction efficiency of ≥98%. (No definition of "engineered flare" is provided in the SJVAPCD BACT guideline document.) Presumably the SJVAPCD would require substantial supporting test data before making a determination that any elevated flare exceeds the BACT-level achieved-in-practice elevated flare performance of ≥98% identified by the SJVAPCD for refinery flares. Yet, no such supporting flare test data has been provided by HECA or is referenced by the SJVAPCD in stating that the flare VOC and CO destruction efficiency of the elevated flares at the HECA Project will be 99%.

VI.G.1 BACT Is the Use of Enclosed Ground Flares

The PDOC does not identify enclosed ground flares as demonstrated in practice, even though enclosed ground flares have been in common industrial use for decades, including at the ExxonMobil Refinery in Torrance, California[364] and have been proposed for the Big West Refinery in Bakersfield.[365]

Exposure of elevated flares to wind significantly reduces their combustion efficiencies. In addition direct monitoring of an elevated flare is not as feasible as it is with a ground flare. This could be remedied by the use of an enclosed ground flare for the expected periodic events associated with gasifier startup. The Bay Area Air Quality Management District ("BAAQMD"), where five large petroleum refineries are located, identifies use of an enclosed ground flare as "Technologically Feasible/ Cost Effective" BACT for flare VOC emissions.[366] The BAAQMD also assigns an assumed VOC destruction efficiency of ≥98.5% to an enclosed ground refinery flare[367], higher than the assumed destruction efficiency of ≥98% assumed by the BAAQMD for all other flares.

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362 PDOC, Appx. C, p. C-30.

363 PDOC, Appx. C, p. C-21.

364 HECA to Sierra Club Data Requests – Nos. 98 through 131, November 2012, p. 122-1.

365 EPA, Region 9, Revised Statement of Basis and Ambient Air Quality Impact Report for a Clean Air Act Prevention of Significant Deterioration Permit – Big West of California LLC, November 29, 2007, p. 5. "The air pollution control equipment and techniques at the plant will consist of the following … A multipoint ground flare equipped with a flare gas recovery system."

366 Bay Area Air Quality Management District, Best Available Control Technology (BACT) Guideline 82.1, Flares - Refinery, June 30, 1995; http://hank.baaqmd.gov/pmt/bactworkbook/default.htm.

367 *Ibid*.

This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds.

A single enclosed ground flare could readily accept maximum flare gas flow during the planned gasifier startups; the elevated flares proposed by HECA would also be necessary to handle higher flare gas volumes that could occur during major malfunctions or force majeure emergency events. Flares, either enclosed ground flares or elevated emergency flares, are relatively inexpensive pieces of equipment. The capital cost of an enclosed ground flare capable of handling 100 tons per hour of VOCs is approximately $4 to $5 million. An elevated flare capable of handling ten times this heat input under force majeure emergency conditions costs approximately $1.5 to $2 million. Flare BACT would be an enclosed ground flare to combust gasifier startup off-gases and elevated flares for all unplanned flaring events that exceed the capacity of the enclosed ground flare.

HECA asserts that there will be no malfunction flaring at HECA due to the high reliability of the gasifier technology that will be employed.[368] We discussed the improbability of this claim in Comment V.B.1. The assertion that there will be no malfunction flaring is also used as justification for not utilizing a flare gas recovery system, which is an integral component of the SJVAPCD definition of BACT for refinery flares.[369] Yet, the BACT analysis prepared by URS for the HECA Project lists many upset events that would result in flaring, stating: "*The gasification block will be provided with a relief system and associated gasification flare to safely dispose of gasifier streams during start-up, shut-down, and unplanned upsets or emergency events, syngas during AGR start-up, hydrogen-rich gas during short-term emergency combustion turbine outages, or other various streams within the Project during other unplanned upsets or equipment failures*."[370] URS acknowledges a reasonable range of malfunction events that cause unplanned flaring, yet the PDOC does not attempt to quantify some level of malfunction flaring events. Both the URS flare BACT analysis and the PDOC are deficient for failure to quantify malfunction emissions.

It is for this reason – the likelihood of substantial periods of malfunction flaring at HECA and subsequent startup flaring following the malfunction shutdown(s) – that use of an enclosed ground flare, combined with use of elevated flares to handle major upsets caused by power outages (for example), should be flare BACT for the facility.

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368 HECA Response to Sierra Club Data Request No. 62, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-12_Applicants_Supplemental_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67706.pdf.

369 SJVAPCD BACT Guideline 1.4.8: "Flare shall be equipped with a flare gas recovery system for non-emergency releases…"

370 Application, Appx. B, p. 55.

This is especially true given that HECA will not be installing flare gas recovery systems. The enclosed ground flare is a necessary component of the flare gas system in light of the failure by HECA to incorporate flare gas recovery system(s) in the plant design.

URS, the engineering consultant contracted by HECA to prepare permitting documentation, was part of a team of consultants that identified an enclosed ground flare as BACT for the proposed Pacific Mountain Energy Center ("PMEC") IGCC facility in Washington in 2006.[371] The estimated CO destruction efficiency of the enclosed ground flare was 99%.[372] The capacity of the enclosed ground flare for the gasification block at the Pacific Mountain Energy Center, at 3,730 MMBTU/hour, is essentially the same as the capacity of the proposed HECA gasification block flare at 4,000 MMBTU/hour.

Despite identifying an enclosed ground flare as BACT at PMEC, and acknowledging the superior CO destruction efficiency of enclosed ground flares relative to elevated flares, URS attempts to reject the enclosed ground flare as flare BACT for the HECA Project by stating: "*Compared to an elevated flare, an enclosed ground flare offers better CO destruction. However, enclosed ground flares pose potentially decreased dispersion of combustion gases and increased reliability concerns and have never been installed on any IGCC plants and so are considered unproven technology in this application with an associated risk*.[373] There are two operational coal-fired IGCC plants in the U.S., Wabash River IGCC and Polk Power Station IGCC, both of which were constructed almost 20 years ago.[374] The fact that there are only two such facilities puts the statement that "*(enclosed ground flares) have never been installed on any IGCC plants*" in context.

The advantages of enclosed ground flares are: reduced flame visibility, minimal heat and noise, ease of emissions sampling, smokeless combustion, and high destruction efficiencies attained by assuring the appropriate residence time.[375] Elevated flares are primarily elevated to reduce the impact of radiant heat and light during flaring events, not as a ground level impact air contaminant mitigation measure. Enclosed ground flares largely eliminate the effects on workers and nearby residents of radiant heat and light during flaring events. An enclosed ground flare has successfully operated at the ExxonMobil Refinery in Torrance, California for over two decades. The

[371] *Ibid*, p. 121-1.

[372] Pacific Mountain Energy Center, EFSEC Application 2006-01, Appendix B Air Quality – B.1 BACT Analysis, Enclosed Ground Flare Emission Rates, Geomatrix Consultants, March 30, 2007.

[373] Application, p. 55.

[374] www.clean-energy.us webpage "About IGCC Power": http://www.clean-energy.us/facts/igcc.htm#projects.

[375] Flare Industries, Inc., General Description - Enclosed Ground Flares; http://www.flareindustries.com/products/thermal-oxidizers-enclosed-flares/files/10-enclosed-ground-flares.pdf

Sierra Club requested, and URS declined, to provide the safety and performance history of the Torrance Refinery enclosed ground flare.[376] This reality undermines the credibility of URS claims of concern regarding use of an enclosed ground flare at the HECA Project.

An operational challenge for elevated flares during periodic flaring of relatively small volumes of process upset gases is susceptibility to poorer performance in crosswinds. The annual average wind speed at the Bakersfield Airport near Buttonwillow at 10 meter height is 6.4 miles per hour ("mph").[377] The height of the HECA Project flares will be at least 250 feet (~80 meters).[378] Average wind speed will be substantially higher at the 80 meter elevation than at the 10 meter elevation. Test data collected on elevated flares by EPA to establish a destruction efficiency of 98% for elevated flares were all gathered at crosswind speeds of 5 mph or less.[379]

Wind can significantly reduce flare efficiency. Even at low wind speeds (below 3.5 meter/second or 7.7 mph), flare efficiency can be as low as 70%, with even more significant decreases in efficiency at higher wind speeds.[380]

A leading flare manufacturer has highlighted the problems that can cause low flare efficiency and other flaring problems. John Zink co-authored an article published in *Hydrocarbon Processing* on refinery flares, which states:

> The problem. To the casual observer, it may seem relatively easy to minimize and even eliminate routine flaring from refineries and petrochemical/chemical plants. It appears that these plants are unnecessarily wasting energy and generating pollution. The main challenge is that it can be uneconomical to

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[376] HECA Responses to Sierra Club Data Requests Nos. 98 through 131, December 2012, p. 122-1; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf: 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."

[377] California Climate Data Archive, Average Wind Speed – Bakersfield, California; http://www.calclim.dri.edu/ccda/comparative/avgwind.html.

[378] HECA Responses to Sierra Club Data Requests – Nos. 98 through 131, November 2012, p. 119-1; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Response_to_the_Sierra_Clubs_Data_Request_Nos_98_through_131_TN-68729.pdf.

[379] M. McDaniel – Engineering Science, Inc., Flare Efficiency Study, EPA-600/2-83-052, July 1983, p. 19; http://www.epa.gov/ttn/chief/ap42/ch13/related/ref_01c13s05_jan1995.pdf.

[380] Douglas M. Leahey, Katherine Preston and Mel Strosher, "Theoretical and Observational Assessment of Flare Efficiency," 51 J. Air & Waste Mgmt. 1610, 1616 (2001); http://www.endocrinedisruption.com/files/W15958Leahey2001.pdf.

recover the gases, either for use in the plant or to sell as energy, for a variety of reasons.

> The flowrate and composition of the waste gases going to the flare are often highly variable. The unsteady flow … and variable composition … make it difficult to use the waste gases elsewhere in the plant where the energy demand is normally steady. The variable composition makes it difficult to sell, unless a purification system is added to produce a more consistent composition.
>
> The waste gases may have a low heating value, which means that equipment such as burners must be properly designed for the low heating value. The waste gases may be off-spec product that is being flared because it cannot be sold and is not easily reprocessed to produce on-spec product. Off-spec flaring may occur for some time during startup until the product is within specification.
>
> … There is growing concern that emissions of VOCs from flares may be much higher than previously thought. One possible reason is that wind effects can reduce flare destruction efficiency. The estimated emissions from flares are often based on measurements made with little or no wind. Accordingly, the emissions may be much higher under windy conditions.
>
> … Another very challenging problem is that weather conditions, the waste-gas flowrate, and composition are highly variable and not generally controllable. For example, wind plays a very significant role in the performance of a flare.[381]

Another study cited in the *Hydrocarbon Processing* article identifies wind speed as a major impact on flare efficiency, cites wind tunnel flare efficiencies well under 90% in certain wind conditions, and references an earlier study that found average flare efficiency of only 70%as a result of crosswind effects.[382] These reduced efficiencies would drastically increase flaring emissions compared to emissions using an assumed 98% or 99% destruction efficiency.

VI.G.2 BACT Is the Use of a Flare Gas Recovery System

The PDOC determines that BACT for criteria pollutant emissions from the Project's three flares is a flare gas recovery system for non-emergency releases.[383] Yet elsewhere, the PDOC eliminates flare gas recovery system as a BACT control option for GHG emissions as technically infeasible stating "[g]iven the extremely infrequent nature of events producing flared gases available for recovery and the lack of a

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[381] J. Peterson, Flint Hills Resources, Corpus Christi, Texas, N. Tuttle, H. Cooper and C. Baukal, John Zink Co., LLC, Tulsa, Oklahoma, Minimize Facility Flaring, Flares Are Safety Devices that Prevent the Release of Unburned Gases to Atmosphere, June 2007 issue, pp. 111-115; http://www.johnzink.com/wp-content/uploads/flare_hydro_proc_june_20071.pdf.

[382] P.E.G. Gogolek, A.C.S. Hayden, Performance of Flare Flames in a Crosswind With Nitrogen Dilution, Journal of Canadian Petroleum Technology, August 2004, Volume 43, No. 8, p. 1.

[383] PDOC, Appx. C, pp. C-21-C-30.

reasonably compatible outlet for recovered gases at the time of flaring events, flare gas recovery compression is judged not to be feasible for the HECA facility."[384] The PDOC's compliance conditions for flares appear not to require installation of a flare gas recovery system.[385] As the District correctly determined in its BACT determination for criteria pollutants, a flare gas recovery system is feasible and must be required as BACT. Further, the PDOC's BACT determination for criteria pollutants is deficient in that it only addresses non-emergency releases. A proper BACT analysis must also address emergency releases from the flares, establish BACT emission limits and identify the respective control technology.

VI.H BACT Determination for Fugitive Equipment Leaks Is Deficient

As discussed above, fugitive emissions from equipment leaks would occur from 21 process streams throughout several areas throughout the HECA Project. The PDOC recognizes that BACT is required for fugitive emissions from equipment leaks and presents a BACT analysis in Appendix C.

The PDOC analysis assigns the HECA Project's 21 process streams to three emission units as follows:

S-7616-21 gasification system: process streams #1, 2, 4 through 10 (there is no #3);
S-7616-23 sulfur recovery unit: process stream #11 through 12; and
S-7616-33 ammonia startup heater: process streams 13 through 21.[386]

The PDOC's BACT analysis of fugitive equipment leaks from these aggregated process streams is deeply flawed.

First, rather than identifying all control technologies (Step 1 in a five-step top-down BACT analysis), the District identifies its own BACT Guidelines 4.12.1 for Chemical Plants Valves & Connectors and 4.12.2 for Chemical Plants Pump and Compressor Seals[387] only to find later by circular foregone conclusion that those very same BACT Guidelines constitute BACT for the HECA Project. This approach defies the clear requirements of a BACT analysis for purposes of the Clean Air Act, as discussed in Comment VI.E above. Again, the PDOC again relies only on information contained in the outdated SJVAPCD BACT Guidelines. A top-down BACT analysis must first identify all control technologies, which in this case includes leakless technology (*e.g.*, welded connectors, bellows valves, double mechanical seals with high pressure fluids

[384] PDOC, Appx. I, p. 39.

[385] PDOC, Appx. A, pp. A-78-A-100.

[386] PDOC, p. 37.

[387] PDOC, Appx. C, p. C-13.

on pumps, enclosed distance pieces on compressors with venting to a control device, etc.) The PDOC's BACT analysis fails to identify and analyze the feasibility of leakless technology for the HECA Project's equipment components.

Second, the PDOC in Appendix C presents a BACT analysis only for fugitive VOC emissions associated with the gasification system (S-7616-21) and the sulfur recovery unit (S-7616-23).[388] The title of this "top-down" BACT analysis fails to include the fugitive emissions associated with the process streams assigned to the ammonia startup heater.[389]

Third, the PDOC's BACT analysis finds (by circular reasoning) that BACT for VOC emissions from equipment leaks for the gasification system and the sulfur recovery unit is implementation of a leak detection and repair ("LDAR") program described as "a leak defined as a reading of methane in excess of 100 ppmv above background for valves and connectors and in excess of 500 ppmv above background for pump and compressor seals when measure [sic] per EPA Method 21 and an Inspection and Maintenance Program pursuant to District Rule 4455."[390] Review of the determination of compliance conditions in Appendix A shows that the District implements the above BACT determinations only for select process streams assigned to the gasification unit and the ammonia startup heater, but not the sulfur recovery unit, specifically for streams #1 (methanol), #5 (propylene), #7 (H_2S-laden methanol), #8 (CO_2-laden methanol), #9 (acid gas), and #10 (ammonia-laden gas) which are associated with the gasification system[391] and streams #13 through #21 which are associated with the ammonia synthesis unit. Thus, BACT as determined by the District, is not required for four of the Project's process streams, specifically it is not required for process stream #4 (shifted syngas) and #6 (sour water), which are associated with the gasification unit as well as #11 (sulfur) and #12 (TGU process gas), which are associated with the sulfur recovery unit. This partial application of BACT appears to stem from the Applicant's proposal to only apply LDAR to select process streams which were selected "because they had the largest uncontrolled emission estimates for methanol, propylene, H_2S, and ammonia."[392] The PDOC contains neither a discussion of this selective application of BACT nor does it provide a table summarizing emissions from the various process streams or a threshold below which it deemed BACT not necessary. This turns the BACT determination on its head because it implements the Applicant's predetermined preferences into conditions that instead should instead be based on BACT.

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388 PDOC, Appx. C, pp. C-13-C-14.

389 *Ibid*.

390 PDOC, Appx. C, p. C-13.

391 PDOC, Appx. A, Condition 9, p. A-22.

392 PDOC, p. 37.

Finally, the PDOC's BACT analysis for fugitive emissions of GHGs is similarly flawed, again only identifying the District's BACT Guidelines as available technology and requiring BACT for select process streams only.[393]

VI.I The PDOC's BACT Determination for Greenhouse Gas Emissions for the Combined Cycle Power Generating System Is Deficient

The PDOC determines that BACT for GHG emissions from the HECA Project is 90% capture of pre-combustion CO_2 and sequestration and firing on hydrogen-rich fuel, energy-efficient turbine design, and firing on Public Utilities Commission ("PUC")-quality natural gas backup fuel limited to startups, shutdowns, and unplanned equipment outages.[394] There are a number of problems with this BACT determination.

First, while the PDOC's GHG BACT analysis on its face is organized according to the above discussed five-step top-down process recommended by EPA, it does not actually follow the process. Step 1 of the BACT determination requires identification of all possible GHG emission controls. The PDOC identifies 90% capture of pre-combustion CO_2 and sequestration and firing on hydrogen-rich fuel as one of the possible control options. It should also identify and evaluate 100% capture of pre-combustion CO_2 and sequestration. Step 3 of a BACT determination requires that all available control technologies be ranked in descending order of control-effectiveness. The BACT determination does not assign any control efficiency to the any of the remaining control technologies. Further, the PDOC does not contain an enforceable permit condition verifying that the Project achieves 90% capture of pre-combustion CO_2 and sequestration.

VII. THE PDOC DOES NOT ADEQUATELY LIMIT THE FACILITY'S POTENTIAL TO EMIT HAZARDOUS AIR POLLUTANTS TO LESS THAN THE MAJOR SOURCE THRESHOLDS

The HECA Project would operate equipment that would have the potential to emit HAPs. Emission points include the HRSG stack, coal dryer stack, cooling towers, auxiliary boiler, ammonia plant startup heater, emergency generators and fire water pump, three flares, thermal oxidizer for the sulfur recovery unit, CO_2 vent, manufacturing complex, and fugitive and AGR unit vent in the gasification block; the exhaust stack serving the combined cycle combustion turbines ("CCCTs") and heat recovery steam generator ("HRSG") in the power block; the natural gas-fired burners in the coal milling and drying system; the gasifier coal bunker vents; the natural gas-fired

[393] PDOC, Appx. I, pp. 52-54.

[394] PDOC, Appx. I, pp. 23-24.

auxiliary boiler and startup heater; the diesel-fueled fire pump and emergency generator engines; and fugitive equipment leaks.[395]

The PDOC finds that the HECA Project is a minor source of HAPs, thus attempting to exempt this facility from maximum achievable control technology ("MACT") emission limitations. There are two types of minor sources: (1) a "genuine minor source" is one in which the potential to emit is below the major source threshold; (2) a "synthetic minor" source is one with potential emissions in excess of major source emission thresholds except that enforceable limitations on the source's potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. As shown below, the PDOC violates the fundamental principles regarding the creation of minor source permits, including synthetic minors, as the Project's actual potential to emit exceeds the major source thresholds for HAPs and the PDOC's compliance conditions do not ensure that emissions of HAPs from this facility will remain under major source thresholds.

Since this facility unquestionably has the potential to emit HAPs in excess of major source HAP emission thresholds and the PDOC does not have enforceable limitations on the potential to emit that would ensure emissions remain below these thresholds, the District may not authorize construction of the HECA facility without issuing a MACT/NESHAP determination.

VII.A Background on the Regulation of Hazardous Air Pollutants

The Clean Air Act reserves its strictest controls for hazardous air pollutants – air toxics posing serious health effects (often carcinogenic or neurotoxic) even in relatively small quantities.[396] The regulatory regime controlling hazardous air pollutants (contained in Section 112 of the Act) reflects the enormity of those pollutants' health effects.[397] It also reflects Congress' frustration with state and federal agencies' persistent failures to properly regulate air toxics; Congress described past regulatory efforts as a "record of false starts and failed opportunities."[398] As a consequence of those congressional concerns[399], Section 112 of the Clean Air Act bears three distinguishing

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[395] *See* PDOC, Appx. H.

[396] *See* 42 U.S.C. § 7412(b)(1)-(2) (listing hazardous pollutants and instructing U.S. EPA (hereafter referred to as "EPA") to add additional substances "reasonably anticipated to be carcinogenic, mutagenic, teratogenic, neurotoxic, which cause reproductive dysfunction, or which are acutely or chronically toxic.").

[397] *See* S. Rep. No. 101-228, at 127 (1989), as reprinted in 1989 U.S.C.C.A.N. 3385, 3513-14 (noting that "ample margin of safety" might require "zero exposure to carcinogens, because any amount of exposure may cause a cancer").

[398] *Id*. at 3517.

[399] *Ibid*.

features: (1) extraordinarily strict limits, set by EPA; (2) direct, mandatory prohibitions that leave no room to avoid those limits; and, (3) express federal jurisdiction to address violations of those limits and prohibitions.[400]

The limits prescribed for hazardous air pollutants are those reflecting the "maximum achievable control technology" ("MACT"), defined as the "maximum degree of reduction in emissions…. that the Administrator [of the federal EPA] …. determines is achievable," considering costs, non-air quality health and environmental impacts, and energy requirements.[401] EPA sets MACT limits for categories of industrial facilities – often referred to as National Emission Standards for Hazardous Air Pollutants ("NESHAPs"); once set, they apply nation-wide to all major sources within those categories.[402] On March 28, 2013, after several challenges and revisions, EPA finalized nationwide MACT limits for new and existing coal and oil-fired electric generating units ("EGUs") in the so-called federal Mercury and Air Toxics ("MATS") rule.[403] (For a discussion of the Project's compliance with this rule, *see* Comment VII below.)

Unlike other similar limits in the Act, Congress added a "floor" to the MACT definition: MACT limits for new plants may "not be less stringent than the emission control that is achieved in practice by the best controlled similar source, as determined [EPA]."[404] That floor is the heart of the MACT limit, resulting in standards that are substantially stricter than those the Act requires elsewhere.[405]

For example, the "best available control technology" limits applicable to other regulated pollutants allow individual sources to plead excessive costs, or infeasibility, and thereby secure relaxed standards.[406] The MACT floor, in contrast, applies

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[400] *See id.* at 3513 (noting Congress' intent to "entirely restructure the existing law, so that toxics might be adequately regulated by the Federal Government").

[401] 42 U.S.C. § 7412(d)(2).

[402] 42 U.S.C. § 7412(d)(1). *See, e.g.,* 74 Fed. Reg. 21,136, 21,140-41 (May 6, 2009) (setting standards for portland cement manufacturing facilities).

[403] EPA, National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric UtilitySteam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial- Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; http://www.gpo.gov/fdsys/pkg/FR-2013-04-24/pdf/2013-07859.pdf.

[404] 42 U.S.C. 7412(d)(3). MACT limits for existing sources have a slightly relaxed floor; they may not be less stringent than the "best performing 12 percent of the existing sources." 42 U.S.C. § 7412(d)(3)(A).

[405] *See* 59 Fed. Reg. 15,504, 15,564 (May 10, 1994) ("[T]he MACT floor is a fundamental requirement of the section 112(g) determination.").

[406] 42 U.S.C. § 7479(3).

regardless of cost, or even a particular plant's ability to meet the resulting standard.[407] And MACT limits are required for every hazardous air pollutant emitted by a facility.[408]

Mindful of agencies' reluctance to impose restrictions that might be "potentially very costly for some [regulated industries],"[409] Congress gave the federal EPA, rather than states, the authority and obligation to set nation-wide MACT standards for major sources of hazardous air pollutants.[410] Congress further pre-empted state authority to set "any emission standard or limitation which is less stringent than" the standards required by Section 112.[411]

Under Clean Air Act Section 112(g), "no person may construct or reconstruct <u>any major source of hazardous air pollutants</u>, unless [EPA] (or the State) determines that the [MACT] emission limitation … for new sources will be met."[412] Accordingly, the first step in the section 112 process is to determine whether a facility is a "major" or "minor" source of hazardous air pollutants. A major source of HAPs is defined as a stationary source or group of stationary sources located in a contiguous area and under common ownership and control which have the potential to emit at least 10 tons/year of any single HAP or at least 25 tons/year of all HAPs in total.[413]

VII.B The PDOC Does Not Adequately Restrict Emissions of Hazardous Air Pollutants to Ensure Synthetic Minor Source Status

The PDOC finds that the proposed compliance conditions would limit the facility's HAP emissions to less than the applicable major source HAP emission thresholds of 25 tons per year in the aggregate for total HAPs and less than 10 tons per year for any single HAP, thereby defining the HECA Project as a synthetic minor source.[414] However, the record does not support these claims.

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[407] *Natural Res. Def. Council v. E.P.A.,* 489 F.3d 1364, 1376 (D.C. Cir. 2007) ("[C]ost is not a factor that EPA may permissibly consider in setting the MACT floor."); *Cement Kiln Recycling Coal. v. E.P.A.,* 255 F.3d 855, 866 (D.C. Cir. 2001) (rejecting MACT floor based upon sources' ability to achieve limits).

[408] 42 U.S.C. § 7412(a)(6); *Nat. Lime Ass'n v. E.P.A.*, 233 F.3d 625, 633-34, 640 (D.C. Cir. 2000) (noting "clear statutory obligation to set emissions for each listed [hazardous air pollutant]" and suggesting that Section 112 "does not provide for exceptions from emissions standards based on *de minimis* principles where a floor exists").

[409] 1989 U.S.C.C.A.N. at 3517.

[410] 42 U.S.C. § 7412(e).

[411] 42 U.S.C. § 7416.

[412] 42 U.S.C. § 7412(g)(2)(B) (<u>emphasis</u> added). See 40 C.F.R. § 63.42(c).

[413] *See* 40 C.F.R. § 63.41; SJVAPCD Rule4002; SJVAPCD Rule 2550 (implementing 40 CFR part 63.40 through 63.44).

[414] PDOC, pp. 146-147, and 175-176.

The District does not appear to have conducted independent emission calculations for the proposed HECA Project; instead, it appears to have relied entirely on the Applicant's estimates of potential HAP emissions contained in the Application, Appendix F, to come to its conclusion that the facility is not a major source of HAPs.[415] The PDOC simply reproduces the Applicant's summary table for HAP emissions from the Project's various emissions units in Appendix H and concludes that the HECA Project is not a major source for HAPs pursuant to SJVAPCD Rule 4002 and therefore not subject to provisions of SJVAPCD Rule 2550,[416] which implements preconstruction review requirements of 40 CFR part 63.40 through 63.44.

The phrase "potential to emit" for HAPS is substantially similar to the PSD regulations.[417] Comment V discussed the requirements for calculating PTE in the PSD regulations. This discussion is equally applicable for HAP emissions.

As discussed before, the PDOC fails to provide the respective underlying calculations and assumptions to support the summary table in Appendix H and fails to incorporate the Applicant's substantially revised emission estimates for HAPs contained in the 1/10/2013 HECA Updated Emissions Data. Review of the latter shows that the underlying calculations are based on severely flawed and not adequately supported emission estimates, fail to calculate maximum (worst-case) HAP emissions, and fail to account for all pollutants and emission sources. The PDOC then compounds these errors by failing to reflect the emission calculations in enforceable permit limits. When properly estimated, potential emissions of HAPs from the proposed facility by far exceed the major source thresholds for both individual and total HAPs, making the proposed facility a major stationary source of HAPs and requiring MACT for all applicable sources.

VII.C Assumptions Are Not Adequately Supported

The District does not provide a discussion of HAP emission estimates in the PDOC and appears to have accepted the Applicant's emission estimates wholesale. Yet many of the Applicant's emission estimates for HAPs rely on emission factors from emission testing at other facilities, vendor-supplied information, or other studies that were not made available for public review. Thus, a considerable portion of the Applicant's emission estimates for HAPs are unsupported in the record. The following information, used by the Applicant to develop emission estimates for the facility, is not or not adequately supported:

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415 PDOC, p. 146.

416 PDOC, pp. 146-147, and 175-176.

417 SJAPCD Rules 2520 & 2530.

- For example, as discussed before, the PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based the average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit and the fertilizer complex. These weight fractions are entirely unsupported.

- Uncontrolled coal dryer mercury emissions from volatilization estimated by MHI are not supported by a vendor guarantee.

- Assumed split between HRSG and coal dryer exhaust of 85%/15% is not supported.

- Mercury concentration in coal feed of 0.13 ppmw is not supported by feedstock analyses.

- Emission rates for the manufacturing complex are based on "reference plant information" with no support which plant the Applicant refers to nor a copy of source tests or any other supporting information.

- HAP emission factors for cooling towers using an average of analytical test results determined by Fruit Growers Laboratory are not supported by a copy of the test results or an explanation what type of facility was tested nor are specifications for the composition of the cooling tower water provided. No discussion is provided why the results of this test are assumed applicable to the HECA Project's cooling towers.

- CO_2 vent gas methanol concentrations are based on process licensor data with no vendor guarantee or other explanation.

In *In re Steel Dynamics, Inc.*, the Environmental Appeals Board remanded the permit back to the state agency after finding that the state agency's PTE evaluation was inadequate because the agency did not include explanations of the underlying basis for its calculations and the public record contained no documents supporting its conclusion.[418] Without this information, the Board determined that it was unable to determine whether or not the significance level for a given pollutant would be exceeded and, thus, whether BACT for lead should be installed at this facility. Moreover, the Board remanded the permit back to the state agency because it failed to consider detailed comments regarding an alternative calculation for potential to emit submitted by a commenter. The comments had articulated how the agency had underestimated the facility's emissions of lead and other hazardous air pollutants, erroneously failed to

[418] 9 E.A.D. 165, PSD Appeal Nos. 99-4 & 99-5, 2000 WL 833062 (June 22, 2000).

consider all potential sources of lead emissions, and finally presented its own calculated PTE after correcting for these deficiencies.

This PDOC is similar to the Steel Dynamics permit as the District's potential to emit evaluation for HAPs is inadequate, cursory, and not supported by documents in the record. Sierra Club addresses some of these deficiencies below.

VII.D The PDOC Underestimates the Facility's Potential to Emit for HAPs and Compliance Conditions Are Inadequate to Enforce the Synthetic Minor Source Status

As explained in the comments below, the emission calculations the PDOC relied upon to make its determination that the facility would be a minor source of HAP emissions are flawed and result in substantially underestimated emissions. Further, the PDOC's compliance conditions are not enforceable and identify the Project as a major source of HAP emissions because the emission limit for COS, a HAP, exceeds the 10 ton/year threshold triggering major source status for individual HAPs.

VII.D.1 Emissions from Flares Do Not Account for Unplanned Events and Rely on Inappropriate Emission Factors

Flares emit HAPs and TACs during both routine and non-routine operations from three sources: (1) pilot; (2) supplementary natural gas fuel; and (3) syngas and waste gases. The Applicant's estimates for HAP emissions from the three flares shows that only emissions from operation of the natural gas-fired pilots and during startup/shutdown are accounted for.[419] The Applicant did not discuss the use of HAP emission factors for flaring shifted and unshifted syngas, which may result in considerably higher emissions of HAPs than combustion of natural gas, nor did the Applicant make an attempt to estimate HAP emissions for unplanned malfunction (upset) events. As discussed in Comment VII.B above, emissions from unplanned events must be included in the potential to emit calculations.

Further, the Applicant' estimates emissions of HAPs from flares during pilot operation and gasifier startup/shutdown are based on emission factors from AP-42, Chapter 1.4, for natural gas-fired boilers.[420] This assumes the behavior of a flare from a combustion standpoint is similar to a natural gas fired boiler, which is not the case. A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. In contrast, a flare has no combustion chamber and highly variable gas

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[419] *See* 1/10/2012 HECA Updated Emissions Data, "Gasification Flare – HAP Emissions Summary", p. 6 of 25, pdf 127; "SRU Flare – HAP Emissions Summary", p. 7 of 25, pdf 128; "Rectisol Flare – HAP Emissions Summary", p. 8 of 25, pdf 129.

[420] 1/10/2013 HECA Updated Emissions Data, footnote to tables "Gasification Flare," SRU Flare," and "Rectisol Flare," pp. 6-8 of 25, pdf 127-129.

flow and composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler. Further, the flares would combust syngas and waste gases which have a different composition than natural gas.

Sierra Club requested an explanation from the Applicant why it deemed emission factors from natural gas combustion in boilers representative for combustion of natural gas, syngas and waste gases in the Project's flares for both normal operating emissions from the pilot and during gasifier and Rectisol startup and shutdown. The Applicant responded that "Because the United States Environmental Protection Agency (U.S. EPA) has not published emissions factors for hazardous air pollutants (HAPs) from flares, the emission factors for HAPs from natural gas combustion in boilers have been used. During normal operation of the pilot, natural gas is being combusted—the same fuel represented in the emission factors. During start up and shut down of the gasifier and Rectisol flares, syngas is being burned, which is composed primarily of hydrogen. In this case, the applied emission factors are an overestimate of HAPs from flare combustion. Therefore, the emission factors used are appropriate and conservative."[421] This explanation is entirely unsatisfactory as it does not address the question why combustion in a flare may be assumed to be equivalent to combustion in a boiler nor does it adequately address the different composition vs. natural gas and syngas and waste gases. Neither the District nor the Applicant made any attempt to identify emission factors for flares. The District must identify appropriate worst-case HAP emission factors based on the composition of the various gas streams that may be routed to the flares.

VII.D.2 Emissions from the CO_2 Vent Are Underestimated, Emission Limits Are Incorrect, Establish the Project as a Major Source, and Are Not Adequately Enforced

The PDOC presents emission estimates for HAPs from the CO_2 vent for only two pollutants, H_2S and COS.[422] The Applicant revised its emission estimates for HAPs to include methanol emissions in the vent gas stream, which originates in the Rectisol unit. Further, the CO_2 vent stream may contain other HAPs including SO_2 which converts to SO_3 and sulfuric acid mist ("SAM"), a hazardous air pollutant. The PDOC must be revised to include all pollutants in its potential to emit for HAPs.

Further, for purposes of determining potential to emit for criteria pollutant, the PDOC estimates maximum annual VOC (methanol), H_2S, and COS emissions from the CO_2 vent assuming 21 days/year (equivalent to cumulative 504 hours/year) of venting

[421] HECA Response to Sierra Club Data Request No. 59, October 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-10-03_Applicants_Responses_to_Sierra_Club_Data_Requests_Numbers_1_through_97_TN-67515.pdf.

[422] PDOC, Appx. H.

at the full vent flow capacity (17,584 lb-mol/hour at 100%) and maximum concentrations of methanol, COS, and H_2S in the vent gas of 40 ppm, 10 ppm, and 10 ppm, respectively.[423] These assumptions result in emissions of 2.84 tons/year methanol[424], 1.51 tons/year H_2S, and 2.66 tons/year COS.[425] (As discussed in Comment V.B.3, the PDOC incorrectly calculates VOC emissions based on the molecular weight of methane (16 lb/lb-mol) instead of methanol (32 lb/lb-mol), thereby underestimating VOC (methanol) emissions by a factor of two.)

The PDOC does not provide detailed corresponding detailed emission calculations for HAP emission. However, review of the 1/10/2013 HECA Updated Emissions Data shows that for purposes of estimating HAP emission from the CO_2 vent, the Applicant relies on a far less conservative approach than described above for criteria pollutants, assuming an expected "average" vent flow at a reduced capacity of only 85%, and a lower "typical" long-term methanol concentration in the vent gas of 20 ppm.[426] This approach reduces the Applicant's emission estimates to 2.41 tons/year methanol, 1.28 tons/year of H_2S and 2.26 tons/year COS. Unless the PDOC includes enforceable permit conditions to ensure compliance with its estimates, which it does not, it must assume "maximum potential" emissions for all pollutants including HAPs.

By using this approach (and correctly assuming the molecular weight of methanol), the Applicant lowered total estimated facility methanol emissions – 9.83 tons/year – to just below the 10 tons/year threshold for emissions of individual HAPs that would trigger major source status. Revised emissions correcting for 100% vent flow capacity, concentrations in the vent stream of 40 ppm methanol, and the molecular weight of methanol and otherwise relying on the Applicant's assumptions can be estimated at 5.68 tons/year methanol.[427] When added to the fugitive methanol emissions from equipment leaks of 7.29 tons/year[428], this results in total annual facility methanol emissions of 13.09 tons/year, 30% above the major source threshold for individual HAPs.

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[423] PDOC, pp. 54, 81, and 93; *see* also, 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

[424] The PDOC calculates 5,672 lb/year on a methane basis and converts this estimate incorrectly to 2.34 tons/year instead of 2.84 tons/year.

[425] *See* PDOC, p. 81, for H_2S; COS = (504 hours/year)(17,584 lb-mol/hr)(60 lb/lb-mol COS)(10 ppm) = 5,324 lb/year = 2.66 tons/year.

[426] 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

[427] MeOH = (504 hours/year)(17,584 lb-mol/hr)(32 lb/lb-mol COS)(40 ppm) = 11,358 lb/year = 5.68 tons/year.

[428] 1/10/2013 HECA Updated Emissions Data, "Intermittent CO_2 Vent – HAP Emissions Summary," p. 10 of 25, pdf 131.

Further, the PDOC contains compliance conditions limiting emissions of COS from the CO_2 vent to 58.0 lbs/day, 14.62 tons/year, and 55 ppm.[429] These emission limits are inconsistent with the Applicant's assumptions for the concentration of this pollutant in the CO_2 vent stream of 10 ppm. Further, the emissions limit of 14.62 tons/year COS is inconsistent with the PDOC's determination that the HECA Project would not be a major stationary source of HAPs because COS is a HAP and the proposed emission limit is greater than the threshold of 10 tons/year for individual HAP emissions per District Rule 4002. Finally, revising the Applicant's emission estimates based on the District's permit condition for COS results in total HAP emissions from the facility of 30.94 tons/year, far in excess of the 25 tons/year major source threshold.[430] Thus, based on the PDOC's emission limits and conditions of compliance, the Project is a major source of HAPs.

VII.D.3 Fugitive Equipment Leaks Are Not Adequately Supported and Are Underestimated

As discussed before, the PDOC relies on the Applicant's calculation of fugitive emissions from equipment leaks which is based an entirely unsupported average weight fraction of total organic compounds ("TOC") in various process streams throughout the gasification unit and the fertilizer complex.[431] As demonstrated above, even a minor variation in these assumptions could turn the Project in a major source of HAPs.

VII.D.4 Emissions from the HRSG and Coal Dryer Are Not Supported and Potential to Emit for HAPs Is Underestimated

As discussed in Comments II.A and IV.B.2, emission estimates for the HRSG and coal dryer are not adequately supported and rely on a number of assumptions that underestimate the facility's true potential to emit. The same problems were carried over into the Applicant's estimates of HAP emissions for these units. In addition, the HAP emission estimates for these units suffer from a number of other flaws.

The Applicant estimates HAP emissions from the HRSG and coal dryer based on emission factors from test data determined at the Wabash River PSI Energy's Wabash River Generating Station in Indiana and a 2002 report by the DOE's National Energy

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[429] PDOC, Appx. A, Compliance condition Nos. 8, 9, and 11 for CO_2 Recovery and Vent System (S-7616-24-0), pp. A-42 - A-43.

[430] 1/10/2013 HECA Updated Emissions Data, "Emissions Summary" dated December 20, 2012, p. 1 of 25, pdf 122: (19.12 tons/year total HAPs) – (2.80 tons/year COS) + (14.62 tons/year COS) = 30.94 tons/year total HAPs.

[431] 1/10/2013 HECA Updated Emissions Data, *see* note above table "Area Speciation" in "Fugitive Emissions – Gasification Unit," p. 19 of 25, pdf 140.

Technology Laboratory ("NETL")[432] which summarizes source test data from several gasification facilities.[433] Elsewhere, the Applicant claims that "All emission factors were based Wabash River test data … with the exception of ammonia, mercury, and sulfur/sulfuric acid…" for which it provided separate emission estimates.[434] Yet, comparison of the Applicant's emission estimates for the HRSG and coal dryer with the Wabash River test data and the 2002 DOE/NETL report shows that several other emission factors used by the Applicant to estimate HAP emissions are not consistent with than those in the referenced sources, as summarized in the inset table below.

Table 5: Discrepancies between emission factors relied upon by 2012 ATC/PSD Application and Wabash River test data and 2002 DOE/NETL Report

Pollutant	**2002 DOE/NETL report** (lb/10^{12} Btu)	**2012 ATC/PSD Application** (lb/10^{12} Btu)	**Discrepancy** (lb/10^{12} Btu)
Antimony	4	1.1	2.90
Benzene	4.4	2.4	2.00
Chromium	2.7	0.51	2.19
Cobalt	0.57	0.26	0.31
Lead	2.9	0.56	2.06
Manganese	3.1	1.0	2.1
Nickel	3.9	0.39	3.51
Selenium	2.9	0.56	2.34

The Applicant provides no discussion of these discrepancies. Further, the 2002 DOE/NETL Report provides emission factors for a number of HAPs that are not incorporated into the Applicant's emission estimates. These include emission factors for benzaldehyde, benzo(e)pyrene, benzo(g,h,i)perylene, 2-methylnaphthalene.

Further, many of the emission factors assumed by the Applicant as representative for the HECA Project are "average" emission factors determined from a limited number of source tests. As such, they do not adequately represent the facility's maximum potential to emit as required under the Clean Air Act and SJAPCD Rules.

VII.D.1 Compliance Conditions Are Not Enforceable

The PDOC includes several compliance conditions requiring HECA to demonstrate that the Project would be a minor source for HAPs. However, these

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432 DOE, Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report, December 2002, hereafter "2002 DOE/NETL Report"; http://www.netl.doe.gov/technologies/coalpower/gasification/pubs/pdf/final%20env.pdf.

433 *See* Note 2 to 1/10/2013 HECA Updated Emissions Data, "HRSG and Coal Dryer Stack – HAP Emissions Summary" dated December 20, 2012, p. 2 of 26, pdf 123.

434 HECA Response to Sierra Club Data Request No. 38.t, November 2012; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-05_Applicant_Responses_to_Sierra%20Club_Data_Requests_1-97_TN-68378.pdf.

conditions fall short of demonstrating compliance and fail to specify remedies in case it were discovered that the Project is not a minor source of HAPs.

First, the PDOC requires an <u>initial</u> speciated HAP and total VOC source test for the CO_2 recovery and vent system to determine the total HAPs emission rate, the single highest HAP emission rate and the VOC mass emission rate.[435] This condition does not address the variability of the gas stream that would be vented during the source test event. Vent gas composition will vary depending on the operating conditions of the facility at the time of venting, the fuel blend, the capacity at which the syngas scrubber, gas cooling, mercury removal, and acid gas removal units, etc., are functioning, and so forth. For example, under normal operating conditions, the gas stream from the sulfur recovery unit will be treated in the tail gas treating unit and then transported to the CO_2 vent system for custody transfer. However, in the event of any unscheduled tail gas treatment curtailment or operating problems, the sulfur recovery unit tail gas can be redirected into the CO_2 product stream.[436] A single speciated source test will therefore not capture the variability of HAP concentrations in the vent gas stream (*e.g.*, methanol concentrations in the vent stream will vary widely depending on the operating conditions in the Rectisol unit).

In addition, the same condition of compliance requires that HECA demonstrate <u>initial</u> compliance with the HAPs emission limits (25 tons/year all HAPs or 10 tons/year any single HAP). The PDOC fails to lay out a formula and specify emission rates from other emission sources to ensure that the Applicant's emission calculations include emissions from the entire stationary source instead of comparing only the CO_2 vent emissions to these emission limits.

The compliance conditions also require that HECA demonstrate <u>ongoing</u> compliance based on the vent stream composition of CO, VOC, H_2S, COS, and HAPs identified during the initial source test and determined using mass flow and VOC sampling during venting occurrences exceeding 500,000 scf/day using EPA-approved test methods with a gas chromatograph or equivalent equipment as determined by the District. The PDOC does not provide a discussion of how the cutoff vent flow of 500,00 scf/day was determined during which the Applicant must measure the vent stream composition nor does it discuss why the vent gas composition cannot be monitored continuously.

[435] PDOC, Appx. A, Condition of Compliance No. 16, p. A-43.

[436] PDOC, Appx. C, p. C-16.

VII.E The PDOC Fails to Demonstrate Compliance with the National Emission Standards for Hazardous Air Pollutants for Electric Generating Units

On March 28, 2013, the EPA finalized the federal Mercury and Air Toxics ("MATS") rule for electric generating units ("EGUs"). The MATS rule establishes emission limits for new IGCCs at 0.07 lb/MWh (gross) on syngas and 0.09 lb/MWh (gross) on natural gas for particulate matter, 0.002 lb/MWh (gross) for hydrogen chloride, and 0.003 pounds per Gigawatt-hour ("lb/GWh") (gross) for mercury.

The PDOC does not provide a quantitative analysis demonstrating the HECA Project's compliance with the MATS rule and instead provides only the following brief summary discussing potential mercury emissions:

> In order to minimize potential mercury emissions, this project has incorporated mercury capture technology. Tests of petcoke sources show occasional trace levels of mercury in the elemental analyses. Western sub-bituminous coals typically contain trace levels of mercury as well. Mercury is removed downstream of the sour shift and low-temperature gas cooling (LTGC) units, and at the feedstock dryer using activated carbon. After mercury removal, the product syngas is treated in the acid gas removal (AGR) unit. These controls will reduce mercury emissions to a level that will comply with the new National Emission Standards for Hazardous Air Pollutants (NESHAP) for IGCC Electric Generating Units.[437]

This discussion is inadequate. First, the PDOC does not provide any documentation or emission estimates to back up its claim that HECA's mercury emissions would actually remain below the 0.03 lb/GWh (gross) emission limit established in the MATS rule nor does it identify the applicable MATS emission limit. Second, the PDOC does not require monitoring pursuant to MATS; thus its claim that HECA's mercury emissions would comply with the MATS standard is meaningless.

Review of emission calculation provided by the Applicant in the AFC proceeding before the CEC shows that the PDOC's claim regarding MATS compliance is not supported. The Applicant estimated maximum annual mercury emissions from the facility based on firing 100% coal from the El Segundo mine in New Mexico with a typical mercury content (dry basis) of 0.13 ppmw, a gasifier coal feed of 5,023 tons/day (dry basis), 85% diversion of exhaust flow to feedstock dryer, 75% feedstock dryer removal efficiency, and a >99% removal efficiency for the syngas mercury adsorber bed. These assumptions result in a mercury emission rate for the HECA Project of

[437] PDOC, p. 10.

0.00288 lb/GWh (gross), merely 0.00012 lb/GWh (gross) lower than the MATS standard.[438]

The slightest variability in the Applicant's assumptions could result in the estimated emission rate exceeding the MATS standard. For example, coal from the El Segundo mine shows large variability in mercury content with a maximum of 0.25 ppmw (dry basis).[439] The PDOC contains neither a restriction on the mercury content in the feedstock nor on the origin of the coal. Thus, depending on which area of the mine is extracted, the coal feedstock for the HECA Project could have a considerably higher mercury content than the typical mercury content of 0.13 ppmw assumed by the Applicant. Assuming a mercury content of 0.144 ppmw or higher and otherwise relying on the Applicant's assumptions would result in a mercury emission rate in excess of the MATS standard for mercury of 0.003 lb/GWh. This example illustrates the uncertainty associated with the Applicant's calculations and casts doubt on the facility's ability to comply with the MATS standard for mercury.

Further, it appears that the manufacturer of the mercury activated carbon adsorber beds guarantees the removal efficiency only for a mercury inlet concentration of 20 micrograms per normal cubic meter ("$\mu g/Nm^3$").[440] At the higher mercury inlet concentrations of up to 43 $\mu g/Nm^3$") expected by the Applicant's engineering firm Fluor for off-design conditions, the manufacturer of the mercury adsorber beds only "expects" a >99% removal efficiency but does not appear to provide a guarantee.[441] Thus, depending on the circumstances of these off-design conditions, mercury

[438] *See* HECA Response to Sierra Club Data Request No. 145, February 2013; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[439] *See* Attachment B (APS/Pacific Corp Fuel Contracts Excerpts: Typical Analysis for El Segundo) to Conrad Spencer, APS, Cholla Steam Electric Station, Letter to Trevor Baggiore, Arizona Department of Environmental Quality, Re: Request for Additional Information for BART Analysis of Cholla Units 2, 3, and 4, June 18, 2009; http://www.azdeq.gov/environ/air/haze/download/110810g.pdf.

[440] Patrick Flanagan, Norit Americas, Inc., Email to Jim Loney, Fluor, Re: Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, February 7, 2013; provided by HECA in response to Sierra Club Data Request No.144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

[441] Patrick Flanagan, Norit Americas, Inc., Email to Robert Gross, Fluor, Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, January 25, 2013; provided by HECA in response to Sierra Club Data Request No. 144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

emissions from the HECA Project could be considerably higher than calculated, particularly during the commissioning period, exceeding the MATS standard.

Sierra Club recommends that the District scrutinize the Applicant's other assumptions for calculations of mercury emissions from the HECA Project. The revised PDOC should heed the EPA's recommendations in its comments on the PDOC for the prior HECA application (08-AFC-8). Specifically, for those sources where emission estimates and/or emission limits were relatively close to a threshold, the EPA recommended "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."[442] Further, the revised PDOC should take care to only include the significant figures warranted by the input parameters for the calculation.

Lack of Adequate Compliance Conditions to Demonstrate Compliance with the MATS Standard

In order to demonstrate compliance with the calculated emission rates for the HECA Project as calculated by the Applicant and relied upon by the District to find that mercury emissions would comply with the MATS standards (*see* Comment VII), Sierra Club recommends that the District revise the PDOC to include enforceable permit conditions restricting the feedstock mercury content, gasifier feed rate, etc.

Further, the PDOC's assumption that mercury emissions would be below the MATS standard rely on the Applicant's calculations which assume a 99% removal efficiency of the mercury adsorber beds in the mercury removal unit. The manufacturer of these mercury adsorber beds provides a conditional guarantee:

> Norit RBHG 3 is conditionally guaranteed to achieve >99% removal of mercury for three years. The performance guarantee is based on a minimum bed residence time of 10 seconds at a velocity of less than 60 fpm. Operating conditions for the system must not exceed 60 degrees C, and must have less than or equal to 20 micrograms/Nm3 mercury concentration at the inlet of the carbon adsorber.[443]

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[442] Gerardo Rios, EPA, Letter to David Warner, SJVAPCD, Re: EPA Comments on Project Number S-1093741 (08-AFC-8), August 16, 2010; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/08-AFC-8/others/2010-08-16_EPA_Comments_TN-58112.pdf.

[443] Patrick Flanagan, Norit Americas, Inc., Email to Jim Loney, Fluor, Re: Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, February 7, 2013; provided by HECA in response to Sierra Club Data Request #144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

Thus, the PDOC must incorporate monitoring provisions to guarantee the above specified operating conditions to ensure that HECA's mercury emissions are indeed below the MATS standard of 0.003 lb/GWh as calculated. While the manufacturer "expects" that the adsorber bed would still provide a >99% efficiency at higher mercury concentrations of up to 43 $\mu g/Nm^3$ during off-design conditions, the guarantee is restricted to 20 $\mu g/Nm^3$.[444]

Sierra Club further recommends that facility demonstrate compliance with mercury limits via source stack testing and using a continuous emissions monitor ("CEMS") for particulate matter rather than only periodic source testing for particulate matter as proposed by the Applicant.[445]

VII.F Summary

As discussed above, the PDOC's compliance conditions identify the Project as a major source of HAPs. Even if the respective condition is revised to correspond with the Applicant's revised emission estimates, the PDOC (by wholesale accepting the Applicant's emission calculations) failed to account for the full potential to emit for HAPs because it failed to account for all emission sources and pollutants and did not rely on conservative assumptions. When these errors corrected, emission estimates exceed the trigger thresholds of 10 tons/year for individual HAPs and likely the trigger threshold of 25 tons/year for total HAPs. Therefore, the facility is a major source of HAP emissions requiring toxics BACT ("T- BACT").

VIII. THE PDOC'S AMBIENT AIR QUALITY IMPACT MODELING AND HEALTH RISK ASSESSMENT REPORT IS FLAWED

The PDOC presents an ambient air quality impact modeling and health risk assessment report for the HECA Project in Appendix K. This AAQI/HRA report is not adequately supported and is flawed.

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444 Patrick Flanagan, Norit Americas, Inc., Email to Robert Gross, Fluor, Re: Performance Guarantee Statement Required for RBGH3 Fluor Hg Removal Project, January 25, 2013; provided by HECA in response to Sierra Club Data Request #144, Attachment 144-3; http://energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

445 HECA Response to Sierra Club Data Request #146, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2013-02-15_Applicant_Responses_to_Intervenor_Sierra_Club_Data_Requests_Set_Three-Nos_132_through_146_TN-69562.pdf.

VIII.A Lack of Support

The AAQI/HRA Report describes emission scenarios and summarizes source stack parameters[446] but fails to quantify the emission rates from the respective sources that were modeled. As discussed in Comment VII.B, the emission rates summarized by the PDOC in Appendix H are outdated and are lower than the revised estimates provided by the Applicant to the CEC and Sierra Club on January 10, 2013. It is unclear which emission rates the PDOC's modeling relies upon. Thus, the results of the ambient air quality modeling and the PDOC's conclusion that HECA Project emissions would not result in significant health impacts are not adequately supported.

As discussed in Comments V & VII, the PDOC did not account for worst-case, or maximum, emissions from the HECA Project because, for example, it did not account for malfunction emissions and underestimated criteria pollutant and HAP emissions from a number of sources, including the CO_2 vent, fugitive equipment leaks. These errors were likely carried over into the modeling for the AAQI/HRA Report. Therefore, the results of the PDOC's AAQI/HRA Report with respect to the HECA Project's air quality and health impacts cannot be relied upon.

VIII.B NO_2/NOx In-stack Ratio for Heat Recovery Steam Generator

Despite the lack of any actual data for turbines burning hydrogen-rich gas, the PDOC assumes a NO_2/NOx in-stack ratio lower than the EPA-recommended default value of 0.5 that can be used without further justification. The PDOC states that "HECA proposes to use the conservative NO_2/NOx in-stack ratio of 0.3 for all turbine and dryer operating conditions" based on "professional engineering estimate" from the turbine and oxidation catalyst vendors.[447] Yet for purposes of modeling NO_2 concentrations, the PDOC specifies an even lower NO_2/NOx in-stack ratio of 0.2 for the HRSG.[448] The PDOC provides no explanation of why it assumed and modeled a lower in-stack NO_2/NOx ratio than proposed by HECA and estimated by the equipment vendors. The HRSG is the largest source of the Project's operational NOx emissions and the modeled concentrations of 1-hour NO_2 concentrations including the background (325 $\mu g/m^3$) are very close to the 1-hour CAAQS (339 $\mu g/m^3$).[449] Thus, an increase in the NO_2/NOx in-stack ratio could result in exceedances of the 1-hour CAAQS for NO_2. The District must assume the most conservative NO_2/NOx ratio for modeling purposes.

[446] PDOC, pp. 18, 42, and 56.

[447] PDOC, Appx. K, p. 47.

[448] PDOC, Appx. K, Table 8-4, p. 47.

[449] PDOC, Appx. K, Table 8-5, p. 49.

VIII.C Startup Emissions Are Not Modeled

EPA presently provides no exemption from complying with NAAQS during periods of (1) testing/maintenance or actual emergency operation, and (2) startup. From our review of the modeling files, it appears that the Applicant did not model peak one-hour startup, shutdown, and emergency related NO_2 and SO_2 emissions from all the sources.

VIII.D The PDOC's Finding that 24-hour PM10 Impacts Are Less than the Significant Impact Level Is Based on Flawed Emission Rate Calculations and Inappropriate Model Inputs

Sierra Club previously submitted comments regarding the HECA Project's modeled 24-hour PM10 impacts to the District and the CEC.[450] Below, we revise and expand our earlier comments to include our modeling results, including the actual emissions tables, modeling methodology and results:

The PDOC finds that the 24-hour PM10 impacts from the proposed HECA project will be 4.90 $\mu g/m^3$.[451] This impact represents 98% of the 24-hour PM10 significant impact level ("SIL"), which is 5.0 $\mu g/m^3$. Had the HECA Project impacts exceeded the SIL, then extensive modeling analyses would have been required to verify whether project emissions, in conjunction with surrounding emission sources, will lead to violations of the applicable PM10 PSD increments and NAAQS.[452] Since the PDOC does not identify HECA PM10 impacts above the SIL, these additional modeling analyses were not performed.

The PDOC's finding of less than significant PM10 impacts is based on flawed emission rate calculations, as discussed in Comment V, and inappropriate AERMOD model inputs, as discussed below. These flawed emission rate calculations and model inputs lead to under-predicted modeled impacts and incorrect findings of insignificance. When corrected, the 24-hour PM10 impacts from the proposed HECA Project will exceed the respective SIL and will violate applicable regulatory design concentrations. In particular, the 24-hour PM10 PSD increment of 30 $\mu g/m^3$ and the 50 $\mu g/m^3$ 24-hour PM10 CAAQS are sensitive standards that will be violated when corrected emission rates are used for modeling.

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[450] Andrea Issod, Sierra Club, Letter to Dave Warner, SJVAPCD, and Robert Worl, CEC, Re: Preliminary PM Modeling Comments on the PDOC for the HECA Project (08-AFC-08A), April 26, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-26_Sierra_Club_Comments_on_PDOC_TN-70503.pdf.

[451] PDOC, Appx. K, p. 49.

[452] SJVAPCD Rule 2410 and PDOC, Appx. K, p. 8.

In addition, the San Joaquin Valley already experiences very high PM10 levels, which are very close to putting the region back into nonattainment status for this pollutant. The PM10 impacts from the HECA Project only add to this concern and could jeopardize the current PM10 attainment status in the southern San Joaquin Valley. It is essential that the PDOC include a complete and proper analysis of HECA PM10 impacts. The 24-hour PM10 emission rates must be corrected and completely reassessed with updated modeling analyses in the PDOC.

VIII.D.1 The PDOC Underestimates 24-hour PM10 Impacts Because It Uses Inappropriate Paved Road Emission Calculations

HECA modeled fugitive dust PM10 emissions from onsite paved roads.[453] These emission sources often cause the highest modeled impacts from an industrial source, due to the low-level and non-buoyant nature of how they are released to the air. The paved road PM10 emissions calculated by HECA, however, use incorrect inputs, as discussed in Comment V.B.9.a above, resulting in substantially under-predicted emission rates and subsequent modeled impacts. These shortcomings are then carried over into the SJVAPCD's PDOC's modeling.

Revised Emission Rates

We revised the emission rates for on-site paved roads using very conservative assumptions:

- We recalculated the paved road fugitive PM10 emissions from Operation & Maintenance vehicles, Product Trucks, Coal/Coke Feedstock Trucks, and Miscellaneous Delivery Trucks using a conservatively low silt loading rate of 1.6 g/m^2. This results in an emission increase for these sources of a factor of 36.1918.
- We recalculated the paved road fugitive PM10 emissions from Product Trucks, Coke Feedstock Trucks, and Miscellaneous Delivery Trucks using an unloaded truck weight of 20 tons. This results in an emission increase for these sources of a factor of 1.8803.
- We recalculated the 24-hour paved road fugitive PM10 emissions from all onsite vehicles using no rainfall correction. This results in an emission increase for these sources of a factor of 1.0253.

The corrected 24-hour paved road fugitive PM10 emissions from all onsite vehicles are shown in the table below. These emission rates include combustion PM10 emissions as calculated and modeled by the Applicant.

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453 Paved road fugitive dust PM10 emissions were added to onsite vehicle combustion PM10 emissions.

Table 6a: PM10 Emissions from all Onsite Vehicles

Emission Source (modeled as volume sources)	**Applicant PM10 Emissions** (g/s)	**Corrected PM10 Emissions** (g/s)
Product Trucks (modeled as PTRK1 – PTRK73)	4.7117E-05	2.7538E-03
Coal/Coke Trucks (modeled as CTRK1 – CTRK34)	1.6417E-05	9.5952E-04
Misc. HHDT Delivery Trucks (modeled as MISCTRK1 – MISCTRK5)	6.1158E-04	1.5859E-03
Onsite O&M Trucks (modeled as OMTRK1 – OMTRK10)	2.1722E-04	3.0393E-03

VIII.D.2 The PDOC Underestimates 24-hour PM10 Impacts Because It Uses Inappropriate AERMOD Model Inputs

In addition to the under-estimated PM10 emission rates discussed above, the PDOC also uses flawed modeling methods to predict 24-hour PM10 ambient air concentrations. These model inputs are:

- The PDOC modeling uses ground-level receptors, rather than a flagpole height of 1.5 meters for human inhalation.
- The PDOC modeling uses Bakersfield airport meteorological data processed with outdated methods.

Each of these inappropriate model inputs are discussed below.

Flagpole Receptors

Receptors are locations where the AERMOD dispersion model calculates ambient air concentrations. These receptors are designated by the model user and include the geographical coordinate of the receptor, the elevation above sea level of the receptor, and the receptor height above the ground (known as flagpole height).

The PDOC modeling does not incorporate a receptor flagpole height, which results in the model calculating air concentrations at the surface of the ground. Since the HECA property boundary is less than a few hundred meters from their emission sources, a flagpole receptor height of about 1.5 meters should have been included in the PDOC modeling.[454] This corresponds to an average breathing zone of a person and will provide a better estimate of project-caused air impacts.

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[454] California Environmental Protection Agency, Air Toxics Hot Spots Program Risk Assessment Guidelines, Technical Support Document for Exposure Assessment and Stochastic Analysis, August 2012, p. 2-19; http://www.oehha.ca.gov/air/hot_spots/pdf/2012tsd/TSDportfolio2012.pdf.

Meteorological Data

The PDOC modeling uses 2006 through 2010 Automated Surface Observation Station ("ASOS") meteorological data collected at Meadows Field Airport, in Bakersfield. These ASOS data, however, are based on a single two-minute observation near the end of each hour and are not representative of a valid hourly-average. Furthermore, the meteorological data used in the PDOC modeling include over 27% calm hours, which are unusable by AERMOD. This large percentage of calm hours is a simple artifact of the standard ASOS reporting methods. Overstating the number of calm hours tends to result in under-predicted modeled impacts since the low wind speed conditions often associated with peak impacts are artificially excluded from the modeling analysis.

EPA has been aware of this issue for several years, and on February 28, 2011, EPA finalized a revised version of AERMET, along with a pre-processor program called AERMINUTE.[455] AERMET is the program that creates the meteorological data sets used by AERMOD. The revised version of AERMET (including AERMINUTE), can process one-minute airport data, thus correcting the reporting artifact that causes an unrealistically high number of calm hours in the data sets. EPA, state, and local air agencies now routinely use the revised AERMET and AERMINUTE programs for modeling compliance with ambient air quality standards. In their modeling guidance for SO_2 NAAQS designations, EPA discussed the concern of calm hours in underestimating air impacts:

> In AERMOD, concentrations are not calculated for variable wind (*i.e.*, missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO_2 NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.[456]

At the 10th Conference on Air Quality Modeling, held in March 2012, EPA stated that the purpose of the revised AERMET and AERMINUTE programs is "not to

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455 EPA, Addendum, User's Guide for the AERMOD meteorological Processor (AERMET), EPA-454/B-03-002, November 2004, (v. 12345, released publicly in December 2012). http://www.epa.gov/ttn/scram/7thconf/aermod/aermet_userguide.zip.

456 EPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19. http://www.epa.gov/air/sulfurdioxide/pdfs/20110411so2designationsguidance.pdf.

introduce conservatism" into the model, but rather to "Reclaim data that was "lost" due to coding, making station more representative."[457] Furthermore, EPA "recommends that AERMINUTE should routinely be used to supplement the standard NWS data with hourly-averaged winds based on the 1-minute ASOS wind data (when available)."[458]

These recommendations have also been presented in a March 2013 Clarification Memo from EPA:[459]

> Given the limitations and significant concerns regarding the adequacy of standard ASOS data, and considering the relevant recommendations in the *Guideline* related to these concerns, we recommend that AERMINUTE be routinely used to supplement the standard ASOS data with hourly-averaged wind speed and direction to support AERMOD dispersion modeling. Since the 1-minute ASOS wind data used as input to AERMINUTE are freely available to the public, this recommendation should not impose any significant burden on permit applicants applying the AERMOD model.[460]

EPA summarizes the recommended use of ASOS meteorological data as follows:

- EPA has developed the AERMINUTE processor to calculate hourly average winds from 1-minute ASOS winds, whose purpose is to replace the single 2-minute winds that represent an hour with an hourly-averaged wind that is reflective of actual conditions and more appropriate for input for dispersion modeling.
- EPA recommends that AERMINUTE be routinely used in general practice in AERMOD modeling as the hourly average winds better reflect actual conditions over the hour as opposed to a single 2-minute observation.
- EPA has also implemented a threshold option in AERMET to treat winds below the threshold as calms, with a recommended minimum wind speed of 0.5 m/s, consistent with the threshold required for site-specific data.[461]

The SJVAPCD also has procedures that apply AERMINUTE and one-minute

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457 James Thurman, EPA/OAQPS, AERMINUTE, 10th Conference on Air Quality Modeling. http://www.epa.gov/ttn/scram/10thmodconf/presentations/1-7-aerminute_update.pdf.

458 Roger Brode, EPA/OAQPS, Appendix W: Clarification Memoranda, 10th Conference on Air Quality Modeling. http://www.epa.gov/ttn/scram/10thmodconf/presentations/1-4-Brode_10thMC_AppW_ClarificationMemos_03-13-2012.pdf.

459 EPA, Use of ASOS Meteorological Data in AERMOD Dispersion Modeling, March 8, 2013. http://www.epa.gov/ttn/scram/guidance/clarification/20130308_Met_Data_Clarification.pdf.

460 *Id.*, p. 12.

461 *Id.*, p. 13.

ASOS winds.[462] From the SJVAPCD Procedure for Downloading and Processing NCDC Meteorological Data:

> To reduce the number of calms and missing winds in the surface data, archived 1-minute winds for the ASOS stations can be used to calculate hourly average wind speed and directions, which are used to supplement the standard archive of hourly observed winds processed in AERMET (EPA, 2010b).

At a minimum, the PDOC modeling should be based on 2008 through 2012 Meadows Field Airport meteorological data, which incorporate one-minute wind data processed with EPA's AERMINUTE program. A threshold wind speed of 0.5 meter per second should also be applied to the AERMET processing of these data.

We prepared 2008 through 2012 Meadows Field Airport meteorological data incorporating EPA's recommended use of AERMINUTE and one-minute wind data. This improved meteorological data set has about 4.4% calm winds, compared to the 27% calm winds found in the 2006 through 2010 PDOC modeling data set. Our modeling analysis using the more representative meteorological data found significantly higher 24-hour PM10 impacts than were predicted using the less representative 2006 through 2010 data.

Methods Used to Prepare 2008 – 2012 Meteorological Data

The meteorological data required by AERMOD is prepared by AERMET. Required data inputs to AERMET are: surface meteorological data, twice-daily soundings of upper air data, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. [463] AERMET creates the model-ready surface and profile data files required by AERMOD. Using AERMET v. 12345, we created an AERMOD-ready meteorological data set to model the proposed HECA facility. This data set covered five years, 2008 through 2012, and is summarized as follows:

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[462] SJVAPCD, Procedure for Downloading and Processing NCDC Meteorological Data, Final, Version 3.1, April 2013, p. 8. http://www.valleyair.org/busind/pto/Tox_Resources/MeteorologicalDataProcessing4-11-13.pdf.

[463] Albedo is the fraction of total incident solar radiation reflected by the surface back to space (whiter surfaces have higher albedo). The Bowen ratio is an indicator of surface moisture. It is the ratio of sensible heat flux to latent heat flux and drier areas have a higher Bowen ratio. Surface roughness, shown in shorthand as ("z_0"), is an essential parameter in estimating turbulence and diffusion. Technically, it's the height above the ground that the log wind law extrapolates to zero. For our purposes, z_0 can be thought of as a measure of how much the surface characteristics interfere with the wind flow. Very smooth surfaces, like short grass or calm ponds, have very low values of z_0 -- on the order of 0.01 meter or less. Tall and irregular surfaces, which are a greater obstacle to wind flow, have higher values of z_0 – up to 1.0 meter or more for forests.

Meteorological data used for modeling the HECA facility:

– Surface data: Meadows Field Airport (KBFL);
– Upper air data: Oakland International Airport (KOAK).

Surface Meteorological Data

We used 2008 through 2012 Integrated Surface Hourly ("ISH") data obtained from the National Climatic Data Center ("NCDC"). From the ISH dataset, we extracted ASOS data from the Meadows Field Airport.

We also obtained 2008 through 2012 one-minute ASOS wind data from the Meadows Field Airport, which we processed with AERMINUTE v. 11325. We downloaded these one-minute data from the NCDC.[464] We input the ice-free wind instrument start date (March 14, 2007) and used default settings with AERMINUTE. As a quality assurance measure, we compared values developed from the one-minute data with the corresponding ISH data file.

We processed the ISH data through AERMET Stage 1, which performs data extraction and quality control checks. We merged the AERMINUTE output files with the processed AERMET Stage 1 ISH and upper air data in AERMET stage 2.

Upper Air Meteorological Data

We used 2008 through 2012 upper air data from twice-daily radiosonde measurements obtained from Oakland International Airport. These data are in Forecast Systems Laboratory ("FSL") format which we downloaded in ASCII text format from the FSL website maintained by the National Oceanic and Atmospheric Administration ("NOAA").[465] We downloaded and processed all reporting levels with AERMET.

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. We processed the FSL upper air data through AERMET Stage 1, which performs data extraction and quality control checks.

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[464] *See*: ftp://ftp.ncdc.noaa.gov/pub/data/asos-onemin/.

[465] Available at: http://esrl.noaa.gov/raobs/.

AERSURFACE and Final Processing

We used AERSURFACE v. 13016 to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site (Meadows Field Airport). Using AERSURFACE, we extracted surface roughness in a one kilometer radius surrounding the data collection site. We also extracted Bowen ratio and albedo for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. We processed these micrometeorological data for seasonal periods using 30-degree sectors.

We applied the AERSURFACE outputs in Stage 3 AERMET processing. At this point, we also incorporated a 0.5 meter/second threshold velocity for one-minute ASOS winds that had been processed with AERMINUTE. We did not fill missing hours in the meteorological data sets as the data files exceed USEPA's 90% data completeness requirement.[466]

Modeling Results

The corrected HECA PM10 impacts include revisions to paved road fugitive emissions, modeling with receptor flagpole heights, and using 2008 through 2012 Bakersfield meteorological data processed with current USEPA recommendations. Using AERMOD v. 12345, our modeling results for 24-hour average PM10 impacts are presented below.

The 24-hour PM10 Significant Monitoring Concentration (10 $\mu g/m^3$) and the 24-hour PM10 CAAQS (50 $\mu g/m^3$) are based on highest modeled 24-hour impacts. Our modeling analysis incorporating fugitive dust emission rate and modeling corrections shows that HECA's 24-hour PM10 impacts will exceed both of these regulatory design concentrations. The highest 24-hour average PM10 impacts from the HECA project are shown in the following table:

[466] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 – 5-5. http://www.epa.gov/ttn/scram/guidance/met/mmgrma.pdf.

Table 6b: 24-hour PM10 Significant Monitoring Concentration

Year of Meteorological Data	Highest 1st High 24-hr PM10 Concentration (μg/m^3)	Easting Coordinate (meters)	Northing Coordinate (meters)
2008	55.59	283970.70	3912099.90
2009	42.42	283982.40	3912599.80
2010	34.23	283966.70	3911925.00
2011	47.16	283973.10	3912199.90
2012	39.33	283971.90	3912149.90

The 24-hour PM10 PSD increment (30 μg/m^3) is based on the second-highest modeled 24-hour impact for each year modeled. Our modeling analysis incorporating fugitive dust emission rate and modeling corrections shows that HECA's 24-hour PM10 impacts will exceed this regulatory design concentration. The second-highest 24-hour average PM10 impacts from the HECA project are shown in the following table:

Table 6c: Second-Highest 24-hour PM10 Significant Monitoring Concentration

Year of Meteorological Data	Highest 2nd High 24-hr PM_{10} Concentration (μg/m^3)	Easting Coordinate (meters)	Northing Coordinate (meters)
2008	46.25	283970.70	3912099.90
2009	34.79	283965.50	3911875.00
2010	32.96	283972.50	3912174.90
2011	34.02	283970.70	3912099.90
2012	35.15	283971.90	3912149.90

VIII.D.3 Revised Modeling Results Indicate that HECA's 24-hour PM10 Impact Exceeds Regulatory Design Concentrations

The PDOC finds that the HECA's 24-hour PM10 impact is 98% of the 24-hour PM10 SIL. This finding, however, is based on underestimates in the emission rate calculations and improper model inputs. Correcting the inappropriate paved road PM10 emissions, and correcting the model inputs identified above, will result in 24-hour PM10 impacts much greater than the SIL. In fact, these corrections will lead to violations of the following regulatory design concentrations:

– The 24-hour PM10 Significant Monitoring Concentration (10 μg/m^3),

– The 24-hour PM10 PSD increment (30 μg/m^3), and
– The 24-hour PM10 CAAQS (50 μg/m^3).

In addition, the corrected PM10 impacts from the HECA project may cause or contribute to PM10 NAAQS violations in an area that is very close to becoming nonattainment for this pollutant.

None of these significant impacts were identified in the PDOC due to the incorrect finding that the 24-hour PM10 impacts are below the SIL. The PDOC must be revised to incorporate the corrected 24-hour PM10 emission rates and subsequent modeling analyses.

IX. THE PDOC FAILS TO ADDRESS NUISANCE AND POTENTIAL INJURY OR DAMAGE TO BUSINESS OR PROPERTY

The PDOC does not address the potential impacts of HECA on nearby businesses and properties. District Rule 4102, Section 4.1, requires:

> A person shall not discharge from any source whatsoever such quantities of air contaminants or other materials which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such person or the public or which cause or have a natural tendency to cause injury or damage to business or property.

The PDOC must evaluate the Project's potential direct and indirect impacts on local farms and other businesses, including emissions and materials from the facility as well from all of the associated trains and trucks.

Fugitive coal dust along rail lines is a major concern. Although HECA first indicated that coal will be shipped using covered rail cars, it subsequently disclosed that the coal will be shipped in open-top rail cars.[467] Publicly available testimony from coal companies before the Surface Transportation Board (STB) states that each rail car loses between 250 and 700 pounds of coal and coal dust on each trip for an average loss of 500 pounds of coal lost from each car per trip.[468] The local citizen group Association of Irritated Residents ("AIR") recently posted a report including video footage to the

[467] HECA Responses to CEC Workshop Requests: Nos. A33 through A37, December 2012, p. 5; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-12-19_Applicants_Responses_to_Requests_A33-A37_TN-68931.pdf.

[468] Hearing Transcript and Recording, July 29, 2010, Arkansas Electric Cooperative Association – Petition for Declaratory Order, Surface Transportation Board, Docket No. FD 35305, tape 1 at Transcript (Tr.) at 102:9-103:7, 37:07, 1h:42; Tr. at 42:5-13, 102:9-103:7 (BNSF Testimony).

CEC demonstrating that there are already large amounts of coal spillage along the BNSF railroad in Kern County between Bakersfield and Wasco.[469]

Air pollution and coal dust from the trains may have adverse impacts on crops – a major component of the region's economy – that far outweigh any alleged economic benefits.[470] The proposed project site is surrounded by highly productive agricultural land where pistachios, almonds, alfalfa, grapes, onions, tomatoes, wheat, cotton, and other crops are grown. Agricultural crops can be injured when exposed to high concentrations of various air pollutants. Injury ranges from visible markings on the foliage, to reduced growth and yield, to premature death of the plant. For example, alfalfa crops are susceptible to sulfur dioxide pollution that HECA would emit.[471] The local farming community has expressed numerous concerns about how the HECA project may impact or contaminate soils, crop yields and crop value.[472]

> All we need, all we need here in this area is for one scare, one scare to come from this plant to say that there's something in the air, there's something in the soil, there's something coming from this plant that is polluting our crops. Whether it be pistachios or almonds or cherries or grapes or any other product that's grown in this area. And then we get a call from our processors that say, I don't think we want your product anymore because of your proximity to that plant and what can happen to this -- to your products and could devastate the entire product.[473]

The District must evaluate how increased air pollution from the HECA project and transportation corridors would impact the crops in the area surrounding the plant. The analysis should include direct impacts to the crops as well as indirect impacts to the soil and irrigation water and economic impacts.

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[469] Status Report Six from the Association of Irritated Residents (AIR), April 11, 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/others/2013-04-11_AIR_status_report_06_TN-70272.pdf.

[470] These impacts should also be evaluated in the District's alternatives analysis under section 173(a)(5).

[471] Ontario, Ministry of Agriculture, Food and Rural Affairs, Revision of Factsheet, Air Pollution on Agricultural Crops, Order No. 85-002, printed June 2003; http://www.omafra.gov.on.ca/english/crops/facts/01-015.htm.

[472] For example, email exchange between Robert Worl, CEC, and Chris Romanini, February 2013; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2013-02-28_CEC_Email_Exchange_with_Intervenor_HECA_Neighbors_C_Romanini_Regarding_Air_Quality_and_Water_TN-69828.pdf; and HECA Reponses to AIR Data Requests Nos. 12 through 42, November 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/2012-11-30_Applicants_Responses_to_AIR_Data_Requests_Nos_12_through_42_TN-68731.pdf.

[473] Informational Hearing and U.S. Department of Energy Scoping Meeting before the Energy Resources Conservation and Development Commission of the State of California, In the Matter of the: Amended Application for Certification for the Hydrogen Energy Project, Docket No. 08-AFC-08A, July 12, 2012; http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/2012-07-12_Transcript_of_Informational_Meeting_TN-2933.pdf

X. OTHER COMMENTS AND RECOMMENDATIONS

The PDOC's formulaic structure, which clings to a generic outline provided by the District, results in an impenetrable document that is not adequate to inform the public of the consequences of this complex project. The document could be much improved by revising its organization. Further, the document includes a number of erroneous statements, imprecise descriptions, and typographical errors:

Organization

- Sierra Club recommends that the District include a more detailed table of contents including subheadings for both the main document and the appendices to improve navigability of the document.

- Sierra Club recommends that all assumptions and calculations are contained within in one section for each emissions unit rather than first laying out all assumptions for all emissions units, then calculating PTE for all emissions units, then determining BACT for all emissions units, etc. which makes the PDOC difficult to follow especially given the lack of a detailed table of contents.

- Sierra Club recommends that the facility-wide general conditions repeated for each permit unit at the beginning of their respective compliance conditions in Appendix A be separated from the unit-specific conditions and presented in a separate facility-wide section. This facility-wide section should also include the compliance conditions addressing fugitive dust, which are repeated at end of each permit unit.

- Sierra Club recommends that the respective permit unit ID be repeated in the header of the section containing the compliance condition for each emission unit.

- Sierra Club recommends that the title of Appendix F "Emission Information" be revised to specifically refer to HRSG and coal drying stack operating scenarios.

Erroneous Statements and Content

- The PDOC, Appendix K, p. 48, provides that the refined ambient air quality standard analysis demonstrates "that emissions from HECA will not cause or contribute to exceedance of a NAAQS and/or CAAQS for any affected pollutant." Yet the results of the analysis presented in Table 8-5, provided on the next page, contradict this statement showing that HECA emissions will contribute significantly to existing exceedances of the 24-hour and annual PM10 and PM2.5 NAAQS, 24-hour PM10 CAAQS, annual PM2.5 CAAQS.

- The PDOC, Appendix K, Table 8-5, p. 49, incorrectly references the annual CAAQS for PM2.5 at 15 $\mu g/m^3$ instead of 12 $\mu g/m^3$.

- The PDOC, Table 6-2, p. 12; Appendix K, Table 8-1, p. 37; Appendix K, Table 8-5, p. 49, and Appendix K-A, p. 64; incorrectly reference the superseded annual NAAQS for PM2.5 of 15 $\mu g/m^3$ instead of the new annual NAAQS of 12 $\mu g/m^3$ adopted by EPA on January 15, 2013 and effective March 18, 2013.[474]

Imprecise Description

- The PDOC, p. 59, provides that CO emission factor of 2.0 lb/MMBtu on unshifted syngas from the gasification flare is based on supplier data from "first project". It is unclear which "first project" the PDOC refers to as there have been several revisions to the Project including a change of gasifier technology, change of feedstock blend from 100% petcoke to 75% coal/25% petcoke, and addition of a fertilizer manufacturing facility which resulted in multiple revisions to the AFC process before the CEC. Sierra Club recommends that the PDOC provide a definition of "first project" and discuss why the CO emission factor from that project remains applicable to the HECA Project.

- The PDOC, p. 54, provides that that the breakdown of operation for the maximum duration of venting episodes from the CO_2 recovery and vent system, *i.e.*, a cumulative 504 hours/year, is "explained in the table below" but fails to provide such a table. Presumably, the PDOC refers to the table "Carbon Dioxide Venting Scenarios" on page 31 of the PDOC.

- The PDOC variously refers to the "coal dryer" and "feedstock dryer."

Typographical Errors

- The PDOC, Appendix C, p. C-5: "therefore BACT for SOx emissions is satisfied" should read "therefore BACT for PM10 emissions is satisfied."

- The PDOC, p. 121, incorrectly refers to "Rule 2201 section 4.13.2.2" instead of "Rule 2201 section 4.13.3.2."

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[474] 78 Fed. Reg. 3086 (Jan. 15, 2013).

- In Appendix C, p. C-31, the PDOC erroneously refers to a maximum heat input limit for the heater of 7.7 billion Btu per year instead of 7.84 billion Btu.[475]

- The PDOC, Appendix K, p. 121, incorrectly refers to SJVAPCD Rule 2201, Section 4.13.2.2 instead of Section 4.13.3.2.

- The PDOC, p. 81, incorrectly converts emissions from the CO_2 vent of 5,672 lb/year VOC (as methane) to 2.34 tons/year, instead of 2.84 tons/year. The PDOC, Appendix A, p. A-43, implements this incorrect annual emission estimate into condition of compliance No. 9 for the CO_2 recovery and vent system (S-7616-24-0).

- The PDOC, p. 51, refers to the compound "C3H3" as accounted for in the estimate of VOC emissions from fugitive equipment leaks. Presumably, the PDOC instead refers to propylene, or "C_3H_6," which is found in several process streams.

- The PDOC, p. 82, incorrectly refers to equipment unit S-7616-27-0 as "Cooling Tower Serving Power Block and Process Units" instead of "Cooling Tower Serving Gasification Block and Process Units."

475 PDOC, Appx. C, p. C-31.

Exhibit A

Public Record Request C-2013-2-44: ERC for HECA

Inbox x

Turn on highlighting Print all

Jim Swaney <Jim.Swaney@valleyair.org> Feb 15

to me

David,

Attached is a document that contains the ERC histories for the ERC's that HECA has proposed to use. Once you review this, please let me know what information you would like to receive concerning these ERC's.

One other thing I wanted to let you know about, as you indicated you will be providing comments on the project, is that we have received a request to hold a public hearing about the project, and will therefore extend the public commenting period. Once the hearing is scheduled, we will let you know what the extension on comments will be.

Thanks,
Jim

Jim Swaney, P.E.
Permit Services Manager
Valley Air District
(559) 230-6000
(559) 230-6061 fax
www.valleyair.org
www.healthyairliving.com

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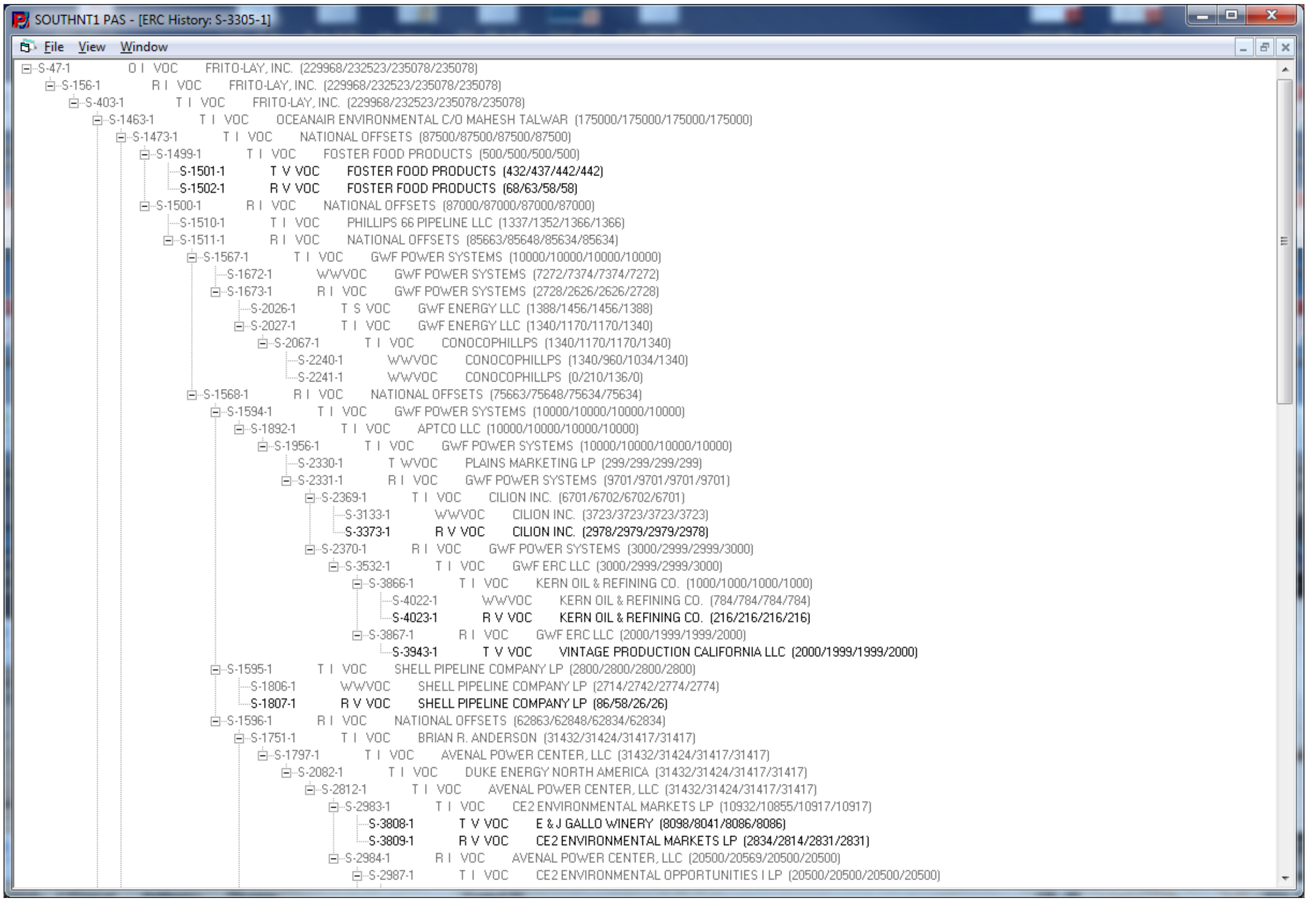
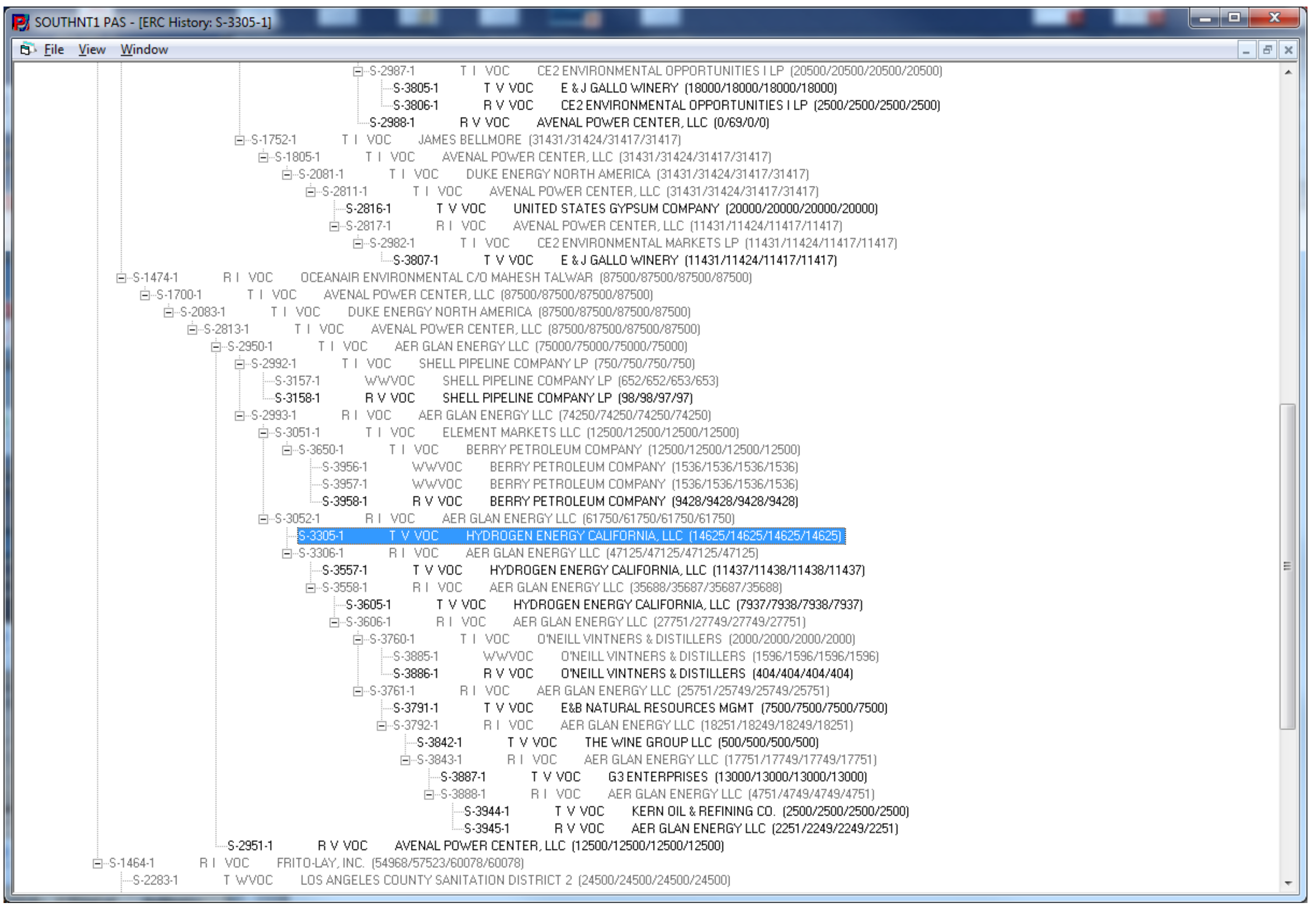
ERC history for HECA ERC.docx
608K View Download

Click here to Reply or Forward

ERC History for S-3305-1, S-3557-1 and S-3605-1


SOUTHNT1 PAS - [ERC History: S-3305-1]
File View Window
S-47-1 O I VOC FRITO-LAY, INC. (229968/232523/235078/235078)
S-156-1 R I VOC FRITO-LAY, INC. (229968/232523/235078/235078)
S-403-1 T I VOC FRITO-LAY, INC. (229968/232523/235078/235078)
S-1463-1 T I VOC OCEANAIR ENVIRONMENTAL C/O MAHESH TALWAR (175000/175000/175000/175000)
S-1473-1 T I VOC NATIONAL OFFSETS (87500/87500/87500/87500)
S-1499-1 T I VOC FOSTER FOOD PRODUCTS (500/500/500/500)
S-1501-1 T V VOC FOSTER FOOD PRODUCTS (432/437/442/442)
S-1502-1 R V VOC FOSTER FOOD PRODUCTS (68/63/58/58)
S-1500-1 R I VOC NATIONAL OFFSETS (87000/87000/87000/87000)
S-1510-1 T I VOC PHILLIPS 66 PIPELINE LLC (1337/1352/1366/1366)
S-1511-1 R I VOC NATIONAL OFFSETS (85663/85648/85634/85634)
S-1567-1 T I VOC GWF POWER SYSTEMS (10000/10000/10000/10000)
S-1672-1 W W VOC GWF POWER SYSTEMS (7272/7374/7374/7272)
S-1673-1 R I VOC GWF POWER SYSTEMS (2728/2626/2626/2728)
S-2026-1 T S VOC GWF ENERGY LLC (1388/1456/1456/1388)
S-2027-1 T I VOC GWF ENERGY LLC (1340/1170/1170/1340)
S-2067-1 T I VOC CONOCOPHILLPS (1340/1170/1170/1340)
S-2240-1 W W VOC CONOCOPHILLPS (1340/960/1034/1340)
S-2241-1 W W VOC CONOCOPHILLPS (0/210/136/0)
S-1568-1 R I VOC NATIONAL OFFSETS (75663/75648/75634/75634)
S-1594-1 T I VOC GWF POWER SYSTEMS (10000/10000/10000/10000)
S-1892-1 T I VOC APTCO LLC (10000/10000/10000/10000)
S-1956-1 T I VOC GWF POWER SYSTEMS (10000/10000/10000/10000)
S-2330-1 T W VOC PLAINS MARKETING LP (299/299/299/299)
S-2331-1 R I VOC GWF POWER SYSTEMS (9701/9701/9701/9701)
S-2369-1 T I VOC CILION INC. (6701/6702/6702/6701)
S-3133-1 W W VOC CILION INC. (3723/3723/3723/3723)
S-3373-1 R V VOC CILION INC. (2978/2979/2979/2978)
S-2370-1 R I VOC GWF POWER SYSTEMS (3000/2999/2999/3000)
S-3532-1 T I VOC GWF ERC LLC (3000/2999/2999/3000)
S-3866-1 T I VOC KERN OIL & REFINING CO. (1000/1000/1000/1000)
S-4022-1 W W VOC KERN OIL & REFINING CO. (784/784/784/784)
S-4023-1 R V VOC KERN OIL & REFINING CO. (216/216/216/216)
S-3867-1 R I VOC GWF ERC LLC (2000/1999/1999/2000)
S-3943-1 T V VOC VINTAGE PRODUCTION CALIFORNIA LLC (2000/1999/1999/2000)
S-1595-1 T I VOC SHELL PIPELINE COMPANY LP (2800/2800/2800/2800)
S-1806-1 W W VOC SHELL PIPELINE COMPANY LP (2714/2742/2774/2774)
S-1807-1 R V VOC SHELL PIPELINE COMPANY LP (86/58/26/26)
S-1596-1 R I VOC NATIONAL OFFSETS (62863/62848/62834/62834)
S-1751-1 T I VOC BRIAN R. ANDERSON (31432/31424/31417/31417)
S-1797-1 T I VOC AVENAL POWER CENTER, LLC (31432/31424/31417/31417)
S-2082-1 T I VOC DUKE ENERGY NORTH AMERICA (31432/31424/31417/31417)
S-2812-1 T I VOC AVENAL POWER CENTER, LLC (31432/31424/31417/31417)
S-2983-1 T I VOC CE2 ENVIRONMENTAL MARKETS LP (10932/10855/10917/10917)
S-3808-1 T V VOC E & J GALLO WINERY (8098/8041/8086/8086)
S-3809-1 R V VOC CE2 ENVIRONMENTAL MARKETS LP (2834/2814/2831/2831)
S-2984-1 R I VOC AVENAL POWER CENTER, LLC (20500/20569/20500/20500)
S-2987-1 T I VOC CE2 ENVIRONMENTAL OPPORTUNITIES I LP (20500/20500/20500/20500)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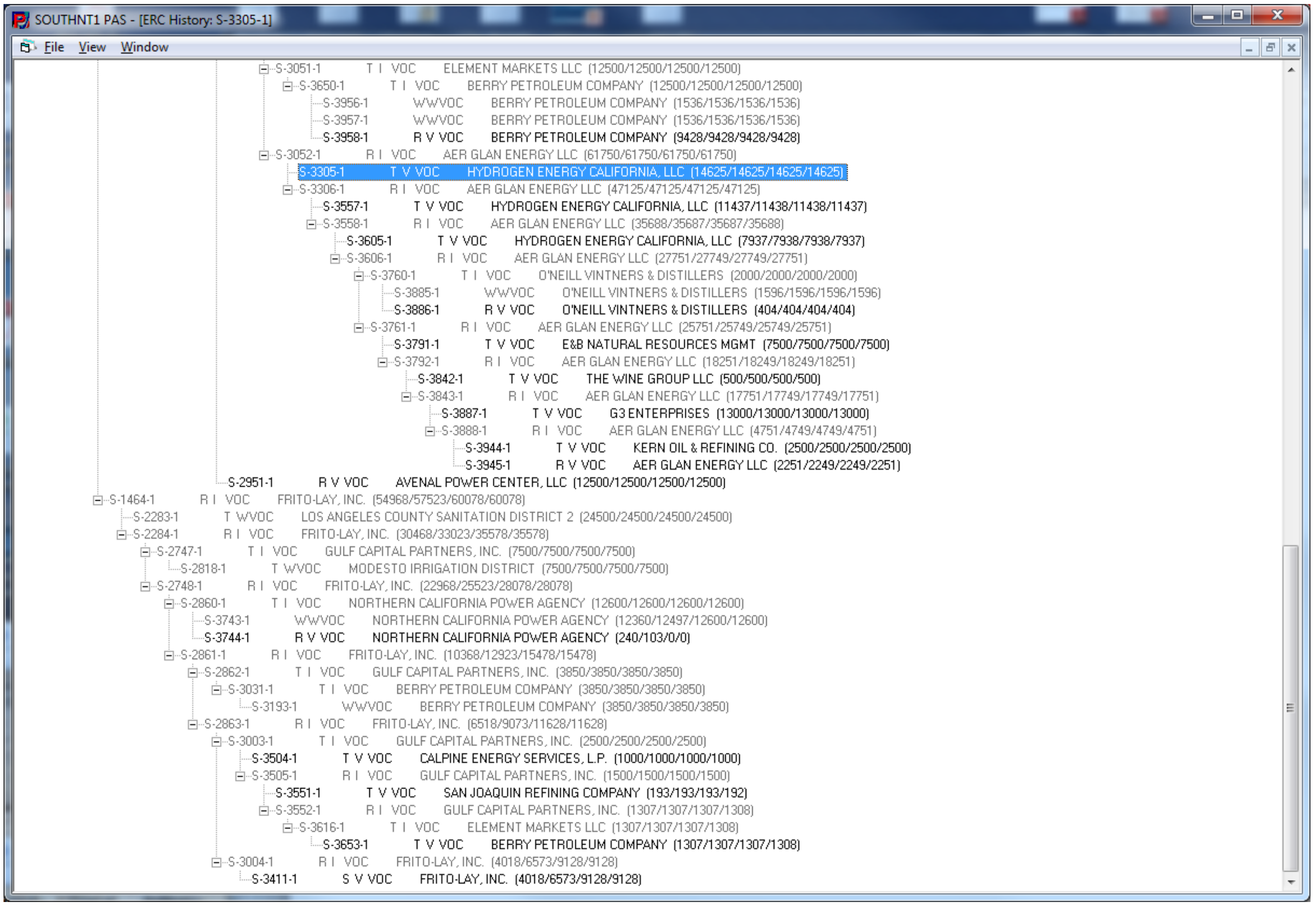
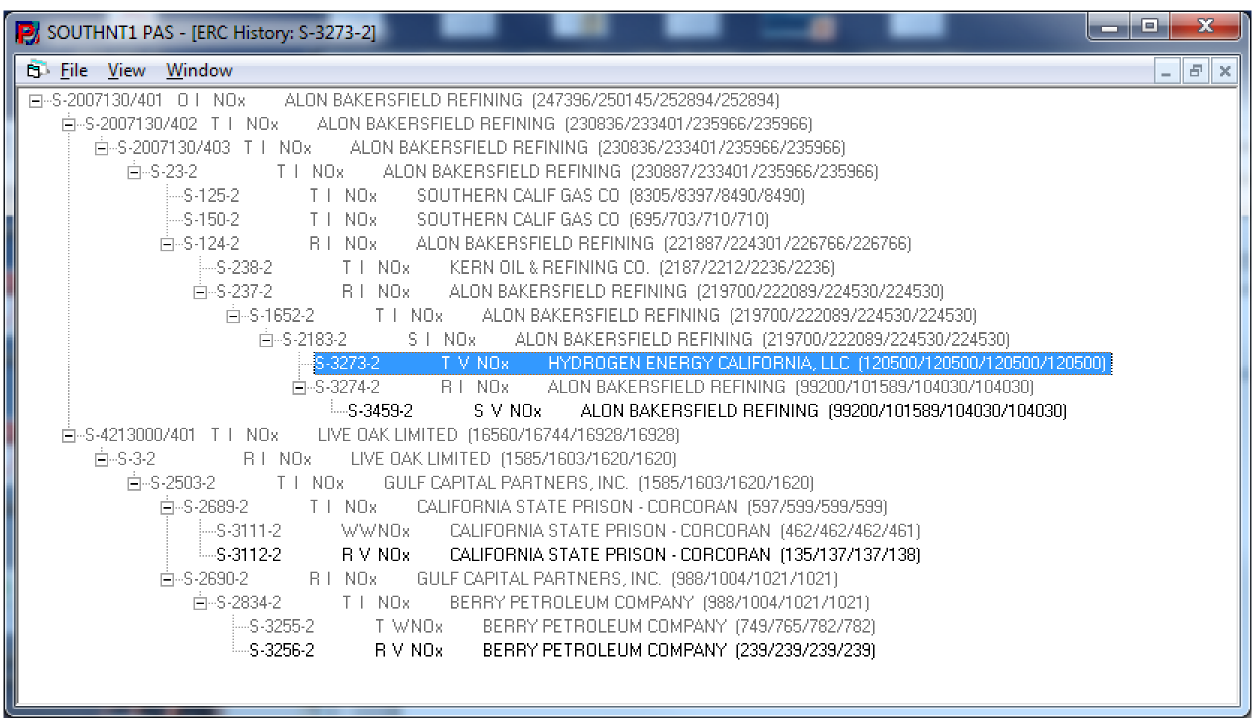
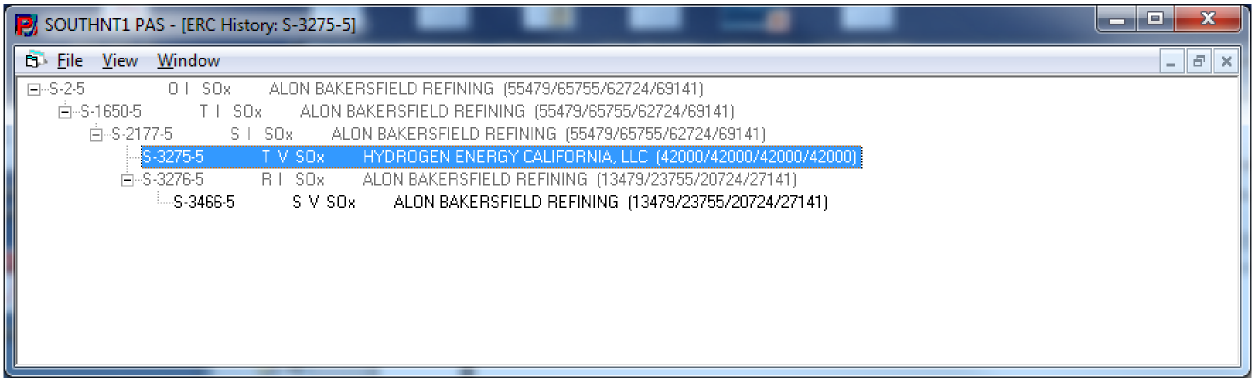
S-2987-1 T I VOC CE2 ENVIRONMENTAL OPPORTUNITIES I LP (20500/20500/20500/20500)
S-3805-1 T V VOC E & J GALLO WINERY (18000/18000/18000/18000)
S-3806-1 R V VOC CE2 ENVIRONMENTAL OPPORTUNITIES I LP (2500/2500/2500/2500)
S-2988-1 R V VOC AVENAL POWER CENTER, LLC (0/69/0/0)
S-1752-1 T I VOC JAMES BELLMORE (31431/31424/31417/31417)
S-1805-1 T I VOC AVENAL POWER CENTER, LLC (31431/31424/31417/31417)
S-2081-1 T I VOC DUKE ENERGY NORTH AMERICA (31431/31424/31417/31417)
S-2811-1 T I VOC AVENAL POWER CENTER, LLC (31431/31424/31417/31417)
S-2816-1 T V VOC UNITED STATES GYPSUM COMPANY (20000/20000/20000/20000)
S-2817-1 R I VOC AVENAL POWER CENTER, LLC (11431/11424/11417/11417)
S-2982-1 T I VOC CE2 ENVIRONMENTAL MARKETS LP (11431/11424/11417/11417)
S-3807-1 T V VOC E & J GALLO WINERY (11431/11424/11417/11417)
S-1474-1 R I VOC OCEANAIR ENVIRONMENTAL C/O MAHESH TALWAR (87500/87500/87500/87500)
S-1700-1 T I VOC AVENAL POWER CENTER, LLC (87500/87500/87500/87500)
S-2083-1 T I VOC DUKE ENERGY NORTH AMERICA (87500/87500/87500/87500)
S-2813-1 T I VOC AVENAL POWER CENTER, LLC (87500/87500/87500/87500)
S-2950-1 T I VOC AER GLAN ENERGY LLC (75000/75000/75000/75000)
S-2992-1 T I VOC SHELL PIPELINE COMPANY LP (750/750/750/750)
S-3157-1 W W VOC SHELL PIPELINE COMPANY LP (652/652/653/653)
S-3158-1 R V VOC SHELL PIPELINE COMPANY LP (98/98/97/97)
S-2993-1 R I VOC AER GLAN ENERGY LLC (74250/74250/74250/74250)
S-3051-1 T I VOC ELEMENT MARKETS LLC (12500/12500/12500/12500)
S-3650-1 T I VOC BERRY PETROLEUM COMPANY (12500/12500/12500/12500)
S-3956-1 W W VOC BERRY PETROLEUM COMPANY (1536/1536/1536/1536)
S-3957-1 W W VOC BERRY PETROLEUM COMPANY (1536/1536/1536/1536)
S-3958-1 R V VOC BERRY PETROLEUM COMPANY (9428/9428/9428/9428)
S-3052-1 R I VOC AER GLAN ENERGY LLC (61750/61750/61750/61750)
S-3305-1 T V VOC HYDROGEN ENERGY CALIFORNIA, LLC (14625/14625/14625/14625)
S-3306-1 R I VOC AER GLAN ENERGY LLC (47125/47125/47125/47125)
S-3557-1 T V VOC HYDROGEN ENERGY CALIFORNIA, LLC (11437/11438/11438/11437)
S-3558-1 R I VOC AER GLAN ENERGY LLC (35688/35687/35687/35688)
S-3605-1 T V VOC HYDROGEN ENERGY CALIFORNIA, LLC (7937/7938/7938/7937)
S-3606-1 R I VOC AER GLAN ENERGY LLC (27751/27749/27749/27751)
S-3760-1 T I VOC O'NEILL VINTNERS & DISTILLERS (2000/2000/2000/2000)
S-3885-1 W W VOC O'NEILL VINTNERS & DISTILLERS (1596/1596/1596/1596)
S-3886-1 R V VOC O'NEILL VINTNERS & DISTILLERS (404/404/404/404)
S-3761-1 R I VOC AER GLAN ENERGY LLC (25751/25749/25749/25751)
S-3791-1 T V VOC E&B NATURAL RESOURCES MGMT (7500/7500/7500/7500)
S-3792-1 R I VOC AER GLAN ENERGY LLC (18251/18249/18249/18251)
S-3842-1 T V VOC THE WINE GROUP LLC (500/500/500/500)
S-3843-1 R I VOC AER GLAN ENERGY LLC (17751/17749/17749/17751)
S-3887-1 T V VOC G3 ENTERPRISES (13000/13000/13000/13000)
S-3888-1 R I VOC AER GLAN ENERGY LLC (4751/4749/4749/4751)
S-3944-1 T V VOC KERN OIL & REFINING CO. (2500/2500/2500/2500)
S-3945-1 R V VOC AER GLAN ENERGY LLC (2251/2249/2249/2251)
S-2951-1 R V VOC AVENAL POWER CENTER, LLC (12500/12500/12500/12500)
S-1464-1 R I VOC FRITO-LAY, INC. (54968/57523/60078/60078)
S-2283-1 T W VOC LOS ANGELES COUNTY SANITATION DISTRICT 2 (24500/24500/24500/24500)



ERC History of S-3273-2



ERC History for S-3275-5



ERC History for C-1058-2

ERC History for C-1058-5

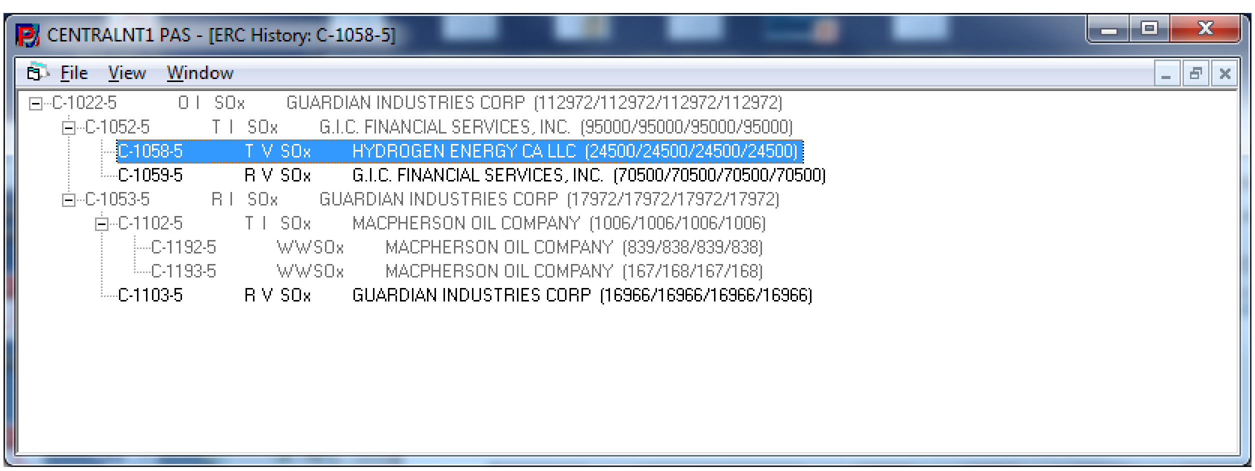


Exhibit B

KERN UNTY AIR POLLUTION CONTROI ISTRICT

1701 "H" Street, Suite 250
Bakersfield, California 93301
Telephone (805) 861-3682

LEON M HEBERTSON, M.D.
Director of Public Health
Air Pollution Control Officer

February 25, 1983

Mr. H. C. Bradbury
Group Manager-Environmental Compliance
Frito-Lay, Inc.
P. O. Box 47250
Dallas, Texas 75247

Dear Mr. Bradbury:

Thank you for your recent letter in which you discuss the Continental Carbon Bakersfield facility's air contaminant emissions. The District has reviewed this facility's specific limiting conditions (contained in Permits to Operate), fuel oil and feedstock average sulfur content (0.8%), and applicable E.P.A. AP-42 emission factors. The following allowable emissions credits were determined from these data. Please note that the hydrocarbon emissions reflect a 50% reduction due to the exclusion of methane. (KCAPCD Rule 210.1 does not allow the use of methane as an emissions tradeoff because it is considered non-photochemically reactive.) The numbers below represent total facility emissions and are in units of lbm/day. Line #1 production rate was considered to be 35.73 tons/day and that of line #2 to be 35.90 tons/day.

Particulates	Carbon Monoxide	Hydrocarbons
560.1	131,848.2	2,388.3
Hydrogen Sulfide	Oxides of Nitrogen	Sulfur Dioxide
753.4	1,059.[illegible]	5,512.[illegible]

Even though some of these values are somewhat lower than summarized in your letter, it appears (on the basis of expected emissions summarized in your rough draft A to C application package) that these emissions credits would provide adequate offsets (at a ratio of 1.2:1) for the Frito-Lay plant proposed for Kern County.

Thank you for your cooperation. Should you have any questions, please telephone the Air Quality Control Division at (805) 861-3682.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Thomas Paxson, P.E., Manager
Engineering Evaluation Section

TP/dl

Exhibit C

ERC APPLICATION REVIEW

6026001/101/201/401/501/601

Facility Name: FRITO-LAY, INC.
Mailing Address: 222801 Highway 58
Bakersfield, CA 93312

Project #: 6026 920416
WP File #: 92LE026

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

ERC APPLICATION REVIEW

DEEMED COMPLETE:	6/22/92	ENGINEER:	Lance Ericksen
DATE START:	4/16/92	TITLE::	Senior AQE
DATE FINISH:	12/16/92		

6026001/101/201/401/501/601

Facility Name: FRITO-LAY, INC.
Mailing Address: 222801 Highway 58
Bakersfield, CA 93312

Project #: 6026 920416
WP File #: 92LE038

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

I. PROPOSAL:

This review is required to in order revise the amount of NO2 credit and conditions *noticed in the preliminary decision to grant* ERC *Banking Certificates* to Frito-Lay. The previous notice was published September 19, 1992. The revisions are necessary to respond to two of the comments received from the applicant during the public comment period:

Comment 1

In the preliminary decision analysis (page 10) the permitted production rate and actual emissions were used to determine the NO2 emission factor. Firto-lay commented the actual production rate during the source test should be used to establish the emission factor. In response to this comment the NO2 emission factor calculation was revised. This results in an increase in the amount of NO2 emission reduction credits previously noticed.

Comment 2

The Banking and New Source Review Rules now in effect contain provisions for the use of shutdown credits and any reductions banked under these rules should be subject to these provisions. The applicant commented that the reductions were limited to use at their snack food facility because the rules that were in effect at the time the reductions were originally recognized did not provide for use of shutdown emissions however, the previous agreements allow the use at their facility. In response to this comment the use of these reductions will not be restricted to the Frito-lay snack food facility.

The remainder of this analysis includes all original pages from the preliminary decision ERC Application Review noticed on September 19, 1992. If a page has not been revised it is noted at the top of the page. If a page is replaced it is shown in strike out after the revised page.

I. **PROPOSAL CONT.:**

In response to comments from Frito-Lay the following emission reductions have been found to qualify for banking:

	Pounds per Quarter				
	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	18,702	229,968	90,000
2nd Qt	25,252	163,500	18,910	232,523	91,000
3rd Qt	25,530	165,296	19,118	235,078	92,000
4th Qt	25,530	165,296	19,118	235,078	92,000

Note: only the amount of NO2 is revised.

~~ERC APPLICATION REVIEW~~

~~DEEMED COMPLETE: 6/22/92~~
~~DATE START: 4/16/92~~
~~DATE FINISH:~~

~~ENGINEER: Lance Ericksen~~
~~TITLE: Senior AQE~~
~~6026001/101/201/401/501/601~~

~~Facility Name: FRITO-LAY, INC.~~
~~Mailing Address: 222801 Highway 58~~
~~Bakersfield, CA 93312~~

~~Project #: 6026-920416~~
~~WP File #: 92LE026~~

~~Contact Name: H.C. Bradbury~~
~~Title: Group Manager, Environmental Policy & Affairs~~
~~Phone: (214) 334-4742~~

~~I. SUMMARY:~~

~~The applicant is requesting ERC Banking Certificates for reductions occurring prior to January 1, 1988. The reductions were obtained from the shutdown of Continental Carbon a carbon black production facility for use as offsets at the Frito-Lay snack food facility. These reductions were recognized in writing by the District as available for offsets prior to adoption of the Kern County banking rule. This allows the applicant to apply for ERC Banking Certificates pursuant to pursuant to Rule 230.1 IV.A.1. As the offsets were previously recognized for use only at the Frito-Lay facility any credits available for banking will also be limited for use at the Frito-Lay Snack Food Facility.~~

~~A portion of the original reductions was used for approval of the current Frito-Lay Snack Food Facility in addition a portion of the reductions were donated to the KCAPCD in 1989. The reductions dedicated to previous projects and the portion donated to the District is not surplus and the applicant has not requested to bank these amounts. Of the remaining previously recognized credits the PM10, SO2, VOC and CO qualify for banking as actual emission reductions. The amount of NO2 previously recognized as available for offsets was based on the permit limitation not actual emissions. The amount of NO2 credit requested has therefore been reduced to the remaining actual emissions.~~

~~The following emission reductions have been found to qualify for banking:~~

	Pounds per Quarter				
	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	3,960	229,968	90,000
2nd Qt	25,252	163,500	4,004	232,523	91,000
3rd Qt	25,530	165,296	4,048	235,078	92,000
4th Qt	25,530	165,296	4,048	235,078	92,000

II. APPLICABLE RULES:

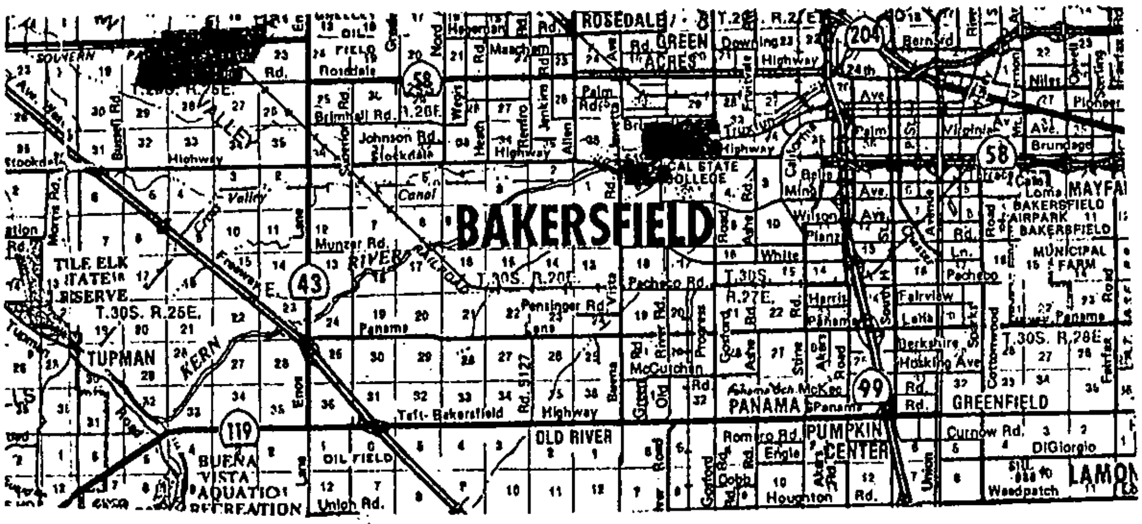
Rule 230.1 - Emission Reduction Credit Banking (March 11, 1992)

To qualify for banking the emissions reductions must comply with the requirements of subsection IV.A.2. The requirements of this subsection are summarized below:

1. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.
2. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable.
3. The reductions have not been used for the approval of an Authority to Construct or used as offsets.
4. The reductions are included in or have been added to the 1987 emissions inventory.
5. The banking application must be filed within 180 days of the date of rule adoption.

III. LOCATION:

The carbon black facility was located 8 miles west of Bakersfield on Stockdale Highway Section 14, Township 32S, Range 23E. The Frito-Lay facility is located west of Bakersfield on highway 58 at Section 20, Township 29S, Range 25E. A map showing the relative locations of the facilities are shown on page 3. The use of these reductions as offsets at the Frito-Lay Snack Food Facility will be subject to the distance offset ratios required by the New Source Review Rule.



Location of reductions 20801 Stockdale Hwy

PAGE NOT REVISED

IV. METHOD OF GENERATING REDUCTIONS:

The applicant has applied to bank reductions which were obtained from Continental Carbon generated by the shutdown of their carbon black manufacturing operation. Frito-Lay acquired the operating permits for the facility in order to provide offsets for their snack food manufacturing facility. These reductions occurred prior to adoption of a banking rule in Kern County. In order to maintain the emissions reductions for future use as offsets Frito-Lay has maintained permits on some of the carbon black manufacturing operation. Under the provisions of Rule 230.1 adopted September 19, 1991 in order to continue to maintain these reductions for use as offsets Frito-Lay must obtain ERC Banking Certificates. These reductions have previously been recognized and quantified by the following events:

Date	Summary
9/10/79	Continental Carbon (CC) Shutdown
7/1/82	Frito-Lay (dba The Food Company) Purchases CC PTOs
9/13/~~92~~82	Letter from TFC to KCAPCD Requesting Emissions Reductions be Established for Offsets
12/22/82	Letter from TFC to KCAPCD Requesting Emissions Revising 9/13/82 Request.
2/25/82	Letter from KCAPCD Recognizing Credits
4/25/83	KCAPCD Adopts Banking Rule
11/11/83	Frito-Lay Issued ATCs Using a Portion of Credits for Offsets
12/21/87	Letter from KCAPCD to Frito-Lay Describing Methods to Maintain Remaining Credits for Future Use
6/21/88	Letter from KCAPCD to Frito-Lay Recognizing Remaining Credits

The use of these credits by Frito-Lay has previously been reviewed by CARB and EPA.

V. CALCULATIONS:

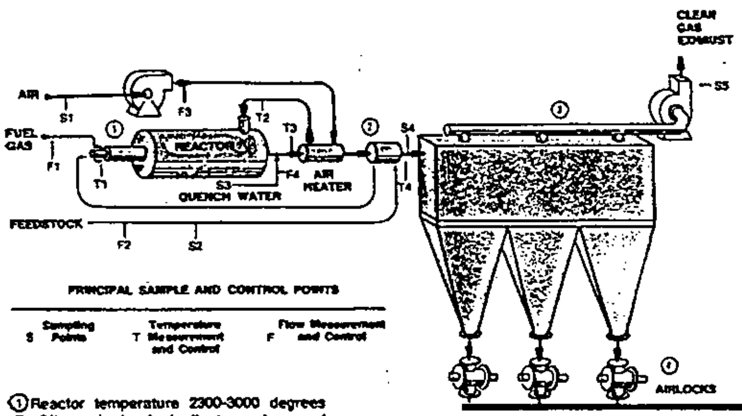
A. General

The carbon black facility was comprised of two independent carbon black production trains. Unit 1 produced a hard type or tread grade carbon black. Unit 2 produced a soft type or carcass grade carbon black. Both units used the oil furnace process for production of carbon black. Flow diagrams and a description of the process used is shown on page 5A .

Credits generated are associated with eight permits to operate for the carbon black facility the equipment associated with each permit is:

6026001	Unit 1 Reactors
6026002	Unit 1 Pulverizer/pelletizers
6026003	Unit 1 Dryer
6026004	Unit 1 Screens/separators/storage/bagging/loadout
6026005	Unit 2 Reactors
6026006	Unit 2 Pulverizer/pelletizers
6026007	Unit 2 Dryer
6026008	Unit 2 Screens/separators/storage/bagging/loadout

Page 5A



①Reactor temperature 2300-3000 degrees F. Oil cracked principally to carbon and hydrogen.

②Carbon-laden gasses cooled by direct water sprays (to about 1000 degrees F.), further cooled by heat exchange with process air and feedstock.

③Cooled reaction mixture (400-500 degrees F.) passes into silicone-coated glass fabric bags; closed end at top, open end inserted into cell plates at the floor.

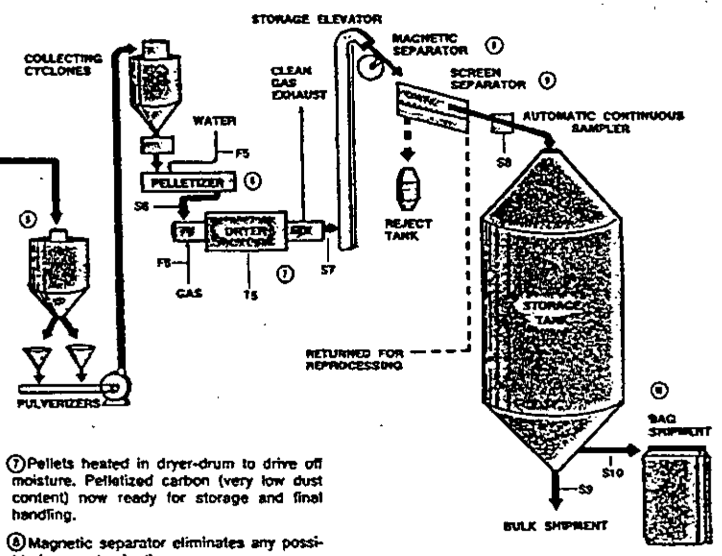
④Outlet-header damper valves close at preset intervals (one filter at a time). Reverse flow of clean effluent gas forces collected carbon black to fall into hopper.

⑤Pulverizers break up and disperse very small quantities of agglomerates if present.

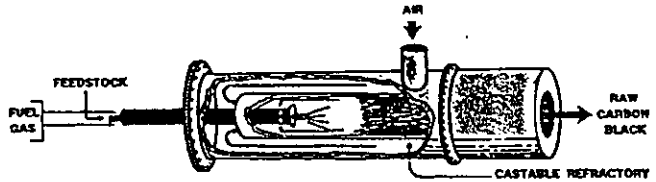
⑥Pulverized black (light, fluffy product with density about 3-4 lbs/ft³) conveyed to tubular mixing box for pelletizing. Water sprayed in, black and water whipped into small pellets by revolving pins.

⑩Black packaging done by specially-designed air-flow valve packer developed by Continex engineers. Filling and weighing automatic, check weighed on second scale. Operator hand closes bag when weight exact.
From check weighing, bags automatically transferred to bag shaper, unitizing-glue applicator, and stacked on pallets.
Material being pulled into bags identified by production date marked on each pallet. Grade printed on bags.

Bulk storage uses different identification method since blending occurs during loading and unloading. Preshipment tests define and assure exact quality.



QUALITY "BUILT IN" AT HEART OF PROCESS — THE AUTOMATIC CONTINEX BLACK REACTOR



Simplified representation of "typical" Continex Reactor

Specific designs vary for carcass-grade and tread-grade blacks. Include internal baffling and other design features. Basic construction, however, extremely straightforward and amenable to precise automatic control.

Consistent production of quality carbon black requires consistent reactor conditions — temperature, flow rates, and dimensions. Continex reactors are easily maintained to exact inside dimensions. Reaction tubes are easily changed when wear first occurs. The internal design may be altered quickly for rapid response to specific quality and product demands.

Continex-reactor design came from years of experimentation and pilot-plant testing. The critical reaction tubes are fabricated by lining pipe with high-grade castable alumina refractory. These tubes are the key to stable operations and are carefully made by the people responsible for their use.

⑦Pellets heated in dryer-drum to drive off moisture. Pelletized carbon (very low dust content) now ready for storage and final handling.

⑧Magnetic separator eliminates any possible iron contamination.

⑨In the screen separator large pellets are trapped by the top, coarse screen. Desired material is trapped by the middle, fine screen. Very fine material falls through both screens and is combined with the large material for reprocessing.

continex®

Continental Carbon Company
Witco Chemical Corporation

Continex, the long mileage carbon blacks.

V. CALCULATIONS:

B. PM-10, CO and VOC Emissions Reductions

Emission reductions previously recognized by the District of PM-10, CO and VOC are based on AP-42 Table 5.3-3 emission factors and actual carbon black production for the facility. These factors were adjusted to reflect recycle of main process vent gases installed at the facility in 1978. Source testing showed recirculation reduced emissions of CO and VOC by 29.5%. Carbon black production data for the baseline period is shown on page 7.

Emission factors used for PM10, CO and VOC are:

	Pounds/Ton Product		
	PM10	CO	VOC (non-methane)
Main process vent	6.53	2,800	100
Combined dryer vent	0.45	-	-
Pneumatic system vent	0.58	-	-
Oil storage tank vent	-	-	1.44
Vacuum clean-up system	0.06	-	-
Fugitive emissions	0.20	-	-
Total	7.82	2,800	101.44
Less 29.5% (no impact TSP)	-	826	29.92
Emission Factor	7.82	1,974	71.52

(Note: as the dryer vent at this facility was uncontrolled a factor of .45 was used)

Conversion of TSP to PM-10

As noted in AP-42 page 5.3-1 Carbon Black is "... extremely fine black fluffy particulate, 10 to 500 nm diameter. Therefore although the AP-42 factor is listed as TSP it can be concluded that all emissions of particulate matter from the carbon black production facility are also 10 microns or less. Thus the TSP emissions are 100% PM-10.

Average daily emissions over the baseline period are therefore:

	PM10	VOC	CO
Unit 1	279.4	2555.2	70,531.0
Unit 2	280.7	2221.4	61,317.2
Total	560.1	4776.6	131,848.2

PAGE NOT REVISED

V. CALCULATIONS CONT.:

Production Data:

YEAR	Pounds/Year Carbon Black Unit #1	Pounds/Year Carbon Black Unit #2
1979	21,116,800	27,492,600
1978	20,848,100	24,922,400
1977	30,000,300	25,828,200
1976	18,703,000	21,786,500
1975	24,327,900	25,190,700
1974	32,349,100	26,538,000
1973	32,037,800	30,009,200
1972	29,294,000	27,865,100
Average (8 years)	26,084,625	26,204,087
Tons/Day (lbs/year/ 365x2000)	35.73	35.90

PAGE NOT REVISED

V. CALCULATIONS CONT.:

C. SO2 Emissions Reductions

The quantity of SO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility.

SOx specific limiting condition 198.9 lbs/hr x 24 hr/day

= 4,773.6 pounds/day

This previously recognized amount was compared to actual emissions over the baseline method using AP-42 emission factors and by a method (mass balance for sulfur in fuel, feedstock and carbon black) reported by I. Drogin in the Journal of the Air Pollution Control Association. These calculations of actual emissions (see pages ______) indicate actual emissions are equivalent to the specific limiting condition. Therefore the previously recognized SO2 emissions may be considered actual emissions reductions.

PAGE NOT REVISED

V. CALCULATIONS CONT.:

D. NO2 Emissions Reductions

The quantity of NO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. The specific limiting conditions for the permit are the maximum legal emission from an operation and therefore do not quantify real and actual emissions over the baseline period. To quantify actual emissions of NO2 source test data for the stationary source from November 1978 was used with the actual carbon black production over the baseline period. The source test data is summarized as follows:

Unit #	Stack #	Description	NO2 lb/hr	
1	1	Main Bagfilter	5.97	
1	2	Main Bagfilter	6.10	
1	3	Oil Preheater	1.30	
1	4	Firebox Stack	13.80	
1	5	Exhaust Bagfilter	1.79	Total Unit 1 28.96
2	6	Main Bagfilter	0.32	
2	7	Main Bagfilter	0.28	
2	8	Oil Preheater	0.72	
2	9	Firebox Stack	9.69	
2	10	Exhaust Bagfilter	2.53	Total Unit 2 13.53
		Boiler #1	not tested	
		Boiler #2	not tested	

V. CALCULATIONS CONT.:

Actual emissions over the baseline period are:

Basis:

Source test unit 1 NO_2 emissions 28.96 lbs/hr
Source test unit 1 production rate 52.80* tons/day
Average unit 1 production rate 35.73 tons/day (see page 7)

Source test unit 2 NO_2 emissions 13.53 lbs/hr
Source test unit 2 production rate 53.76* tons/day
Average unit 2 production rate 35.90 tons/day (see page 7)

Unit 1 Actual NO_2 Emissions:

$$\frac{28.96\text{ lb}}{\text{hr}} \Big| \frac{24\text{hr}}{\text{day}} \Big| \frac{35.73\text{ tons/day average}}{52.80\text{ tons/day test}} = \underline{\underline{470.34\text{ lbs/day}}}$$

Unit 2 Actual NO_2 Emissions:

$$\frac{13.53\text{ lb}}{\text{hr}} \Big| \frac{24\text{hr}}{\text{day}} \Big| \frac{35.90\text{ tons/day average}}{53.76\text{ tons/day test}} = \underline{\underline{216.84\text{ lbs/day}}}$$

Total NO_2 Actual Emissions 470.34 + 216.84 = 687.2 lbs/day

* Revised per information submitted by applicant showing actual production rate see Appendix A

~~V. CALCULATIONS CONT.:~~

~~Actual emissions over the baseline period are:~~

~~Basis:~~

~~Source test unit 1 NO2 emissions 28.96 lbs/hr~~
~~Source test unit 1 production rate 6381.7 lbs/hr or 76.56 tons/day~~
~~Average unit 1 production rate 35.73 tons/day (see page _____)~~

~~Source test unit 2 NO2 emissions 13.53 lbs/hr~~
~~Source test unit 2 production rate 4887.6 lbs/hr or 58.56 tons/day~~
~~Average unit 2 production rate 35.90 tons/day (see page _____)~~

~~Unit 1 Actual NO2 Emissions:~~

~~28.96 lb~~	~~24hr~~	~~35.73 tons/day average~~	~~=~~	~~324.37 lbs/day~~
~~hr~~	~~day~~	~~76.56 tons/day test~~		

~~Unit 2 Actual NO2 Emissions:~~

~~13.53 lb~~	~~24hr~~	~~35.90 tons/day average~~	~~=~~	~~199.07 lbs/day~~
~~hr~~	~~day~~	~~58.56 tons/day test~~		

~~Total NO2 Actual Emissions 324.37 + 199.07 = 523.44 lbs/day~~

TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S}) (64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /50	0 /4293
Dryer Vent	0.52/0	37.2/0
Boilers	142S (lbs/10[6] gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S) (0.50) (64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

Continental Carbon Company

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

VI. COMPLIANCE:

A. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

The emission reductions were recognized in writing by the District in February 25, 1983. A copy of this correspondence is shown Appendix B. Kern County Air Pollution Control District Rule 210.3 - Emission Reductions Banking was adopted April 25, 1983 therefore, at the time the reductions were recognized the District did not have a banking rule. The reductions therefore satisfy the requirement that they were recognized in writing in a county that did not have a banking rule.

B. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable;

Actual Emissions Reductions

The Rule 230.1 definition of Actual Emissions Reductions states they are as defined in the District's New Source Review Rule. If the reductions are authorized by an Authority to Construct the adjustments made to the actual emissions reductions be as defined in the New and Modified Source Rule, shall be based on the rules, plans, workshop notices at the time the application for such Authority to Construct was deemed complete.

The Rule 220.1 definition of Actual Emissions Reductions states in part they are reductions of actual emissions from an emissions unit selected for emission offsets or banking, from the baseline period. Actual emission reductions shall be calculated pursuant to section V of this rule

The Rule 220.1 definition of Actual Emissions states they are measured or estimated emissions which most accurately represent the emissions from an emissions unit.

Rule 220.1 section V. - Calculations - states the following procedures shall be performed separately for each pollutant, and for each emissions unit or for a concurrent stationary source modification. All calculations shall be performed on a quarterly basis, unless specified otherwise.

For the shutdown of an emissions unit section V.E.2. of Rule 220.1 requires the actual emission reduction to be the Historic Actual Emissions prior to shutdown. Section V. also defines historic actual emissions as emissions having actually occurred based on source tests or calculated using actual fuel consumption or process weight, recognized emissions factors or other data approved by the Control Officer which most accurately represent the emissions during the baseline period.

VI. COMPLIANCE:

The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.

The baseline period used in the original quantification of the emissions reductions was the eight year period 1972-1979. The use of this baseline period is not prohibited by Rules 220.1 and 230.1. These reductions were calculated on an annual daily basis. Because this type of source is not subject to seasonal variations emissions can be expected to be evenly distributed over the year. Thus the reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1:

	Daily Emissions	Reference Page	
PM10	560.1	8	6
SO2	2,768.3	22	8
NO2	687.2	26	10
VOC	4,776.6	8	6
CO	131,848.2	8	6

— 4773-6/1/94

Quarterly Emissions

	First	Second	Third	Fourth
Days/Qtr	90	91	92	92
PM10	50,409	50,969	51,529	51,529
SO2	249,147	251,915	254,684	254,684
NO2	61,848	62,535	63,222	63,222
VOC	429,894	434,671	439,447	439,447
CO	11,866,338	11,998,186	12,130,034	12,130,034

As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.

~~VI. COMPLIANCE:~~

~~The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.~~

~~The baseline period used in the original quantification of the emissions reductions was the eight year period 1972-1979. The use of this baseline period is not prohibited by Rules 220.1 and 230.1. These reductions were calculated on an annual daily basis. Because this type of source is not subject to seasonal variations emissions can be expected to be evenly distributed over the year. Thus the reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1.~~

	~~Daily Emissions~~	~~Reference Page~~
~~PM10~~	~~560.1~~	~~8~~
~~SO2~~	~~2,768.3~~	~~22~~
~~NO2~~	~~523.4~~	~~26~~
~~VOC~~	~~4,776.6~~	~~8~~
~~CO~~	~~131,848.2~~	~~8~~

~~Quarterly Emissions~~

	~~First~~	~~Second~~	~~Third~~	~~Fourth~~
~~Days/Qtr~~	~~90~~	~~91~~	~~92~~	~~92~~
~~PM10~~	~~50,409~~	~~50,969~~	~~51,529~~	~~51,529~~
~~SO2~~	~~249,147~~	~~251,915~~	~~254,684~~	~~254,684~~
~~NO2~~	~~47,106~~	~~47,629~~	~~48,153~~	~~48,153~~
~~VOC~~	~~429,894~~	~~434,671~~	~~439,447~~	~~439,447~~
~~CO~~	~~11,866,338~~	~~11,998,186~~	~~12,130,034~~	~~12,130,034~~

~~As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.~~

VI. COMPLIANCE:

Real

The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. The reductions therefore represent real emissions.

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:

	Pounds/Day				
	PM10	SO2	NO2	VOC	CO
Actual Reductions	560.1	4773.6	687.2	4776.6	131,848.2
Used for Snack Food Facility Offsets	282.5	303.0	479.4	-	-
Donated to District	-	2673.9	-	2221.4	130,848.2
Balance Surplus Reductions	277.5	1796.7	207.8	2555.2	1,000.0

Permanent

All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.

Quantifiable

Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The reductions therefore are quantifiable.

~~VI. COMPLIANCE:~~

~~Real~~

~~The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. The reductions therefore represent real emissions.~~

~~Surplus~~

~~The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions are as follows:~~

	~~Pounds/Day~~				
	~~PM10~~	~~SO2~~	~~NO2~~	~~VOC~~	~~CO~~
~~Actual Reductions~~	~~560.1~~	~~4773.6~~	~~523.4~~	~~4776.6~~	~~131,848.2~~
~~Used for Snack Food Facility Offsets~~	~~282.5~~	~~303.0~~	~~479.4~~	~~-~~	~~-~~
~~Donated to District~~	~~-~~	~~2673.9~~	~~-~~	~~2221.4~~	~~130,848.2~~
~~Balance Surplus Reductions~~	~~277.5~~	~~1796.7~~	~~44.0~~	~~2555.2~~	~~1,000.0~~

~~Permanent~~

~~All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.~~

~~Quantifiable~~

~~Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The reductions therefore are quantifiable.~~

VI. **COMPLIANCE:**

Enforceable

The permits to operate for the carbon black facility will be surrendered any new construction or operation of existing equipment at the site will require Authority to Construct pursuant to Rule 2010 and will be subject to new source review prior to construction or operation. The reductions are therefore enforceable.

C. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting remaining (surplus) emissions reductions are shown on page 13 .

D. The reductions are included in or have been added to the 1987 emissions inventory.

Upon original approval of these emissions reductions the District required that these emissions be included in the current NAP inventory. To insure the proper amount of emissions is included District planning staff will be informed whenever all or a portion of these emissions are used as offsets for the Frito-Lay facility.

E. The banking application must be filed within 180 days of the date of rule adoption.

The application for emission reduction banking credits was submitted to the District March 17, 1992. This is within 180 days September 19, 1991 the date of rule adoption.

F. Because these emission reductions can be validated as Actual Emission Reductions they qualify for ERC banking certificates that may be used in accordance with the requirements of Rule 220.1.

VII. **RECOMMENDATION:**

Issue ERC banking certificated to Frito-Lay, ~~subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito Lay snack foods processing plant at their present site and may not be sold or traded~~.

After public notice and review issue ERC Banking Certificates in the following amounts:

Pounds/Day From Page 13

PM10	SO2	NO2	VOC	CO
277.5	1796.7	207.8	2555.2	1000

Pounds/Quarter

	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	18,702	229,968	90,000
2nd Qt	25,252	163,500	18,910	232,523	91,000
3rd Qt	25,530	165,296	19,118	235,078	92,000
4th Qt	25,530	165,296	19,118	235,078	92,000

~~VII. RECOMMENDATION:~~

~~Issue ERC banking certificated to Frito-Lay subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito-Lay snack foods processing plant at their present site and may not be sold or traded.~~

~~After public notice and review issue ERC Banking Certificates in the following amounts:~~

~~Pounds/Day From Page ____~~

~~PM10~~	~~SO2~~	~~NO2~~	~~VOC~~	~~CO~~
~~277.5~~	~~1796.7~~	~~44.0~~	~~2555.2~~	~~1000~~

~~Pounds/Quarter~~

	~~PM10~~	~~SO2~~	~~NO2~~	~~VOC~~	~~CO~~
~~1st Qt~~	~~24,975~~	~~161,703~~	~~3,960~~	~~229,968~~	~~90,000~~
~~2nd Qt~~	~~25,252~~	~~163,500~~	~~4,004~~	~~232,523~~	~~91,000~~
~~3rd Qt~~	~~25,530~~	~~165,296~~	~~4,048~~	~~235,078~~	~~92,000~~
~~4th Qt~~	~~25,530~~	~~165,296~~	~~4,048~~	~~235,078~~	~~92,000~~

APPENDIX A

PRODUCTION DATA DURING SOURCE TEST

OBJECTIVE: **DETERMINE CARBON BLACK PRODUCTION RATE FOR UNIT #1 DURING 11/78 STACK TEST**

INPUTS:

- Tests were conducted on 11/2, 11/5 and 11/6/78.
- Unit #1 was producing N339 grade carbon black during test period. For N339, 4.365 lbs carbon black are produced for every gallon of feedstock charged to the reactors.
- The following feedstock charge oil rates were recorded by Agency representatives. These rates represent the total charged to Reactors #1, 3, 4 & 5.

DATE	TIME	FEEDSTOCK CHARGE RATE (gph)
11/2/78	0925	1030
11/2/78	1037	1031
11/2/78	1325	1030
11/6/78	1020	1012
11/6/78	1056	1006
11/6/78	1107	1008
11/6/78	1200	1004
11/6/78	1230	1007
11/6/78	1300	1000
11/6/78	1525	984
11/6/78	1542	984
	AVG.	1008

See sample of orignal records

RECEIVED
OCT 29 1992
SAN JOAQUIN VALLEY UNIFIED APCD—SOUTHERN REGION

ANALYSIS

(4.365 lbs carbon black/gal feedstock)(1008 gph feedstock) = 4399.9 lbs/hr or 2.2 TPH

(2.2 TPH) (24 hrs/day) = 52.80 TPD carbon black production (Unit #1)

CONCLUSION

Unit #1 Reactors were producing an average of 52.80 TPD of N339 grade carbon black during the November, 1978 test period. This is approximately 70% of the maximum production capacity for Unit #1 (6381.7 lbs/hr or 76.56 TPD).

OBJECTIVE: **DETERMINE CARBON BLACK PRODUCTION RATE FOR UNIT #2 DURING 11/78 STACK TEST**

INPUTS:

- Tests were conducted on November 14--17, 1978.
- N660 was the carbon black grade being produced. N660 is produced at a rate of 5.622 lbs/gal feedstock charged to the reactor(Unit #2 had only one operating reactor, designated as reactor #2).
- The following feedstock charge oil rates were recorded by Agency representatives.

DATE	TIME	FEEDSTOCK CHARGE RATE (gph)
11/14/78	Avg.	777
11/15/78	Avg.	783
11/16/78	Avg.	810
11/17/78	Avg.	819
	AVG.	797

ANALYSIS

(5.622 lbs carbon black/gal feedstock) (797 gph feedstock) = 4480.7 lbs/hr or 2.24 TPH

(2.24 TPH) (24 hrs/day) = 53.76 TPD carbon black production (Unit #2)

CONCLUSION

Unit #2 reactor was producing an average of 53.76 TPD of N660 grade carbon black during the November, 1978 test period. This is approximately 90% of the maximum production capacity for Unit #2 (4887.6 lbs/hr or 58.56 TPD).

CONTINENTAL CARBON CO.

PRODUCT N339

11-2-78

9:25

By T. GOFF
w/ McDONALD, [illegible]

ACTOR	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR ×1200 = scfh
1	220 gal/hr	6 ≈ 10,000 sft³/hr	6.95 ≈ 147,000 sft³/hr	14 = 1680 s[illegible]
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH
1		990°F		660°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
3	273 gal/hr		6.95 ≈ 147,000 sft³/hr	6. 7320 sft³/hr
	FUEL OIL	REACTOR QUENCH T.	AIR PREHEAT T	DUCT QUENCH
3	69.5 gal/hr	900°F		680°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
4	285 gal/hr		7.0 ≈ 148,000 sft³/hr	5.65 = 6780 s
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH T
4	69.5 gal/hr	885°F		675°F
	CHARGE OIL	FUEL GAS	COMB. AIR	AXIAL AIR
5	252 gal/hr		7.0 ≈ 150,000 sft³/hr	7.15 = [illegible]
	FUEL OIL	REACTOR QUENCH T	AIR PREHEAT T	DUCT QUENCH
5	[illegible] gal/hr	885°F		645°F

	RATIO (black)	COMBUSTION AIR (RED)	WASTE GAS (GREEN)	TEM
HEATER	0.38	4.1 = 1640 sft³/hr	4.4 = ~~39,650 sft³/hr~~ 44,000 sft³/hr	

Dev'n #1

Total Charge Oil
1030 gph

Dev'n #2

Page 19

Total Chg Rate 1030
" Fuel Oil Rate 206

Exhibit D

RESOURCE MANAGEMENT AGENCY

RANDALL L. ABBOTT
DIRECTOR

DAVID PRICE III
ASSISTANT DIRECTOR

Air Pollution Control District
WILLIAM J. RODDY, APCO

Environmental Health Services Department
STEVE McCALLEY, REHS, DIRECTOR

Planning & Development Services Department
TED JAMES, AICP, DIRECTOR

July 24, 1991

MR. DAVID C. HOWEKAMP, Director
Air and Toxics Division
Environmental Protection Agency, Region IX
75 Hawthorne Street
San Francisco, California 94105

Re: Use of Continental Carbon Company Emission Reductions as Offsets by Frito-Lay

Dear Mr. Howekamp:

On November 11, 1983, the Kern County Air Pollution Control District issued Authorities to Construct (ATC's) to Frito-Lay, Inc., for the first phase of a salty snack food production facility (EPA approval NSS 4-3). Offsets used to mitigate the air quality impact of the new equipment were provided by the December 1981 shutdown of the Continental Carbon Black production stationary source located approximately six miles from the Frito-Lay facility. As you will recall, EPA agreed to use of these reductions as offsets for Frito-Lay's planned snack foods production facilities. In accordance with a letter dated April 10, 1984, from EPA to Dr. Leon Hebertson, Air Pollution Control Officer, Kern County Air Pollution Control District, EPA permitted use of the Continental Carbon Company offsets for the Frito-Lay project, including expansion of the project consistent with the original project environmental impact report. Frito-Lay has maintained Permits to Operate carbon black manufacturing equipment (with emissions limitations reduced by the amounts of consumed offsets) since acquiring ownership of the Permits in September 1983.

Frito-Lay recently indicated they now wish to seek approval for additional snack food lines consistent with the original project description. Frito-Lay intends to utilize the remaining emissions represented by the Continental Carbon Permits to Operate inorder to offset expected emissions increases.

2700 "M" STREET, SUITE 350 BAKERSFIELD, CALIFORNIA 93301 (805) 861-350 FAX: (805) 861-342

Page Two
Mr. David C. Howekamp
July 24, 1991

The San Joaquin Valley Unified Air Pollution Control District intends to comply with previous EPA and Kern Air Pollution Control District commitments by permitting the use of Continental Carbon Company offsets for the new snack food lines. If you disagree with this determination, please advise me prior to Monday, August 5, 1991.

If you desire additional information, please telephone me at (805) 861-3502.

Very truly yours,

RANDALL L. ABBOTT, Director
Resource Management Agency

RLA:rrk

Enclosure

Exhibit E

THE FOOD COMPANY

9226 South Vermont Avenue
Los Angeles, California 90044

September 13, 1982

Mr. Tom Paxson
Air Sanitation Engineer IV
Kern County Air Pollution Control District
1601 H Street, Suite 250
Bakersfield, California 93301

Dear Mr. Paxson:

Per our discussion of September 2, 1982, please find the enclosed attachment regarding Continental Carbon's Bakersfield facility emissions and establishment of corresponding emission reduction credits for use by the Food Company (TCFC, Inc.). In summary these are:

	lbs/day
Particulate	559.49
Carbon Monoxide	141,239.70
Hydrocarbons	5,117.26
Hydrogen Sulfide	3,026.60
Sulfur Dioxide	4,773.60
Nitrogen Oxides	1,059.36

As previously indicated, we are eager to submit a preliminary "Application to Construct" for our proposed Kern County Facility. Submittal of this preliminary document will occur following endorsement by our management of Kern County as a plant setting and the optioning of specific sites.

We are appropriately interested in reviewing the proposed Kern County Banking Rule and would welcome the opportunity to participate as a non-oil producer in its development.

I will be contacting you in the near future to schedule a time to review our draft permit application. If you should have any questions regarding the enclosure or otherwise, please advise.

Sincerely,

THE FOOD COMPANY (TCFC, INC.)

HC Bradbury

H.C. Bradbury
Group Manager, Environmental Compliance

BCC:

PF# A-1	Sam Frenk
Trudy Wright	Liza Urso

cc: Howard Franck, General Counsel
Continental Carbon, Inc.

0904S/HCB/sb

CONTINENTAL CARBON EMISSION CREDITS

I. Carbon Black Production (avg. of yrs. '72 through '79): 52,288,712 lbs/yr (See Attachment 1)

$$\frac{52{,}228{,}712 \text{ lbs/yr}}{2000 \text{ lbs/ton } (365 \text{ days/yr})} = 71.55 \text{ ton/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP42 emission factors for Carbon Black Manufacture (B Oil furnace process), 7/79.

PROCESS	EMISSION FACTORS (lbs/ton of Product)			
	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Main Process Vent	6.53	2,800	100	60
Dryer Vent Uncontrolled (Firebox)	.45	---	---	---
Pneumatic System Vent Bag Filter	.58	---	---	---
Oil Storage Tank Vent	---	---	1.44	---
Vacuum Cleanup System Vent	.06	---	---	---
Fugitive Emissions	.20	---	---	---
SOURCE TOTAL	7.82	2,800	101.44	60
Less 29.5% for Modification in 1978 does not impact TSP.	---	826	29.92	17.70
Emission Factor Total	7.82	1,974	71.52	42.30
III. Total Emissions Credit in lbs/day of Pollutant (Factor x ton. Finished Product/Day)	559.49	141,239.70	5,117.26	3,026.60

Emission credits for SO_2 and NO_x are based on the "Specific Limiting Conditions" identified in Continental Carbons Permit to Operate, as outlined by Kern County APCP Rule 210.1.

SO_2 Specific Limiting Condition is 198.9 lbm/hr
198.9 lb/hr (24 hrs/day) = 4,773.60 lbs/day

NO_x Specific Limiting Condition is 44.14 lbm/hr
44.14 lb/hr (24 hrs/day) = 1,059.36 lbs/day

0904S/HCB/sb

Exhibit F

State of California
AIR RESOURCES BOARD
Attachment A to Resolution 79-68
Adopted: September 12, 1979

Kern County
NEW SOURCE REVIEW RULES

RULE 210.1 Standard for Authority to Construct:

1. Definitions

A. Best Available Control Technology (BACT) means for any stationary source or modification the technology which gives the maximum degree of reduction of each air contaminant emitted from or resulting from such class or category of source which the Control Officer determines is achievable for such source. The Control Officer shall make this determination on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs. The Control Officer shall consider production processes and available methods, systems, and techniques for control of each such air contaminant, including fuel cleaning or treatment or innovative fuel combustion techniques.

In no event shall the emission rate reflected by the control technique or limitation exceed the amount allowable under applicable new source performance standards.

B. Lowest Achievable Emission Rate (LAER) means for any stationary source or modification the more stringent of:

1. The most effective emissions control technique which has been achieved in practice, for such class or category of source; or

2. The most effective emission limitation which the Federal Environmental Protection Agency certifies is contained in the implementation plan of any State approved under the Clean Air Act for such class or category of source, unless the owner or operator, of the proposed source demonstrates that such limitations are not achievable; or

3. The emission limitation specified for such class or category of source under applicable Federal new source performance standards pursuant to Section 111 of the Clean Air Act; or

4. Any other emissions control technique found, after public hearing, by the Control Officer or the Air Resources Board to be technologically feasible and cost effective for such class or category of sources or for a specific source.

C. Modeling means using an air quality simulation model, based on specified assumptions and data which has been approved in writing by the Executive Officer of the Air Resources Board.

D. Modification means any physical change in, change in method of operation of, or addition to an existing stationary source, except that routine maintenance or repair shall not be considered to be a physical change. A change in the method of operation, unless previously limited by an enforceable permit condition, shall not include:

1. An increase in the production rate, if such increase does not exceed the operating design capacity of the source.

2. An increase in the hours of operation.

3. Change in ownership of a source.

4. Any part or item of equipment used to replace an existing part or item of equipment, on the same property, which has failed, provided the applicant certifies in writing to the Control Officer that the replacement component is identical in all material respects to the component replaced and that the replacement will not result in an increase in emissions.

E. Precursor means a directly emitted air contaminant that, when released to the atmosphere, forms or causes to be formed or contributes to the formation of a secondary pollutant for which a national ambient air quality standard has been adopted or whose presence in the atmosphere will contribute to the violation of one or more national ambient air quality standard. The following precursor-secondary air contaminant relationships shall be used for the purposes of this rule.

PRECURSOR	SECONDARY AIR CONTAMINANT
Hydrocarbons and substituted hydrocarbons (Reactive organic gases)	a. Photochemical Oxidants (Ozone) b. The organic fraction of suspended particulate matter.
Nitrogen Oxides	a. Nitrogen dioxide b. The nitrate fraction of suspended particulate matter. c. Photochemical oxidant (ozone).
Sulfur Oxides	a. Sulfur dioxide b. Sulfates c. The sulfate fraction of suspended particulate matter.

F. Seasonal Source means any stationary source with more than 75 percent of its annual operating hours within a consecutive 90-day period.

G. Stationary Source includes any structure, building, facility, equipment, installation or operation (or aggregation thereof) which is owned, operated, or under shared entitlement to be used by the same person and which is located within the District on:

1. One property or on bordering properties; or

2. One or more properties wholly within either the Western Kern County Oil Fields or the Central Kern County Oil Fields and is used for the production of oil.

Items of air-contaminant-emitting equipment shall be considered aggregated into the same stationary source, and items of nonair-contaminant-emitting equipment shall be considered associated with air-contaminant emitting equipment only if:

1. The operation of each item of equipment is dependent upon, or affects the process of, the others; and

2. The operation of all such items of equipment involves a common raw material or product.

Emissions from all such aggregated items of air-contaminant-emitting equipment and all such associated items of nonair-contaminant-emitting equipment of a stationary source shall be considered emissions of the same stationary source.

H. Upwind area shall be bounded by a line drawn perpendicular to the predominant wind flow line passing through or nearest to the site of the new source or modification and extending to the boundaries of the same or adjoining counties within the same air basin except where the Control Officer determines that for reasons of topography or meteorology such a definition is inappropriate. The predominant wind flow lines used in this rule shall be those contained in Figure I. For sites located between diverging and converging wind flow lines, an interpolated line shall be constructed which bisects the distance between the applicable flow lines shown in Figure I.

I. Major Stationary Source is a stationary source which emits 200 pounds or more during any day of any air contaminant for which there is a national ambient air quality standard or any precursor of such contaminant.

J. National Ambient Air Quality Standard: All references in Rule 210.1 and 210.2 to national ambient air quality standards shall be interpreted to include state ambient air quality standards. (This subsection shall not be submitted or is it intended to be a part of the State Implementation Plan.)

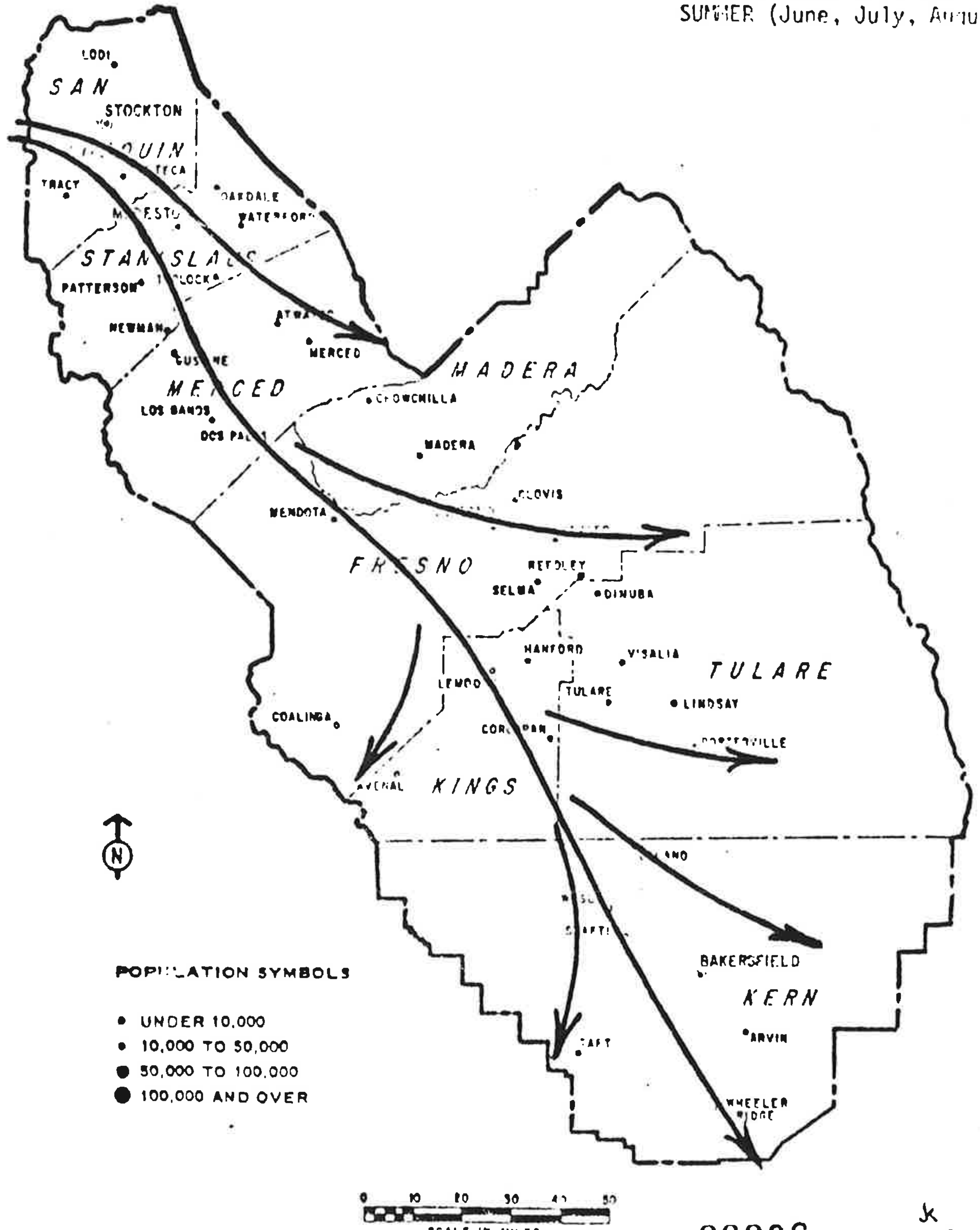
K. Point of maximum ground level impact means that area where the actual or projected air contaminant concentrations resulting from the new or modified stationary source are at the maximum level after including the effect of any control technology and mitigation employed.

L. Central Kern County Fields boundaries are described as:

Beginning at a point common to the northerly boundary line of Kern County and the line bearing in a southerly direction between Range 24E and Range 25E, MDB&M; thence south along said line between Range 24E and Range 25E to a point on the line between Township 28S and Township 29S, MDB&M; thence west along said line between Township 28S and Township 29S to a point on the line bearing in a southerly direction between Range 24E and Range 25E, MDB&M; thence

SAN JOAQUIN VALLEY
AIR BASIN

Figure I
PREDOMINANT WIND FLOW
SUMMER (June, July, August)



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south along said line between Range 24E and Range 25E to a point on the line between Township 32S, MDB&M, and Township 12N, SBB&M; thence east along said line between Township 32S and Township 12N to a point on the line between Range 22W and Range 23W, SBB&M, thence south along said line to a point on the line between Township 10N and Township 11N, SBB&M; thence east along said line between Township 10N and Township 11N to a point on the line between Range 20W and Range 21W, SBB&M; thence south along said line between Range 20W and Range 21W to a point on the line bearing in an easterly direction between Township 10N and Township 11N, SBB&M; thence east on said line between Township 10N and Township 11N to a point on the line between Range 17W and Range 18W, SBB&M; thence north along said line between Range 17W and Range 18W to a point on the line between Township 32S, MDB&M, and Township 12, SBB&M; thence east along said line between Township 32S and Township 12N to a point on the line between Range 30E and Range 31E, MDB&M; thence north along said line between Range 30E and Range 31E to a point on the line between Township 28S and Township 29S, MDB&M; thence east along said line between Township 28S and Township 29S to a point on the line bearing in a northly direction between Range 30E and Range 31E, MDB&M; thence north along said line between Range 30E and Range 31E to a point on the northerly boundary line of Kern County; thence west along said boundary to the point of beginning. (Figure 2)

M. Western Kern County Fields boundaries are described as:

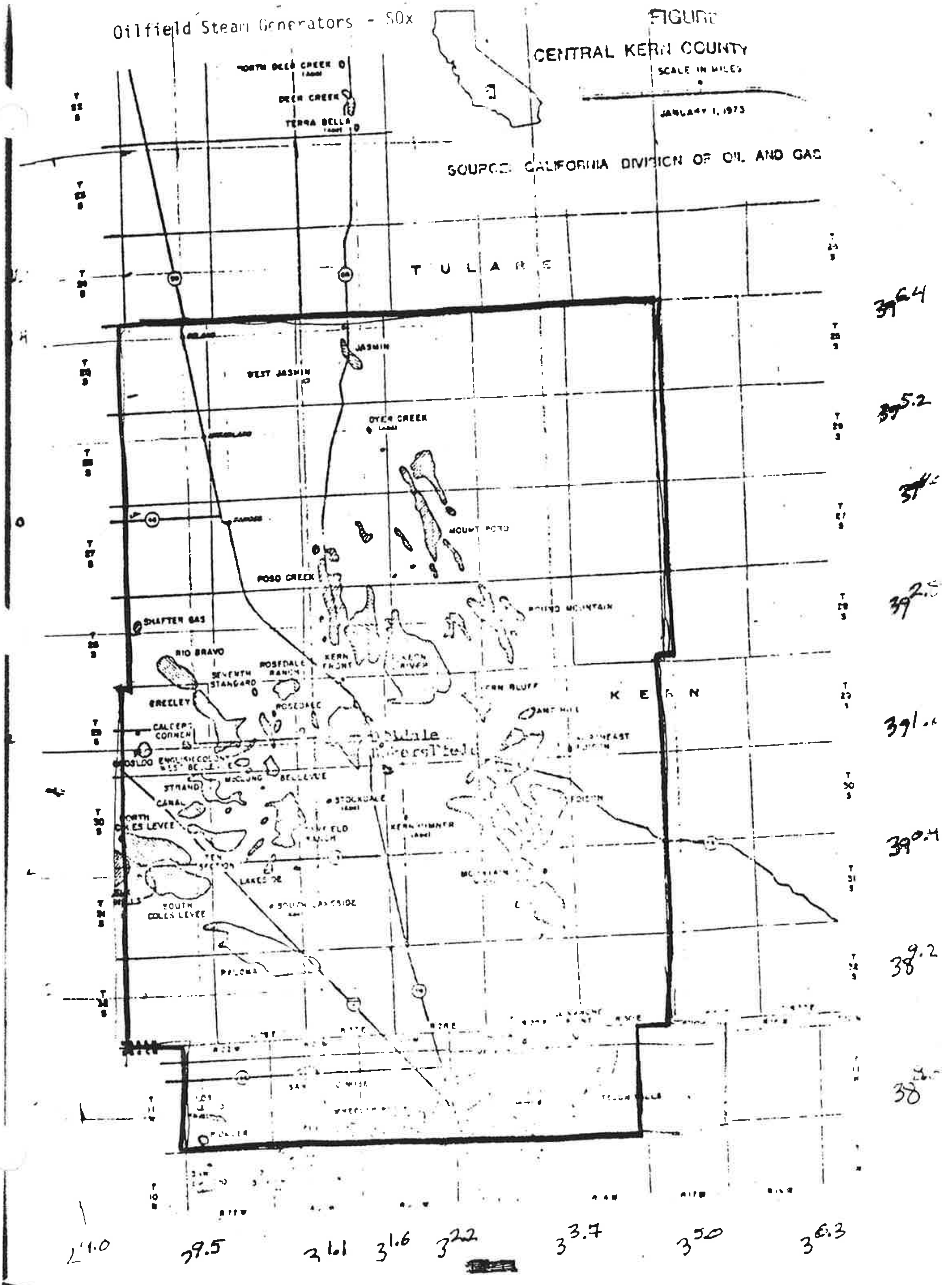
Beginning at a point common to the northerly boundary of Kern County and the line between Range 24E and 25E, MDB&M, and following the Kern County boundary in a westerly, then a southerly, and then easterly and southerly directions to a point common to the easterly County boundary and the line between Township 10N and Township 11N, SBB&M; thence easterly along said line between Township 10N and Township 11N to a point on the line between Range 22W and Range 23W, SBB&M; thence north along said line between Range 22W and Range 23W to a point on the line between Township 32S, MDB&M, and Township 12N, SBB&M; thence westerly along said line between Township 32S and Township 12N to a point on the line between Range 24E and Range 25E, MDB&M; thence north on said line between Range 24E and 25E to a point on the line between Township 28S and Township 29S, MDB&M; thence east along said line between Townships 28S and 29S to the point on the line bearing in a northerly direction between Range 24E and Range 25E, MDB&M; thence north along said line between Range 24E and 25E to the point of beginning. (Figure 3)

2. General

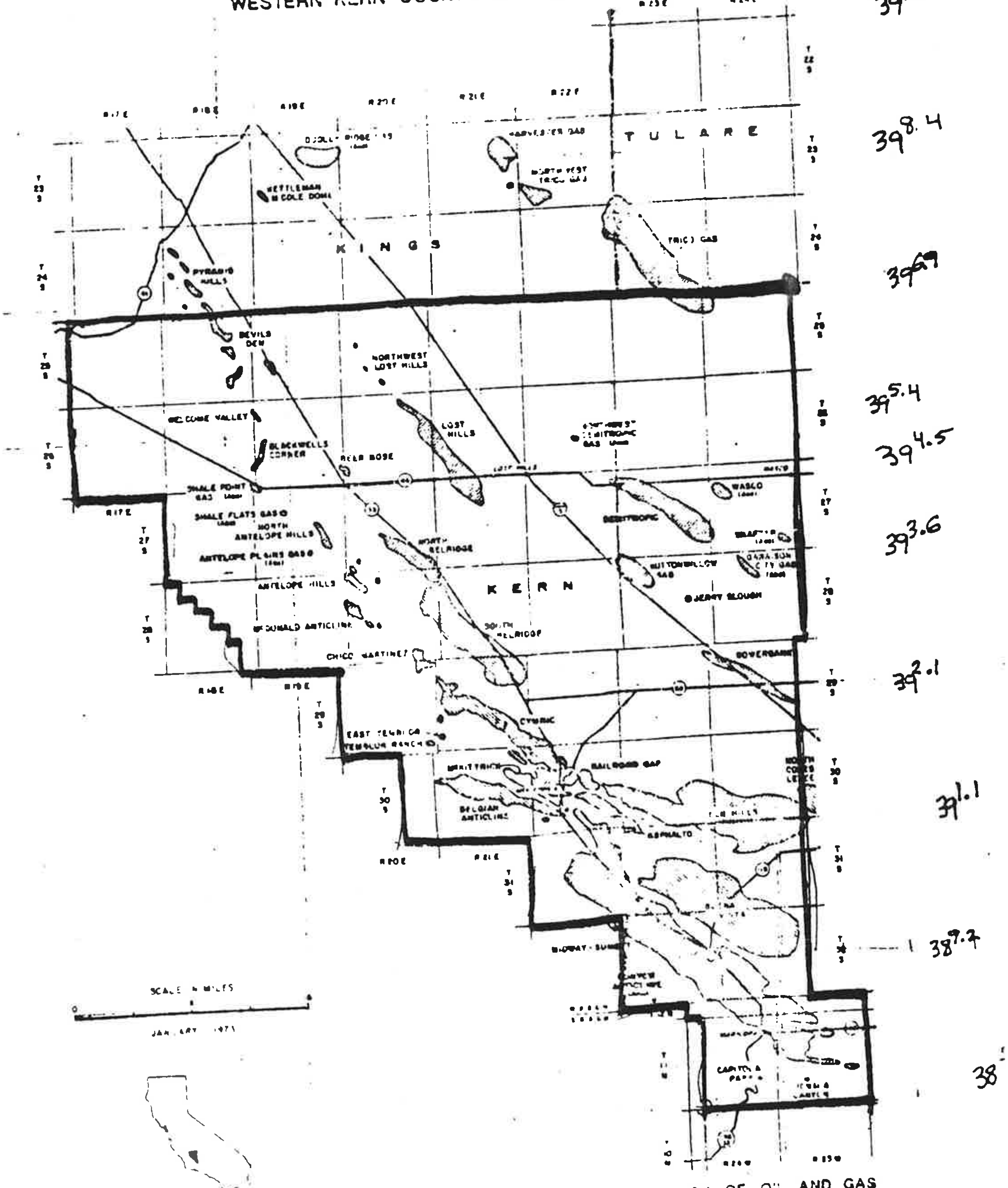
A. The Control Officer shall deny an Authority to Construct for any new stationary source or modification, or any portion thereof unless:

1. The new source or modification, or applicable portion thereof, complies with the provisions of this rule and all other applicable District rules and regulations; and

Oilfield Steam Generators - SOx



WESTERN KERN COUNTY OIL FIELDS with UTM COORDINATES



SOURCE: CALIFORNIA DIVISION OF OIL AND GAS

2^1.6 2^2.3 2^3.9 2^4.7 2^5.4 2^6.1 2^6.8 2^7.6 2^8.3

for all pollutants for which there is a national ambient air quality standard and all precursors of such pollutants. All sources applying for an Authority to Construct pursuant to this section shall be shown not to significantly impact Class I areas as specified in Part C of the Clean Air Act.

E. Notwithstanding the provisions of Section (3)(C), the Control Officer may exempt from Section (5)(B) any new source or modification:

1. Which will be used exclusively for providing essential public services, such as schools, hospitals, or police and fire fighting facilities, but specifically excluding sources of electrical power generation other than for emergency standby use at essential public service facilities.

2. Which is exclusively a modification to convert from use of a gaseous fuel to a liquid fuel because of a demonstrable shortage of gaseous fuels, provided the applicant establishes to the satisfaction of the Control Officer that it has made its best efforts to obtain sufficient emissions offsets pursuant to Section (5) of this rule, that such efforts had been unsuccessful as of the date the application was filed, and the applicant agrees to continue to seek the necessary emissions offsets until construction on the new stationary source or modification begins. This exemption shall only apply if, at the time the Permit to Operate was issued for the gas burning equipment, such equipment could have burned the liquid fuel without additional controls and been in compliance with all applicable district regulations.

3. Which is portable sandblasting equipment used on a temporary basis within the District.

4. Which uses innovative control equipment or processes which will likely result in a significantly lower emission rate from the stationary source than would have occurred with the use of previously recognized LAER, and which can be expected to serve as a model for technology to be applied to similar stationary sources within the state resulting in a substantial air quality benefit, provided the applicant establishes by modeling that the new stationary source or modification will not cause the violation of any national ambient air quality standard at the point of maximum ground level impact. This exemption shall apply only to air contaminants which are controlled by the innovative control equipment or processes. The Control Officer shall consult with the Executive Officer of the Air Resources Board prior to granting an exemption pursuant to this subsection.

5. Which consists solely of the installation of air pollution control equipment which, when in operation, will directly control emissions from an existing source.

2. For a major stationary source, the applicant certifies that all major stationary sources in the State that are owned or operated by the applicant are in compliance, or are on approved schedule for compliance, with all applicable emission limitations and standards under the Clean Air Act (42 USC 7401 et seq.) and all applicable emission limitations and standards which are part of the State Implementation Plan approved by the Environmental Protection Agency.

B. The Control Officer may issue an Authority to Construct for a new stationary source or modification which is subject to Section (5) only if all District regulations contained in the State Implementation Plan approved by the EPA are being carried out in accordance with that plan.

3. Applicability and Exemptions

A. This rule, excluding Section 5, shall apply to all new or modified stationary sources which are required pursuant to District rules to obtain an Authority to Construct.

This rule shall be effective September 12, 1979, and shall apply to all applications for Authority to Construct which are received after September 12, 1979, or which are pending on its adoption. However all applications reviewed under Rule 210.1, as adopted 12/28/76, and which prior to September 12, 1979, received a preliminary decision pursuant to Section (h) of that rule, shall not be subject to this provision.

B. Section 5A of this Rule shall apply to all new stationary sources or modifications which are to result in a net increase in emissions of 150 lbs or more during any day of any air contaminant for which there is a national ambient air quality standard (excluding carbon monoxide) or any precursor of such contaminant.

C. Sections 5B of this Rule shall apply to all new stationary sources or modifications which will result in either:

1. A net increase in emissions of 200 lbs or more during any day of any air contaminant for which there is a national ambient air quality standard (excluding carbon monoxide) or any precursor of such a contaminant; or

2. A net increase in carbon monoxide emissions which the Control Officer determines would cause the violation of any national ambient air quality standard for carbon monoxide at the point of maximum ground level impact.

D. The provisions of Part C of the Clean Air Act, as amended in 1977, and any regulations adopted pursuant to those provisions, shall not be applicable to any new stationary source or modification which receives and Authority to Construct pursuant to this rule, provided such source or modification complies with the requirements of Section (5)(B)(2)

6. Which wishes to construct in an area which has a lack of major industrial development or absence of significant industrial particulate emissions and low urbanized population as long as the source can comply with the BACT and applicable federal, state and District emission regulations; and the impact of the emissions plus emissions from other stationary sources in the vicinity of the proposed location, along with non-rural fugitive background, will not cause a violation of the national ambient air quality standards. This exemption shall apply only to particulate emissions.

F. This rule shall not apply to any air pollution control equipment for a specific pollutant, which when in operation, will reduce air contaminant emissions from the source operation provided that equipment does not increase emissions of another pollutant.

4. Calculation of Emissions

A. The maximum design capacity of a new stationary source or modification shall be used to determine the emissions from the new source or modification unless the applicant, as a condition to receiving Authorities to Construct and Permits to Operate such new source or modification, agrees to limitations on the operations of the new source or modification, in which event the limitations shall be used to establish the emissions from the new source or modification.

B. The emissions from an existing source shall be based on the specific limiting conditions set forth in the source's Authorities to Construct and Permits to Operate, and, where no such conditions are specified, or where no Authority to Construct is required, on the actual operating conditions of the existing source averaged over the three consecutive years immediately preceding the date of application, or such shorter period as may be applicable in cases where the existing source has not been in operation for three consecutive years, or is cyclic in nature. Where the operation of a specific source has been significantly reduced during the previous three years, the Air Pollution Control Officer may specify an averaging period or emission rate which he determines provides an equitable emission base. If violations of laws, rules, regulations, permit conditions, or orders of the District, the California Air Resources Board, or the Federal Environmental Protection Agency occurred during the period used to determine the operating conditions, then adjustments to the operating conditions shall be made to determine the emissions the existing source would have caused without such violations.

C. The net increase in emissions from new stationary sources and modifications which are not seasonal sources shall be determined using yearly emission profiles or equivalent method (as specified by the Control Officer) subject to consultation with the ARB Executive Officer. Yearly emissions profiles for an existing or proposed stationary source or modification shall be constructed by plotting the daily emissions from such source in descending order. A separate profile shall be constructed for each pollutant. The net increase in emissions from a modification to an existing source shall be determined by comparing the yearly emissions profiles for the existing source to the yearly emissions profiles for the proposed source after modification. A net increase in emissions exists whenever any part of an emissions profile for a modified source exceeds the emissions profile for the existing source.

D. The net increase in emissions from new stationary sources and modification which are seasonal sources shall be determined using yearly and quarterly emissions profiles, or equivalent method as specified by the Air Pollution Control Officer, subject to consultation with the ARB Executive Officer. Quarterly emissions profiles shall be constructed by plotting the daily emissions from an existing or proposed seasonal facility in descending order for the continuous 90 day period during which the greatest emissions from the proposed new or modified source will occur. A separate profile shall be constructed for each pollutant. The net increase in emissions from the modification to an existing seasonal source shall be determined by comparing the yearly and quarterly emissions profiles for the existing source to the yearly and quarterly emissions profiles for the proposed source after modification. A net increase in emissions exists whenever any part of an emissions profile for the modified source exceeds the emissions profile for the existing source.

E. When computing the net increase in emissions for modifications, other th modifications to heavy oil production operations, the Control Officer sh take into account the cumulative net emissions changes which were achiev after December 28, 1976, and which are represented by Authority to Const or Permit to Operate issued to the stationary source excluding any emiss reductions required to comply with any federal, state or district law, r order or regulation. When computing the net increase in emissions for modifications to heavy oil production operations, the Control Officer shall take into account the cumulative net emissions changes represented by Authority to Construct issued to the stationary source after Septemb 12, 1979, excluding any emissions reduction required to comply with any federal, state, or district law, rule, order, or regulations, except Rule 425. Emissions resulting from implementation of Rule 425 shall be taken into account in accordance with the requirements of Rule 425.

Added 3/6/80 by CARB

5. Control Technology and Mitigation Requirements

A. Best Available Control Technology (BACT)

All new stationary sources and modifications subject to this section shall be constructed using BACT for such net air contaminant increases as specified in Section 3.B.

B. Lowest Achievable Emission Rate (LAER) and Mitigation

1. All new stationary sources and modifications subject to this section shall be constructed using LAER, and mitigation shall be required for such net emission increases (i.e. increases after the application of LAER) as specified in Section 3.C.

a. of such air contaminant(s) for which a national ambient air quality standard was exceeded within the air basin more than three discontinuous times within the three years immediately preceding the date when the application for the Authority to Construct was filed, and for all precursors of such air contaminants; provided, however, that mitigation of net emission increases of sulfur oxides, total suspended particulates, oxides of nitrogen or carbon monoxide shall not be required if the applicant demonstrates through modeling that emissions from the new source or modification will not cause a new violation of any national ambient air quality standard for such air contaminants, or make any existing violation of any such standard worse, at the point of maximum ground level impact.

b. not subject to Subsection (a) but which the Control Officer determines would cause a new violation of any national ambient air quality standard, or would make any existing violation of any such standard worse, at the point of maximum ground level impact. Emissions reductions required as a result of this subsection must be shown through modeling to preclude the new, or further worsening of any existing, violation of any national ambient air quality standard that would otherwise result from the operation of the new source or modification, unless such reductions satisfy the requirements of Section (5)(B)(2).

2. Net emissions increases subject to Section (5)(B)(1)(a) shall be mitigated (offset) by reduced emissions from existing stationary or nonstationary sources. Emissions reductions shall be sufficient to offset any net emission increase and shall take effect at the time, or before, initial operation, of the new source, or within 90 days after initial operation of a modification.

3. Emissions offset profiles or equivalent method, as specified by the Air Pollution Control Officer, subject to consultation with the ARB Executive Officer, shall be used to determine whether proposed offsets mitigate the net emissions increases from proposed new sources or modifications.

a. For all offset sources, a yearly emissions offset profile shall be constructed in a manner similar to that used to construct the yearly emissions profile for the proposed new or modified source. Daily emissions reductions which will result from the further control of such sources shall be plotted in descending order. A separate profile shall be constructed for each pollutant. Seasonal offsets shall not be used to mitigate the emissions from nonseasonal sources.

b. In addition, for seasonal offset sources, a quarterly emissions offset profile shall be constructed for the same time period and in the same manner as that used to construct the quarterly emissions profile for the proposed new or modified source. Daily emissions reductions which will result from further control of existing sources shall be plotted on the quarterly offset profile in descending order. A separate profile (which may cover different months) shall be plotted for each pollutant.

c. Adjusted emissions offset profiles shall be constructed by dividing each entry used in the construction of the emissions offset profiles by the offset ratio determined in Subsection (d).

d. The adjusted emissions offset profiles shall be compared with the emissions profiles to determine whether net emissions increases have been mitigated at all points on the profiles.

4. A ratio of emissions offsets to emissions (offset ratio) for new sources or modifications, other than heavy oil production operations, of 1.2:1 shall be required for emissions offsets located either:

   i. upwind in the same or adjoining counties; or

   ii. within a 15 mile radius of the proposed new source or modification. For emissions offsets located outside of the areas described above, the applicant shall conduct modeling to determine an offset ratio sufficient to show a net air quality benefit in the area affected by emissions from the new source or modification.

   b. Emissions from heavy oil production operations shall be offset by a ratio of:

      i. 1.0:1 if the emissions used as offsets are owned by the same company and located within the same stationary source which is to be modified:

      ii. 1.2:1 if the emissions used as offsets from different companies are located within the same oil field (Western Kern County Fields or Central Kern County Fields as defined in this rule) as the proposed new stationary source or modification;

      iii. 1.5:1 if the emissions used as offsets are located outside of the oil field (Western Kern County Fields or Central Kern County Fields as defined in this rule) in which the proposed new stationary source or modification is located, regardless of whether they are owned by the same or different companies.

      Notwithstanding any other provisions of this section the yearly emissions profiles, and the yearly emissions offset profiles for a source ~~object~~ subject to this section may be constructed based on the daily emissions from the source averaged on a monthly basis. In such event, an offset ratio of 2.0:1 shall be required.

5. If an applicant certifies that the proposed new source or modification is a replacement for a source which was shut down or curtailed after December 28, 1976, emissions reductions associated with such shutdown or curtailment may be used as offsets for the proposed source, subject to the other provisions of this section.

Sources which were shut down or curtailed prior to December 28, 1976, may be used to offset emissions increases for the replacement for such sources, subject to the other provisions of this section provided:

a. the shutdown or curtailment was made in good faith pursuant to an established plan approved by the Control Officer for replacement and emission control, and in reliance on air pollution laws, rules and regulations applicable at the time; and

b. the applicant demonstrates to the satisfaction of the Control Officer that there was good cause (which may include business or economic conditions) for delay in construction of the replacement facilities.

6. Notwithstanding any other provisions of this section any emissions reductions not otherwise authorized by this rule may be used as offsets of emissions increases from the proposed source provided the applicant demonstrates that such reductions will result in a net air quality benefit in the area affected by emissions from the new source or modification; the Control Officer shall consult with the Executive Officer of the Air Resources Board prior to granting such reduction.

7. Emissions reductions resulting from measures required by adopted federal, state, or district laws, rules or regulations shall not be allowed as emissions offsets unless a complete application incorporating such offsets was filed with the District prior to the date of adoption of the laws, rules or regulations, with the exception of Rule 425. Emission reductions resulting from implementation of Rule 425 shall be used in accordance with the provisions in that rule.

8. The Control Officer shall allow emissions reductions which exceed those required by this rule for a new source or modification to be banked for use in the future by the applicant. All such reductions, when used as offsets for the increased emissions from a proposed new source or modifications, shall be used in accordance with the other provisions of this Section.

9. Emission reductions achieved by the stationary source prior to the establishment of the District's banking system shall be used only for determining the net cumulative changes of emissions from that source. Such emission reductions, as well as emission reductions achieved on or after the establishment of the banking system pursuant to Health and Safety Code Sections 40709-40713, shall be allowed to be banked and transferred according to the requirements of the system.

10. For all power plants subject to Section 8, the applicant may, upon written notice to the Control Officer and the Executive Officer of the Air Resources Board, establish an emissions offset bank for a specific power plant at a specific location. The emissions offset bank shall be established no earlier than the date the applicant's Notice of Intention for the power plant is accepted by the California Energy Commission. The emissions offset bank shall lapse if the Commission rejects the applicable power plant or site; however, in such case the applicant may transfer the emissions offsets contained in the bank to another power plant and location for which the Commission has accepted a Notice of Intention. Emissions offsets may be deposited in the bank only by the applicant to construct the power plant, and all emissions offsets contained in the bank shall be used in accordance with Section (5)(B).

11. If an applicant for a resource recovery project using municipal waste demonstrates to the satisfaction of the Control Officer that the most likely alternative for treating such waste would result in an increase in emissions allowed under existing district permits and regulations, those emissions increases which would not occur as a result of the resource recovery project may be used to offset any net emissions increase from the resource recovery project in accordance with the other provisions of this section.

12. Emissions reductions of one precursor may be used to offset emissions increases of another precursor of the same secondary air contaminant provided the applicant demonstrates to the satisfaction of the Control Officer that the net emissions increase of the latter secondary precursor will not cause a new violation, or contribute to an existing violation, of any national ambient air quality standard at the point of maximum ground level impact. The ratio of the emission reductions between precursor pollutants of the same secondary air contaminant shall be determined by the Control Officer based on existing air quality data after consultation with the Executive Officer of the Air Resources Board.

6. Permit Condition Requirements for Offsets

The Control Officer shall, as a condition for the issuance of an Authority to Construct for a new stationary source modification and with the prior written consent of the owner or operator of any source which provides offsets:

A. Require that the new source or modification and any new sources which provide offsets shall be operated in the manner assumed in making the analysis required to determine compliance with this rule.

B. Modify, or require modification of, the Permit to Operate for any source used to provide offsets to ensure that emissions reductions at that source which provide offsets will be enforceable and shall continue for the reasonably expected useful life of the proposed source. If offsets are obtained from a source for which there is no Permit to Operate, a written contract shall be required between the applicant and the owner or operator of such source which contract, by its terms, shall be enforceable by the Control Officer to ensure that such reductions will continue for the reasonably expected useful life of the proposed source.

Such modification does not have to take effect until the new modified source, subject to this rule, commences operation.

C. Permit any other reasonably enforceable methods, other than those described in Subsections (A) and (B) which the Control Officer is satisfied will assure that all required offsets are achieved.

7. Analysis, Notice, and Reporting

A. The Air Pollution Control Officer shall determine whether the application is complete not later than 30 calendar days after receipt of the application, or after such longer time as both the applicant and the Air Pollution Control Officer may agree. Such determination shall be transmitted in writing immediately to the applicant at the address indicated on the application. If the application is determined to be incomplete, the determination shall specify which parts of the application are incomplete and how they can be made complete. Upon receipt by the Air Pollution Control Officer of any resubmittal of the application, a new 30-day period in which the Air Pollution Control Officer must determine completeness shall begin. Completeness of an application or resubmitted application shall be evaluated on the basis of the requirements set forth in (district regulations adopted pursuant to AB 884 regarding information requirements) as it exists on the date on which the application or resubmitted application was received. After the Air Pollution Control Officer accepts an application as complete, the Air Pollution Control Officer shall not subsequently request of an applicant any new or additional information which was not specified in the Air Pollution Control Officer's list of items to be included within such applications. However, the Air Pollution Control Officer may, during the processing of the application, request an applicant to clarify, amplify, correct, or otherwise supplement the information required in such list in effect at the time the complete application was received. Making any such request does not waive, extend, or delay the time limits in this rule for decision on the completed application, except as the applicant and Air Pollution Control Officer may both agree.

B. Following acceptance of an application as complete the Air Pollution Control Officer shall:

1. Perform the evaluations required to determine compliance with this rule and make a preliminary written decision as to whether a permit to construct should be approved, conditionally approved, or disapproved. The decision shall be supported by a succinct written analysis.

2. Within 10 calendar days following such decision, publish a notice of prominent advertisement in at least one newspaper of general circulation in the District stating the preliminary decision of the Air Pollution Control Officer and where the public may inspect the information required to be made available under Subsection (3). The notice shall provide 30 days from the date of publication for the public to submit written comments on the preliminary decision.

3. At the time notice of the preliminary decision is published, make available for public inspection at the Air Pollution Control District's office the information submitted by the applicant, the Air Pollution Control Officer's supporting analysis for the preliminary decision, and the preliminary decision to grant or deny the permit to construct, including any proposed permit conditions, and the reasons therefor. The confidentiality of trade secrets shall be considered in accordance with Section 6254.7 of the Government Code and relevant sections of the Administrative Code of the State of California.

4. No later than the date of publication of the notice required by Subsection (2), forward the analysis, the preliminary decision, and copies of the notice to the Air Resources Board (attn: Chief, Stationary Source Control Division) and the Regional Office of the U.S. Environmental Protection Agency.

5. Consider all written comments submitted during the 30 day public comment period.

6. Within 180 days after acceptance of the application is complete, take final action on the application after considering all written comments. The Air Pollution Control Officer shall provide written notice of the final action to the applicant, the Environmental Protection Agency, and the California Air Resources Board, shall publish such notice in a newspaper of general circulation, and shall make the notice and all supporting documents available for public inspection at the Air Pollution Control District's office.

C. The public notice and reporting requirements set forth in Subsections (B)(2) through (B)(6) shall not be required for any permit which does not include conditions requiring the control of emissions from an existing source.

8. Power Plants

This section shall apply to all power plants proposed to be constructed in the District and for which a Notice of Intention (NOI) or Application for Certification (AFC) has been accepted by the California Energy Commission. The Control Officer, pursuant to Section 25538 of the Public Resources Code, may apply for reimbursement of all costs, including lost fees, incurred in order to comply with the provisions of this section.

A. Within fourteen days of receipt of an NOI, the Control Officer shall notify the Air Resources Board and the Commission of the District's intent to participate in the NOI proceeding. If the District chooses to participate in the NOI proceeding, the Control Officer shall prepare and submit a report to the Air Resources Board and the Commission prior to the conclusion of the nonadjudicatory hearings specified in Section 25509.5 of the Public Resources Code. That report shall include, at a minimum:

1. a preliminary specific definition of BACT and LAER for the proposed facility;

2. a preliminary discussion of whether there is substantial likelihood that the requirements of this rule and all other District regulations can be satisfied by the proposed facility;

3. a preliminary list of conditions which the proposed facility must meet in order to comply with this rule or any other applicable District regulation.

The preliminary determinations contained in the report shall be as specific as possible within the constraints of the information contained in the NOI.

B. Upon receipt of an AFC for a power plant, the Control Officer shall conduct a Determination of Compliance review. This Determination shall consist of a review identical to that which would be performed if an application for an Authority to Construct had been received for the power plant. If the information contained in the AFC does not meet the District's established requirements for permit applications, the Control Officer shall, within 20 calendar days of receipt of the AFC, so inform the Commission, and the AFC shall be considered incomplete and returned to the applicant for resubmittal.

C. The Control Officer shall consider the AFC to be equivalent to an application for an Authority to Construct during the Determination of Compliance review, and shall apply all provisions of this rule which apply to applications for an Authority to Construct.

D. The Control Officer may request from the applicant any information necessary for the completion of the Determination of Compliance review. If the Control Officer is unable to obtain the information, the Control Officer may petition the presiding Commissioner for an order directing the applicant to supply such information.

E. Within 180 days of accepting an AFC as complete, the Control Officer shall make a preliminary decision on:

1. whether the proposed power plant meets the requirements of this rule and all other applicable district regulations; and

2. in the event of compliance, what permit conditions will be required including the specific BACT and LAER requirements and a description of required mitigation measures.

F. The preliminary written decision made under Subsection (E) shall be treated as a preliminary decision under Subsection (7)(A)(1) of this rule, and shall be finalized by the Control Officer only after being subject to the public notice and comment requirements of Section (7). The Control Officer shall not issue a Determination of Compliance unless all requirements ot this rule are met.

G. Within 240 days of the filing date, the Control Officer shall issue and submit to the Commission a Determination of Compliance or, if such a determination cannot be issued, shall so inform the Commission. A Determination of Compliance shall confer the same rights and privileges as a permit to construct only when and if the Commission approves the AFC, and the Commission certificate includes all conditions of the Determination of Compliance.

H. Any applicant receiving a certificate from the Commission pursuant to this section and in compliance with all conditions by the certificate shall be issued a Permit to Operate by the Control Officer.

9. Severability

If any portion of this rule is found to be unenforceable, such finding shall have no effect on the enforceability of the remaining portions of the rule, which shall continue to be in full force and effect.

Exhibit G

orig → File PFA-1 cc, Wright HCB

KERN COUNTY AIR POLLUTION CONTROL DISTRICT

1601 "H" Street, Suite 250
akersfield, California 93301-5199
Telephone: (805) 861-3682

LEON M HEBERTSON, M.D
Director of Public Health
Air Pollution Control Officer

November 10, 1983

Mr. David P. Howekamp, Director
Air Management Division
U.S. E.P.A. Region IX
215 Fremont Street
San Francisco, CA 94105

Dear Mr. Howekamp:

Thank you for your letter of November 7, 1983 in which you expressed concern over the manner in which the District has interpreted our Rule 210.1, Sections 5.B.5 and 5.B.9 with regard to the pending Frito-Lay project. These same concerns were identified by District staff during preliminary discussions with the Frito-Lay in the spring of 1982. Based on discussions and correspondence with the applicant and his legal counsel, the new source was deemed to be a replacement for an existing source which was shut down after 12/28/76. Therefore, according to section 5.B.5 such reductions "may be used as offsets for the proposed source." Additionally, the District determined that section 5.B.9 only relates to the manner in which on-site reductions may be stored over time, and not to the transfer of emission reductions in an offset transaction. This position was adequately summarized by the law offices of Pillsbury, Madison & Sutro in a letter to Dr. Hebertson on July 26, 1982. (attached)

1. The District is also concerned that the 1982 ozone NAP accurately reflects sources of emissions. Consequently, procedures have been implemented to insure that Continental Carbon's emissions will remain in the inventory - perhaps under the name of "The Food Company" or Frito-Lay.

2. Eventhough the permit exempt equipment in this project may result in NO_x emissions of approximately 50% of the non-exempt equipment, such exempt emissions may not be included in our NSR analysis because they are not subject to Rule 210.1 requirements.

3. The District has added a condition requiring daily inspection of all fabric filters and repairs as needed.

4. The District is confident that an independent assessment of this project has been conducted. However, minor wording changes have been made to the Districts analysis to allay E.P.A.'s concern.

5. Unfortunately, a mechanism does not exist by which the District may extend the 30 day public comment period specified in Rule 210.1. We regret that this time limit did not allow your staff sufficient time to review the regulatory concerns associated with this project and every effort will be made to provide E.P.A. with copies of our analyses as quickly as possible.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Citron Toy

Citron Toy
Chief Air Sanitation Officer

CT/dl

Exhibit H

10 APR 1984

Dr. Leon M. Hebertson
Air Pollution Control Officer
Kern County Air Pollution
  Control District
1601 H Street, Suite 250
Bakersfield, CA 93301

Dear Dr. Hebertson:

As a follow-up to our joint meeting with Frito-Lay on April 4, I want to provide a final resolution to the federal issues we have identified in our review of the Kern County permit for this source.

I understand that Frito-Lay and the Continental Carbon Corporation (CCC) acted in good faith under the assumption that both federal regulations and the Kern County NSR rule allowed use of CCC's permitted emissions as offsets for Frito-Lay's project, including the expansion of the project as identified in the EIR. In view of this good faith reliance, EPA will not now require that the permit be revised to conform to national regulations and the approved State Implementation Plan requirements. Furthermore, it does not seem equitable to Frito-Lay to prevent use of the CCC emissions as offsets for a future expansion integral to the project. We do agree with you, however, that CCC emissions and Permits to Operate can only be used by Frito-Lay for the snack foods processing plant at their present site and may not be sold or traded.

I want to reiterate our position regarding the federal restrictions on prior shutdown offsets credits and I ask from you a written commitment to follow this restriction in all future cases until federal regulations change. As we have pointed out in several previous letters and discussions with your staff, we find the provisions of 40 CFR 51.19(j)(iii)(2)(c) prevent use of prior shutdowns as offset credit except for an onsite replacement. In addition, the calculation of credits from a shutdown cannot be based on permitted emissions but must be based on actual emissions (i.e., the average rate at which the unit actually emitted during a two year period immediately preceding the shutdown). EPA expects that the District's commitment to these requirements will prevent any future misunderstandings.

As you indicated, we can avoid repetition of the confusion over the CCC/Frito-Lay trade and permit through early discussions regarding the relevant national restrictions on offsets and trades. We share fully your concern that permit applicants be informed and thus, if possible, avoid purchasing expensive offsets which are invalid for the intended purposes. Please contact us at the earliest moment if you have questions regarding federal regulations: I commit to providing guidance promptly.

Sincerely,

Original Signed By:
David P. Howekamp

David P. Howekamp
Director
Air Management Division

cc: Gordon Duffy, ARB
Harmon Wong-Woo, ARB
Edward Reap, Frito-Lay

Exhibit I

RECEIVED

APR 20 1992

KERN COUNTY AIR
POLLUTION CONTROL DISTRICT

Frito-Lay, Inc.

Code No. ____
BY ORDER OF THE BD/SUPV
referred to
APCD

copies furnished:
Each Supervisor and CAO

Filed by BD/Supv. 4/16/92
SUE LASITER, Clerk
of the Board of Supervisors
By: A. Johnson

April 13, 1992 92 APR 16 AM 11:24

Mr. David L. Crow
Executive Director/APCO
San Joaquin Valley Unified
Air Pollution Control District
2314 Mariposa Street, #100
Fresno, California 93715

KERN CO. CLERK OF SUPERVISORS DEPUTY

**RE: Frito-Lay, Inc., Kern Production Facility
Emission Reduction Banking Certificate**

Dear Mr. Crow:

In accordance with the direction of Thomas Goff of your staff, attached is the resubmittal of Frito-Lay's Application for an Emission Reduction Banking Certificate, previously transmitted on March 17, 1992. Pursuant to Mr. Goff's direction, I have also provided a discussion supporting the issuance of the requested Emission Reduction Banking Certificate and enclosed copies of the supporting documentation. Frito-Lay believes that the supporting documentation constitutes the required "District recognition" and clearly indicates that the subject emission reduction credits have undergone rigorous, regulatory review, consistent with current review standards, as these credits were intended to be treated the same as banked emissions. This was the original concept as reflected in District correspondence, dated November 12, 1987 and later reaffirmed in correspondence to USEPA, Region IX, dated July 24, 1991.

As explained in the March 17, 1992 submittal, almost ten years ago, Frito-Lay acquired emission reductions from Continental Carbon (owner of a carbon black facility located west of Bakersfield) to allow for the location of a new snack food production facility and regional warehouse in Kern County. At the time these emission reductions occurred, there was no banking rule in Kern County. As further explained in the March 17 submittal, these reductions were formally recognized in writing by the District (prior to the County's adoption of a banking rule which occurred on April 27, 1983) as available for offsets (ref. enclosed correspondence from T. Paxson, dated February 25, 1983). During the final approval of the Authorities to Construct for Phase I development of Frito-Lay's Kern County production complex, additional recognition of these reductions was provided in correspondence from the District and from the Region IX office of the USEPA (ref. enclosed correspondence dated 11/10/83 and 4/10/84).

We have obtained the concurrence of expert legal counsel that this written recognition by the District entitles Frito-Lay to an Emission Reduction Banking Certificate pursuant to Rule 230.1, the Emission Reduction Credit Banking Rule of the San Joaquin Valley Unified APCD. Rule 230.1 at IV A.2. specifically provides that emission reductions occurring prior to January 1, 1988 "for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets shall be eligible for emissions reductions banking certificates...".

As Kern County did not have a banking rule at the time the emission reductions became available, Frito-Lay is entitled to a banking certificate in accordance with the literal interpretation of the rule. Briefly, this interpretation of the language of the rule provides that if a given county did not have a banking rule in effect when pre-1988 emission reductions became available, then the formal, written recognition of such reductions by the District will be recognized.

Mr. David L. Crow
April 13, 1992
Page Two

The language of the rule clearly delineates between pre-1988 emission reductions, those occurring prior to and those after a banking rule. The key issue raised by Rule 230.1 is what legal mechanism was in place to recognize emission reduction credits at the time these credits were originally recognized by the District as available for offsets. If the District at the time had a banking rule, then conformance to this rule would have been required. On the other hand, if no rule existed when the credits became available, as was the scenario with Frito-Lay's emission reductions, then the formal, written recognition from the District was the only mechanism available to identify and preserve credits for use as offsets.

Enclosed is the documentation that the emission reductions represented in the attached Application were formally recognized in writing by the District (on several occasions) as available for offsets at a time when Kern County had no banking rule. Documentation which supports the quantity of emission reduction credits available to Frito-Lay is also enclosed.

In addition to Frito-Lay's strong legal entitlement to a banking certificate based on the language of Rule 230.1, it also has a strong equitable position. After the adoption of the banking rule in Kern County, Frito-Lay sought to have the already recognized emission reductions added to the bank(ref. enclosed correspondence from M.Barr to L.Hebertson, dated 12/21/87). The District determined that it would prefer to continue preserving the credits in valid Permits to Operate, which Frito-Lay has kept current through annual fee payments.

We are eager to resolve the current confusion and secure the banking certificate for the emission reductions held by Frito-Lay. This certificate is vital to our immediate and long term expansion plans for the Kern facility. We would be available to meet with you and your staff to aid in expediting the issuance of the Emission Reduction Banking Certificate for Frito-Lay.

Sincerely,
FRITO-LAY, INC.

HC Bradbury

H.C. Bradbury
Group Manager
Environmental Policy and Affairs

Attachment
Enclosure

cc: Pauline Larwood
Carl Hettinger
Seyed Sadredin
Thomas Goff
Robert T. Stewart, Esq.

Exhibit J

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office • 2700 M St., Suite 275 • Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-1

Issued To: **FRITO-LAY, INC.**
March 1, 1993

CONSUMED BY
S-156-1
9/24/93
RLY

Location of Reduction: **20807 Stockdale Highway**
Bakersfield
Sec 14, T32S, R23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
229,968 lbs	232,523 lbs	235,078 lbs	235,078 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: ______________________

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-1

CONDITIONS:

1. Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-2

Issued To: FRITO-LAY, INC.
March 1, 1993

Consumed By
S-156-2 9/24/93
PLY

Location of Reduction: 20807 Stockdale Highway
Bakersfield
Sec 14, T32S, R23E

For NOx Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
18,702 lbs	18,910 lbs	19,118 lbs	19,118 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: ____________________

David L. Crow, APCO

Seyed Sadredin
Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-2

CONDITIONS:

1. **Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.**

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-3

Issued To: FRITO-LAY, INC.
March 1, 1993

CONSUMED BY
S-156-3 9/24/98
RM

Location of Reduction: 20807 Stockdale Highway
Bakersfield
Sec 14, T32S, R23E

For CO Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
90,000 lbs	91,000 lbs	92,000 lbs	92,000 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: ______

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-3

CONDITIONS:

1. Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-4

Issued To: FRITO-LAY, INC.
March 1, 1993

CONSUMED BY
S-156-4 9/24/98
PhY

Location of Reduction: 20807 Stockdale Highway
Bakersfield
Sec 14, T32S, R23E

For PM10 Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
24,975 lbs	25,252 lbs	25,530 lbs	25,530 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: ____________________

David L. Crow, APCO

Seyed Sadredin
Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

EMISSION REDUCTION CREDIT CERTIFICATE S-0047-4

CONDITIONS:

1. Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.

San Joaquin Valley
Unified Air Pollution Control District

COPY

Southern Regional Office • 2700 M St., Suite 275 • Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-0047-5

Issued To: FRITO-LAY, INC.
March 1, 1993

Consumed By
S-156-5 9/24/93

Location of Reduction: 20807 Stockdale Highway
Bakersfield
Sec 14, T32S, R23E

For SO2 Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
161,703 lbs	161,500 lbs	165,296 lbs	165,296 lbs

[x] Conditions Attached

Method Of Reduction
[x] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Unit
[ ] Other: ______________________

David L. Crow, APCO

Seyed Sadredin
Director of Permit Services

Printed on Recycled Paper.

CONDITIONS:

1. Per Rule 2201 4.2.5.1, these reductions may not be used as offsets for emissions from a major source or major modification. Due to previous agreements regarding these reductions this prohibition does not apply to the use of these reductions as offsets for the Frito-Lay snack food facility located at 22801 Highway 58.

Exhibit K

Fwd: ERC Project S-1011223

Inbox x

Print all

David Abell <david.abell@sierraclub.org> 9:02 AM (0 minutes ago)

to me

---------- Forwarded message ----------
From: **Homero Ramirez** <Homero.Ramirez@valleyair.org>
Date: Tue, May 21, 2013 at 1:01 PM
Subject: ERC Project S-1011223
To: "petra.pless@gmail.com" <petra.pless@gmail.com>

Petra:

Here is the copy of the evaluation (and ERC certificates) for project S-1011223, the ERC transfer in which I noted that the special use provision was removed for the certificates.

Homero

From: Homero Ramirez
Sent: Tuesday, May 21, 2013 12:58 PM
To: 'petra.pless@gmail.com'
Subject: ERC Project S-1000991

Hi Petra.

Per our telephone conversation, attached is a copy of the evaluation (and ERC certificates) for project S-1000991 for transfer of ERCs from Frito Lay to Oceanair. I will send you the information for the other project in a separate email.

If you have any questions, please contact me.

Homero Ramirez
San Joaquin Valley Air Pollution Control District
34946 Flyover Court
Bakersfield, CA 93308
Tel. (661) 392-5616
Fax (661) 392-5585

3 attachments — Download all attachments

673325.pdf
37K View Download

673324.pdf
43K View Download

673329.pdf
45K View Download

Click here to Reply or Forward

ERC TRANSFER OF OWNERSHIP REVIEW

Facility Name:	OceanAir Environmental, LLC
Mailing Address:	4220 Donlon Road Somis, CA 93066
Contact Name:	Mahesh Talwar, President
Telephone:	(805) 386-1882
Engineer:	Steve Tomlin
Date:	December 6, 2001
Lead Engineer:	Leonard Scandura, Supervising Air Quality Engineer LMS
Date:	12/7/01
Project:	1011223
ERC # Tendered:	S-1474-1
New ERC #s:	S-1700-1
Received:	December 3, 2001

I. PROPOSAL:

Ocean Air Environmental is requesting a transfer of ownership of an Emission Reduction Credit Certificate (ERC) to Duke Energy Avenal LLC. Ocean Air has submitted a letter releasing the ownership of the entire certificate to Duke Energy.

Old Ocean Air Environmental ERC Number	New Duke Energy Avenal ERC Number
S-1474-1	S-1700-1

II. APPLICABLE RULES:

Rule 2301 Emission Reduction Credit Banking (12/17/92)

III. COMPLIANCE REVIEW:

Rule 2301 Emission Reduction Credit Banking (12/17/92)

Ocean Air Environmental has filed to transfer ownership of Emission Reduction Credit (ERC) certificates in accordance with Rule 2301, section 7.2, and has submitted a written statement designating Duke Energy as the new owner of the certificate. Compliance is expected.

IV. RECOMMENDATION:

Issue ERC banking certificate S-1700-1 in the following allotments and as shown on the draft banking certificate.

Certificate Allotment:

ERC Certificate Reissue Amounts, lbs

	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
ERC S-1700-1,VOC	87,500	87,500	87,500	87,500

V. BILLING INFORMATION:

The applicant has paid $60 for processing the transfer of ownership of one ERC certificate. No other processing fees are required; therefore, additional billing is not required at this time.

San Joaquin Valley
Air Pollution Control District
Southern Regional Office * 2700 M St., Suite 275 * Bakersfield, CA 93301

Emission Reduction Credit Certificate
S-1474-1

T & O
to Duke
Energy Avenal LLC
as S-1700-1
12-18-01
SVT

ISSUED TO: Ocean Air Environmental

ISSUED DATE: October 16, 2000

LOCATION OF REDUCTION: 20807 Stockdale Highway
Bakersfield, CA
Section 14, Township 32S, Range 23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
87,500 lbs.	87,500 lbs.	87,500 lbs.	87,500 lbs.

[ ] Conditions Attached

Method of Reduction
[x] Shutdown of Entire Stationary Source, S-1637 (Split and re-issue of Emissions Reduction Credit Certificate #S-1463-1)
[ ] Shutdown of Emission Unit
[ ] Other:

Pursuant to section 4.2.5.1 of Rule 2201, these reductions may not be used as offsets for emissions from a major source or for a Title I Modification. Due to previous agreements regarding these reductions, this prohibition does not apply to the use of these reductions as offsets for the snack food facility located at 22801 Highway 58 in Bakersfield, California.

David L. Crow, APCO

Seyed Sadredin
Director of Permit Service

San Joaquin Valley
Air Pollution Control District

Southern Regional Office • 2700 M Street, Suite 275 • Bakersfield, CA 93301-2370

Emission Reduction Credit Certificate
S-1700-1

T/O to Duke
Energy North America
S-5243 8/17/04
as cert S-2083-1
filed in S-1637
1043224

ISSUED TO: DUKE ENERGY AVENAL, LLC

ISSUED DATE: December 13, 2001

LOCATION OF REDUCTION: 20807 STOCKDALE HIGHWAY
BAKERSFIELD, CA (MAJOR SS)
SECTION: 14 TOWNSHIP: 32S RANGE: 23E

For VOC Reduction In The Amount Of:

Quarter 1	Quarter 2	Quarter 3	Quarter 4
87,500 lbs	87,500 lbs	87,500 lbs	87,500 lbs

[ ] Conditions Attached

Method Of Reduction

[X] Shutdown of Entire Stationary Source
[ ] Shutdown of Emissions Units
[ ] Other

SHUTDOWN ENTIRE STATIONARY SOURCE

Use of these credits outside the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) is not allowed without express written authorization by the SJVUAPCD.

David L. Crow, Executive Director / APCO

Seyed Sadredin, Director of Permit Services

Exhibit L

DRAFT

ERC APPLICATION REVIEW

DEEMED COMPLETE:	6/22/92	ENGINEER:	Lance Ericksen
DATE START:	4/16/92	TITLE::	Senior AQE
DATE FINISH:	8/21/92		

6026001/101/201/401/501/601

Facility Name: FRITO-LAY, INC.
Mailing Address: 222801 Highway 58
Bakersfield, CA 93312

Project #: 6026 920416
WP File #: 92LE026

Contact Name: H.C. Bradbury
Title: Group Manager, Environmental Policy & Affairs
Phone: (214) 334-4742

I. ~~PROPOSAL~~: Summary

The applicant ~~is~~ requesting ERC Banking Certificates pursuant to Rule 230.1 IV.A.1. - reductions occurring prior to January 1, 1988. The reductions were obtained from shutdown of Continental Carbon a carbon black production facility for use as offsets at the Frito-Lay facility. These reductions were recognized in writing by the District as available for offsets prior to adoption of the Kern County banking rule for use only at the Frito-Lay facility. Any credits available for banking will also be limited for use as offsets at the Frito-Lay Facility. A portion of these reductions was used for approval of the current Frito-Lay facility in addition a portion of the reductions were donated to the KCAPCD in 1989. The reductions dedicated to previous projects and the portion donated to the District is not surplus and the applicant has not requested to bank these amounts.

this the source to
apply for banking
pursuant to ____

Include Results previously recognized reduction
actual except NO_2

II. APPLICABLE RULES:

Rule 230.1 - Emission Reduction Credit Banking (March 11, 1992)

To qualify for banking the emissions reductions must comply with the requirements of subsection IV.A.2. The requirements of this subsection are summarized below:

1. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

2. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable.

3. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

4. The reductions are included in or have been added to the 1987 emissions inventory.

5. The banking application must be filed within 180 days of the date of rule adoption.

III. PROJECT LOCATION:

The carbon black facility was located 8 miles west of Bakersfield on Stockdale Highway Section 14, Township 32S, Range 23E. The Frito-Lay facility is located west of Bakersfield on highway 58 at Section 20, Township 29S, Range 25E. A map showing the relative locations of the facilities are shown on page 3.

IV. ~~PROCESS DESCRIPTION~~: Method of Generating Emission Reductions

The carbon black facility was comprised of two independent carbon black production trains. Unit 1 produced a hard type or tread grade carbon black. Unit 2 produced a soft type or carcass grade carbon black. Both units use the oil furnace process for production of carbon black. Flow diagrams and a description of the process used is shown on page 5.

~~Sequence of events.~~
Purchased credits by obtaining permits
Permits Maintained

Skip – process description
move to calculations

V. EQUIPMENT LISTING:

Credits generated are associated with eight permits to operate for the carbon black facility the equipment associated with each permit is:

6026001	Unit 1 Reactors
6026002	Unit 1 Pulverizer/pelletizers
6026003	Unit 1 Dryer
6026004	Unit 1 Screens/separators/storage/bagging/loadout
6026005	Unit 2 Reactors
6026006	Unit 2 Pulverizer/pelletizers
6026007	Unit 2 Dryer
6026008	Unit 2 Screens/separators/storage/bagging/loadout

Skip

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

No equipment control technology evaluation is required. This project is to bank previously recognized emission reduction credits for black manufacturing facility where operations have ceased.

VII. CALCULATIONS:

A. PM-10, CO and VOC Emissions Reductions

Emission reductions previously recognized by the District of PM-10, CO and VOC are based on AP-42 emission factors and actual carbon black production for the facility. The baseline carbon black production emission factors and calculation of actual emission reductions of TSP, CO and VOC are shown on pages 9-14.

Conversion of TSP to PM-10

The AP-42 emission factor is for TSP. Information submitted by the applicant demonstrates that all the size of carbon black produced at the facility is less than 10 microns. It can therefore be concluded that all emissions of particulate matter from the carbon black production facility are also 10 microns or less and thus the TSP emissions are all PM-10. The basis for this conclusion is show on pages 15-21.

AP-42

TABLE 5.3-3. EMISSION FACTORS

EMISSION FACTOR

Process	Particulate[b]		Carbon Monoxide		Nitrogen Oxides	
	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
Oil furnace process						
Main process vent	3.27[d] (0.1-5)	6.53[d] (0.2-10)	1,400[e] (700-2,200)	2,800[e] (1,400-4,400)	0.28[e] (1-2.8)	0.56[e] (2-5.6)
Flare	1.35 (1.2-1.5)	2.70 (2.4-3)	122 (108-137)	245 (216-274)	NA	NA
CO boiler and incinerator	1.04	2.07	0.88	1.75	4.65	9.3
Combined Dryer vent						
Bag filter[h]	0.12 (0.01-0.40)	0.24 (0.02-0.80)			0.36 (0.12-0.61)	0.73 (0.24-1.22)
Scrubber[h]	0.36 (0.01-0.70)	0.71 (0.02-1.40)			1.10	2.20
Pneumatic system vent[h]						
Bag filter	0.29 (0.06-0.70)	0.58 (0.12-1.40)				
Oil storage tank vent[i]						
Uncontrolled						
Vacuum cleanup system vent[h]						
Bag filter	0.03 (0.01-0.05)	0.06 (0.02-0.10)				
Fugitive emissions[h]	0.10	0.20				
Solid waste incinerator[j]	0.12	0.24	0.01	0.02	0.04	0.08
Thermal process[k]	Neg	Neg	Neg	Neg	Unknown[l]	Unknown[l]

used .45 for uncontrolled vent

[a] Expressed in terms of weight of emissions per unit weight of carbon black produced. Blanks indicate no emissions. Most plants use bag filters on all process trains for product recovery except solid waste incineration. Some plants may use scrubbers on at least one process train. NA = not available.

[b] The particulate matter is carbon black.

[c] Emission factors do not include organic sulfur compounds which are reported separately in Table 5.3-2. Individual organic species comprising the nonmethane VOC emissions are included in Table 5.3-.2

[d] Average values based on surveys of plants (References 4-5).

[e] Average values based on results of 6 sampling runs conducted at a representative plant with a mean production rate of 5.1 x 10 Mg/yr (5.6 x 10 ton/yr). Ranges of values are based on a survey of 15 plants (Reference 4). Controlled by bag filter.

[f] Not detected at detection limit of 1 ppm.

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FOR CARBON BLACK MANUFACTURE[a]

RATING: C

Sulfur Oxides		Methane		Nonmethane VOC[c]		Hydrogen Sulfide	
kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton	kg/Mg	lb/ton
0[e,f] (0-12)	0[e,f] (0-24)	25[e] (10-60)	50[e] (20-120)	50[e] (10-159)	100[e] (20-300)	30[e] 5S-13S[g]	60[e] 10S-26S[g]
25 (21.9-28)	50 (44-56)			1.85 (1.7-2)	3.7 (3.4-4)	1	2
17.5	35.2			0.99	1.98	0.11	0.22
0.26 (0.03-0.54)	0.52 (0.06-1.08)						
0.20	0.40						
				0.72	1.44		
0.01	0.02			0.01	0.02		
Neg	Neg			Neg	Neg	Neg	Neg

[g]S is the weight percent sulfur in the feed.

[h]Average values and corresponding ranges of values are based on a survey of plants (Reference 4) and on the public files of Louisiana Air Control Commission.

[i]Emission factor calculated using empirical correlations for petrochemical losses from storage tanks (vapor pressure = 0.7 kPa). Emissions are mostly aromatic oils.

[j]Based on emission rates obtained from the National Emissions Data System. All plants do not use solid waste incineration. See Section 2.1.

[k]Emissions from the furnaces are negligible. Emissions from the dryer vent, pneumatic system vent and vacuum cleanup system and fugitive sources are similar to those for the oil furnace process.

[l]Data are not available.

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TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S}) (64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /60	0 /4293
Dryer Vent	0.52/0	37.2/0
Boilers	142S (lbs/10^6 gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S) (0.50) (64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

Continental Carbon Company

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

CONTINENTAL CARBON EMISSION CREDITS

I. Carbon Black Production (avg. of yrs. '72 through '79): 52,288,712 lbs/yr (See Attachment 1)

$$\frac{52{,}228{,}712 \text{ lbs/yr}}{2000 \text{ lbs/ton } (365 \text{ days/yr})} = 71.55 \text{ ton/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP42 emission factors for Carbon Black Manufacture (B Oil furnace process), 7/79.

PROCESS	EMISSION FACTORS (lbs/ton of Product)			
	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Main Process Vent	6.53	2,800	100	60
Dryer Vent Uncontrolled (Firebox)	.45	---	---	---
Pneumatic System Vent Bag Filter	.58	---	---	---
Oil Storage Tank Vent	---	---	1.44	---
Vacuum Cleanup System Vent	.06	---	---	---
Fugitive Emissions	.20	---	---	---
SOURCE TOTAL	7.82	2,800	101.44	60
Less 29.5% for Modification in 1978 does not impact TSP.	---	826	29.92	17.70
Emission Factor Total	7.82	1,974	71.52	42.30

ATTACHMENT 1

BAKERSFIELD PLANT PRODUCTION

YEAR	TREAD	CARCASS	TOTAL
1981	8,897,300 lbs.	7,263,200 lbs.	16,160,500 lbs. (8 mos. + 10 days = .6932 yr.)
1980	11,777,100 "	15,452,300 "	27,229,400 "
1979	21,116,800 "	27,492,600 "	48,609,400 "
1978	20,848,100 "	24,922,400 "	45,770,500 "
1977	30,000,300 "	25,828,200 "	55,828,500 "
1976	18,703,000 "	21,786,500 "	40,489,500 "
1975	24,327,900 "	25,190,700 "	49,518,600 "
1974	32,349,100 "	26,538,000 "	58,887,100 "
1973	32,037,800 "	30,009,200 "	62,047,000 "
1972	29,294,000 "	27,865,100 "	57,159,100 "
Averages	22,935,140	23,234,820	46,169,960 lbs. (avg. 9.6932 yrs)
Averages	24,494,900	25,009,444	49,504,344 lbs. (avg. 9 yrs-'72 thru '80)
Averages	26,084,625	26,204,087	52,288,712 lbs. (avg. 8 yrs - '72 thru '79)

December 22, 1982

CALCULATION OF EMISSION REDUCTION CREDITS (REVISED)

I. Line #1 (tread) Carbon Black Production (avg. of yrs. '72 through '79): 26,084,625 lbs.

$$\frac{26{,}084{,}625 \text{ lbs/yr}}{2{,}000 \text{ lbs/Ton } (365 \text{ days/yr})} = 35.73 \text{ Tons/day Carbon Black}$$

II. The following emission estimates utilize USEPA AP-42 emission factors for Carbon Black Manufacture (B Oil Furnace Process), 7/79, and the avg., daily production rate shown above.

LINE #1 EMISSIONS (lbs/day)

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Uncontrolled	279.4	100,044.0	3,624.4	2,143.8
Less 29.5% for 1978 Modification	-----	29,513.0	1,069.2	632.4
Total ERC for Line #1	279.4	70,531.0	2,555.2	1,511.4

III. Line #2 (carcass) Carbon Black Production (avg. of yrs. '72 through '79): 26,204,087 lbs

$$\frac{26{,}204{,}087 \text{ lbs/yr}}{2{,}000 \text{ lbs/Ton } (365 \text{ days/yr})} = 35.90 \text{ Tons/day Carbon Black}$$

IV. The following emission estimates utilize USEPA AP-42 emission factors for Carbon Black Manufacture (B Oil Furnace Process), 7/79, and the avg., daily production rate shown above.

LINE #2 EMISSIONS (lbs/day)

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Uncontrolled	280.74	100,520.0	3,641.7	2,154.0
Less 39% for 1978 Modification	-----	39,202.8	1,420.3	840.1
Total ERC for Line #2	280.74	61,317.2	2,221.4	1,313.9

1054S/CTW/ss

V. Total Emission Credit

A.

	PARTICULATE	CO	HC	HYDROGEN SULFIDE
Line #1	279.4	70,531.0	2,555.2	1,511.4
Line #2	280.74	61,317.2	2,221.4	1,313.9
Total Credit lbs/day	560.1	131,848.2	4,776.6	2,825.3

B. SO_x - Specific Limiting Condition is 198.9 lbs/hr

198.9 lbs/hr (24 hr/day) = 4,773.6 lbs/day

H_2S Conversion to SO_2 (1978 Modification)

Source	H_2S	SO_2
Line #1	632.4	1,188.9
Line #2	840.1	1,579.4
		2,768.3 lbs/day

SO_2 Emission Credit

4,773.6 lbs/day (specific limiting condition)
2,768.3 lbs/day (H_2S conversion - '78 mod.)

7,541.9 lbs/day TOTAL SO_2 EMISSION CREDIT

C. NO_x - Specific Limiting Condition is 44.14 lbs/hr

44.14 lbs/hr (24 hrs/day) = 1,059.36 lbs/day

1054S/CTW/ss

Quantification of PM10 Emissions

Background

Unit 1 reactor at Continental Carbon's Bakersfield facility produced a hard type or tread grade (HAF) carbon black. A soft type or carcass grade (GPF) carbon black was produced in Unit 2 reactor. Emission reductions for particulate were calculated using AP-42 emission factors for Carbon Black manufacture(B oil furnace), 7/79. These emission factors have remained unchanged in the more current 5/83 edition. These emission factors were applied to a carbon black production rate of 71.55 tonnes/day, which was an average of eight years production spread over 365 operating days per year.

Discussion

From our records' search, particle size data for the Continental Carbon facility in Bakersfield is not available. However, technical literature on carbon black processing and the associated emission sources address particle size, specifying mean particle size for the various grades of carbon black produced. This information is provided below for the grades of carbon black produced at the Bakersfield facility.

Grade	Symbol	Mean Particle Size--nm
High Abrasion Furnace-Low Structure	HAF-LS	25 to 26.5
High Abrasion Furnace-High Structure	HAF-HS	22 to 25
General Purpose Furnace	GPF	50 to 55

Source: Serth, R.W. and Hughes, T.W., Source Assessment: Carbon Black Manufacture, October, 1977, pp. 10-13.

Conclusion

As noted in the process description for Carbon Black manufacturing (AP42, 5/83), "...the unburned carbon is collected as an extremely fine black fluffy particle, 10 to 500 nm diameter". Although particle size data was not located in the District's files or in Frito-Lay's records, a literature search revealed that particle size is a function of the grade of carbon black produced. The mean particle size for the grades produced at the Bakersfield facility fall in the range of 22--55 nm. As noted in the Engineering and Cost Study of Air Pollution Control for the Petrochemical Industry, Volume 1: Carbon Black Manufacture by the Furnace Process, "...size distribution of particulates

Exhibit M

LAW OFFICES OF
PILLSBURY, MADISON & SUTRO
225 BUSH STREET
POST OFFICE BOX 7880
SAN FRANCISCO, CALIFORNIA 94120
TELEPHONE (415) 983-1000

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333 WEST SANTA CLARA STREET
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TELEX 34743
TELECOPIER (415) 398-2096

WALNUT CREEK
1646 N. CALIFORNIA BLVD.
WALNUT CREEK, CALIFORNIA 94
TELEPHONE (415) 946-250

WASHINGTON, D.C.
1667 K STREET, N.W.
WASHINGTON, D.C. 20006
TELEPHONE (202) 887-030

WRITER'S DIRECT DIAL NUMBER

(415) 983-1151

Xpace

November 12, 1987

<u>Frito-Lay, Inc. - Air Pollution - Highway 58 Project, Kern County, California</u>

Dr. Leon M. Hebertson
Air Pollution Control Officer
Kern County Air Pollution Control District
1601 "H" Street, Suite 150
Bakersfield, CA 93301-5199

Dear Dr. Hebertson:

To follow up our meetings regarding the Frito-Lay Highway 58 Project in Kern County, we request confirmation of the remaining balance of emission reduction credits available to Frito-Lay at the Project site.

As background, Frito-Lay started planning the Project in 1982, contracted for the necessary emission reduction credits for use as emission offsets in 1982 and, in 1983, began submitting applications to the District for Authorities to Construct elements of the Project. Initial Project elements have now been completed and are operational. At this time, further Project elements are in a preliminary stage and further applications for Authorities to Construct them would be premature. As indicated in the Frito-Lay Business Discussion and Project Descriptions attached, Frito-Lay intended its new Kern County manufacturing complex to be constructed in stages and it will consist of various types of processes normally conducted by it and its affiliates.

In response to the elaborate process of obtaining applicable permits from various regulatory agencies and in response to the developing market for food products manufactured by Frito-Lay and its affiliates on the West Coast, development of the Project has necessarily been a lengthy process which continues through today and will continue for some period of time.

To meet the specific regulatory requirements of the Kern County Air Pollution Control District, Frito-Lay was required to obtain emission reduction credits to utilize as offsets for various increases in air pollutant emissions from elements of the Project. In order to provide sufficient offsets for all of the possible particular elements of the full Project, Frito-Lay contracted with Continental Carbon Corporation (CCC) in good faith in compliance with both Federal regulations and the Kern County NSR Rule. The CCC emissions credits were required both for specific Project elements which had passed through the design and engineering phase at that time and for those Project elements to be located at the Project site in the future. At the present time, only a portion of the originally available CCC emissions credits have been consumed by completed and operational Project elements and, accordingly, Frito-Lay wishes to ask the District to confirm the amounts available for future Project elements at the Project site.

Frito-Lay does not request use of the remaining CCC emissions credits at any site other than the Project site on Highway 58 and does not request permission to sell or trade excess CCC emissions credits.

The attached materials should provide the factual basis upon which the District can confirm the remaining amount of CCC emissions available for use by Frito-Lay in permitting future items of equipment at the Project site pursuant to the Rules and Regulations of the Kern County APCD.

In addition, we ask that you consider the following legal bases in support of the requested District confirmation of remaining CCC emissions credits:

(1) In order to construct and develop the full Project, Frito-Lay was required by Kern County APCD rules (and, in turn, Kern County was required by the Clean Air Act and EPA regulations) to obtain and apply emission reduction credits for use as offsets against the increased emissions from the Project (Clean Air Act § 173; EPA Emission Offset Interpretive Ruling, 40 C.F.R., Part 51; Kern County APCD Rules 210.1.3C, 210.1.5B). Frito-Lay obtained the CCC credits, paid the CCC PTO emission fees, held the CCC PTO's in its name and relied on them to mitigate Project emissions pursuant to Kern County APCD Rule 210.1.5B2. Having provided the offsets required

to mitigate a project emissions, Frito-Lay should not later be subject to loss of these established offsets through discounting or disallowance for use in mitigating the remaining emissions from later Project elements.

(2) The Project is large (see Frito-Lay Project Description attached), has an extended buildout time and must respond to a dynamic, developing marketplace (see Frito-Lay Business Discussion attached). Accordingly, Frito-Lay endeavored to obtain sufficient offsets to last for the duration of the full Project build-out. Frito-Lay is requesting that the CCC emission reduction credits be confirmed for use for the balance of development at the Project site, in accordance with basic Districts practice in cases of lengthy, phased projects.

(3) Had an approved, fully functioning air pollution emission bank been available, Frito-Lay would have been able to use such a bank to assemble the necessary emission reduction credits, use them as necessary and store the balance over time. By analogy to such a functioning banking system, Frito-Lay acquired the full amount of emission reduction credits anticipated to be necessary for the Project site, has applied them to specific ATC's issued to date and wishes to store the rest for the balance of the necessary Project ATC's. Therefore, Frito-Lay's maintenance of the CCC PTO's was essentially equivalent to duly banked emissions and should be available for remaining Project elements.

(4) Both Kern County APCD and EPA carefully examined Frito-Lay's use of CCC emission credits and allowed them to be used for the Project subject to extraordinary, specific use restrictions. Frito-Lay concurred and continues to concur with the decision that any remaining CCC emission reduction credits may be used for "future expansion integral to the SR 58 Project" and recognizes that the remaining emission reduction credits "can only be used at the Highway 58 site," as stated in EPA's letter of April 10, 1984.

Accordingly, Frito-Lay requests that the remaining emission reductions credits represented by Kern County APCD

Permits to Operate Nos. 6026001-008 be preserved formally for use as emission offsets for the future Authorities to Construct issued to Frito-Lay to build out its Project at the 100 acre, Highway 58 site. In particular, we ask that the remaining amounts (lbs/day/pollutant) of available credits be specified in a formal, enforceable permit condition applicable to the Project, pursuant to Kern County APCD Rule 210.1.6.

We trust that this letter and its attachments adequately describe the uses for the remaining emission reduction credits and that the method requested for their preservation for future use is acceptable to the District. We look forward to your favorable response and the final resolution of this matter of vital interest to the future of Frito-Lay in Kern County.

Very truly yours,

Michael R Barr

Michael R. Barr

Encs.

cc: Mr. J. Rich, Plant Manager
Mr. H. C. Bradbury

FRITO-LAY, INC. - KERN COUNTY
AUTHORITY TO CONSTRUCT APPLICATIONS
PERMITS TO OPERATE
15 OCTOBER 1987

TABLE 1

EMISSIONS - LBS/DAY

APCD PERMIT # 3082 DESCRIPTION	PARTICULATES	NOx	SO2	SO4	HC	CO
PERMITS TO OPERATE GRANTED						
001 BOILER #1	14.16	99.93	251.26	4.24	2.81	35.40
003 PC #1	73.64					
005 DTC #1	16.80					
006 DTC #2	16.80					
007 CORN HANDLING	7.44					
008 VOID	-					
009 CANCELLED	-					
010 CANCELLED	-					
011 CANCELLED	-					
012 WWT SYSTEM	-					
SUBTOTAL	128.84	99.93	251.26	4.24	2.81	35.40
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED						
004 FCC #1	30.00					
013 FCC #2	30.00					
014 COGEN	29.76	299.52	1.28	4.09	32.88	345.60
015 STARCH DRYER	16.82					
SUBTOTAL	106.58	299.52	1.28	4.09	32.88	345.60
TOTAL INSTALLED EMISSIONS	235.42	399.45	252.54	8.33	35.69	381.00
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED						
002 BOILER #2	9.59	99.93	1.00	1.00	2.81	61.01
016 PC #2	73.68					
SUBTOTAL	83.27	99.93	1.00	1.00	2.81	61.01
TOTAL PERMITTED EMISSIONS	318.69	499.38	253.54	9.33	38.50	442.01

FRITO-LAY, INC. - KERN COUNTY
EMISSION OFFSETS REQUIRED
15 OCTOBER 1987

TABLE 2

EMISSION OFFSETS
REQUIRED @ 1.2:1
EMISSIONS - LBS/DAY

APCD PERMIT # 3082 DESCRIPTION	PARTICULATE	NOx	SO2	SO4	HC	CO	H2S
PERMITS TO OPERATE							
001 BOILER #1	16.99	119.92	301.51				
003 PC #1	88.37						
005 DTC #1	20.16						
006 DTC #2	20.16						
007 CORN HANDLING	8.93						
008 VOID							
009 CANCELLED							
010 CANCELLED							
011 CANCELLED							
012 WWT SYSTEM							
SUBTOTAL	154.61	119.92	301.51				
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED							
004 FCC #1	36.00						
013 FCC #2	36.00						
014 COGEN	35.71	359.42	1.54				
015 STARCH DRYER	20.18						
SUBTOTAL	127.90	359.42	1.54				
TOTAL INSTALLED OFFSETS REQ'D.	282.50	479.34	303.05				
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED							
002 BOILER #2	11.51	119.92	1.20				
016 PC #2	88.42						
SUBTOTAL	99.92	119.92	1.20				
TOTAL PERMITTED OFFSETS REQ'D.	382.43	599.26	304.25				

FRITO-LAY, INC. - KERN COUNTY
EMISSION REDUCTIONS AVAILABLE
15 OCTOBER 1987

TABLE 3

EMISSION REDUCTIONS
EMISSIONS - LBS/DAY

APCD PERMIT # 6026 DESCRIPTION	PARTICULATES	NOx	SO2	SO4	HC	CO	H2S
PERMITS TO OPERATE							
001 UNIT 1 REACTORS							
002 UNIT 1 PULVERIZER/PELLETIZERS							
003 UNIT 1 DRYER							
004 UNIT 1 SCREENS/SEPARATORS/STORAGE/BAGGING/LOADOUT							
005 UNIT 2 REACTORS							
006 UNIT 2 PULVERIZER/PELLETIZERS							
007 UNIT 2 DRYER							
008 UNIT 2 SCREENS/SEPARATORS/STORAGE/BAGGING/LOADOUT							
TOTAL	560.1	1059.4	4773.6	0	4776.6	131,848.2	753.4

FRITO-LAY, INC. - KERN COUNTY
EMISSION REDUCTIONS
OFFSETS APPLIED @ 1.2:1
15 OCTOBER 1987

TABLE 4

REMAINING EMISSION REDUCTIONS
EMISSIONS - LBS/DAY

APCD PERMIT # 3082 DESCRIPTION	PARTICULATES	NOX	SO2	SO4	HC	CO	H2S
INITIAL EMISSION REDUCTIONS FROM CCC							
TOTAL	560.1	1059.4	4773.6	0	4776.6	131,848.2	753.4
PERMITS TO OPERATE GRANTED							
001 BOILER #1	16.99	119.92	301.51				
003 PC #1	88.37						
005 DTC #1	20.16						
006 DTC #2	20.16						
007 CORN HANDLING	8.93						
008 VOID							
009 CANCELLED							
010 CANCELLED							
011 CANCELLED							
012 WWT SYSTEM							
OFFSET SUBTOTAL	154.61	119.92	301.51	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	405.49	939.48	4472.09	0	4776.6	131,848.2	753.4
AUTHORITIES TO CONSTRUCT - EQUIPMENT INSTALLED							
004 FCC #1	36.00						
013 FCC #2	36.00						
014 COGEN	35.71	359.42	1.54				
015 STARCH DRYER	20.18						
OFFSET SUBTOTAL	127.89	359.42	1.54	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	282.15 277.6	580.06	4470.55	0	4776.6	131,848.2	753.4
AUTHORITIES TO CONSTRUCT - EQUIPMENT NOT INSTALLED							
002 BOILER #2	11.51	119.92	1.20				
016 PC #2	88.42						
OFFSET SUBTOTAL	99.93	119.92	1.20	0.00	0.00	0.00	
REMAINING EMISSION REDUCTIONS	177.67	460.14	4469.35	0	4776.6	131,848.2	753.4

277.60 580.06 4470.55

BUSINESS DISCUSSION
FRITO-LAY KERN COUNTY PROJECT

BACKGROUND

Frito-Lay has been requested to describe the Kern County "project and future expansion plans for the project" with regard to use and preservation of the remaining CCC ERC's. The remaining ERC's are necessary as emission offsets for future expansion and remaining development of the project. The attached description of the "Frito-Lay Kern County Project" is in response to that request. The project is described in terms of the 100 acre, Highway 58 site. The expansion of the project is described as the full development of the 100 acre, highway 58 site within certain specific environmental impacts and specific parameters to residents of Kern County.

Specific initial project processes and operations were the subject of specific past permit applications and numerical computations. They were also cited as examples of the types of activities that may be included in the fully developed project in various correspondence and discussions. However, the entire project has always been referred to as a "major food processing/distribution complex", or similar generic words, in all communications on this matter by all of the parties involved, including Kern County APCD and the EPA.

To define the project within a narrow range of specific operations and processes would be inconsistent with previous correspondence and discussions and inappropriate to the basic nature of the project scope and businesses of Frito-Lay. Even though the full project scope to develop the 100 acre, Highway 58 site has not changed, there have already been major changes in the products to be produced on-site, the method of production and the scheduling of the product production.

MARKET DRIVEN COMPANY

Frito-Lay is basically a marketing driven company that operates in a very competitive and dynamic marketplace nationwide. Its engineering and manufacturing units support the marketing strategies in both long and short term execution. In implementing the plant objectives that were used to describe the project, the Kern project site is intended to produce the type of product, in the necessary quantities and at a competitive price as dictated by marketing. The following are examples of how the original partial, preliminary project scope has changed to accommodate the marketing strategies.

> To provide the desired product mix from a marketing prospective, Phase I construction included a bakery in addition to the traditional salty snack facility. A new fruit snack food process was subsequently added to the project and granted approval by Kern County APCD.

To support sales forecasts in the major West Coast markets a second FRITOS\ brand corn chip line was added to the first phase construction plan in advance of its Phase II planned installation. A permit was also requested and approval granted by Kern County APCD for the second potato chip line before the plant even began operation in response to refined, projected market demand.

To achieve operating economies to meet sales cost objectives, a Cogeneration system was included in the initial construction phase and the starch dryer installed much earlier than anticipated. Both applications were granted approval by Kern County APCD.

GROWTH ORIENTED

Frito-Lay operates in one of the fastest growing grocery product areas, the salty snack food market. Salty snack food consumption has increased some 25 percent between 1980 and 1986. Frito-Lay, with 18 consecutive years of increased sales, has experienced a growth rate nearly one and one-half times the average of all grocery store products. Much of that growth has come from new products. From only two major brands in 1965, Frito-Lay now markets seven major product brands and is the market leader. The marketing, innovation and productivity that made this exceptional growth possible will be no less evident in the future. The Kern County project is situated with the potential to be in the forefront of the continued growth of Frito-Lay and the expanding snack food market.

WEST COAST LOCATION

Of the several Frito-Lay plants west of the Rocky Mountains, the Kern County facility is the only plant that is both centrally located and has "insurance" land and building space suitable for the new products and technologies projected in the marketing forecast. Any national new product roll-out would depend upon Kern to support expansion to the West Coast. Kern is also the logical location in which to continue development of the nontraditional (other than potato and corn chip) snack food lines because of access to the local agricultural products as identified in the plant objectives.

These new snack food processes, as well as existing product lines such as corn meal products, nuts, dips and meat snacks which were not included in the initial preliminary, phases of the project, are similar to the corn and potato chip processes already installed at the site. The emissions, air pollution control and environmental impact would also be similar to those for the existing salty snack sources.

PRODUCTION CAPACITY INCREASE OBJECTIVES

In addition to selective development of new product lines, growth in the existing core brands and reaching new market segments, one of the major strategies for growth at Frito-Lay, consistent with the Kern County project expansion originally envisioned by the planning documents, permit applications and EIR, is to "reduce costs through increased productivity, utilizing new technologies and manufacturing efficiencies." Basic corporate strategy now emphasizes the full, economical utilization of existing facilities, especially "high tech" plants such as Kern. This strategy implies the constant upgrading of processes in both efficiency and capacity, and in many cases potential increases in atmospheric emissions. Such actions require permit modifications for which emission offsets may be required. Anticipating this potential offset requirement, Frito-Lay acquired offsets from CCC for the Kern site sufficient to allow full project build-out.

PEPSICO, INC., SUBSIDIARY

Frito-Lay is only one of the major operating divisions of PepsiCo, Inc. Others include Taco Bell, Inc., Pizza Hut, Inc. and Kentucky Fried Chicken, Inc. It is economically imperative that Frito-Lay's food processing plants be sufficiently flexible to accommodate the food operations of any other PepsiCo division that would benefit from the centralized west coast location of kern County and its agricultural resources. Process operations of Frito-Lay and other PepsiCo operating divisions would fully meet the criteria described for future development at the 100 acre, highway 58 site in the EIR. Use of the CCC Emission Reduction Credits for such operations, would of course, remain the exclusive right of the Frito-Lay-PepsiCo family.

SUMMARY

The full project scope has naturally evolved in definition and timing, with specific process operations added, deleted and modified since the initial permit applications were made. There is no reason to anticipate that this on-going, dynamic planning will become static in the future since change and growth are basic to the Frito-Lay/Pepsico business segments. The original plan considered in the EIR contemplated limited expansion, the precise details of which were necessarily less well defined. The scope of the potential of Frito-Lay's expansion is not diminished and the potential benefit to both Frito-Lay and Kern County should not be limited. Frito-Lay needs the flexibility to meet the requirements of a fluctuating and competitive market-place within the framework of the stated intent of the EIR. The use of the CCC Emission Reductions gives Frito-Lay that flexibility in the very important air quality regulatory arena.

FRITO-LAY KERN COUNTY PROJECT

The Kern County facility is the most sophisticated, 'high tech' plant yet built by the PepsiCo subsidiary, Frito-Lay, Inc., anywhere in the world. Its initial cost was $55 million and the start-up operations employ over 525 Kern County residents. The facility is the first phase of a large food processing complex that is intended to be developed as the major production/distribution operation for the Pepsico family on the West Coast. The Kern County site was selected because of its strategic, central location, desirable site characteristics, and attractive potential for future expansion and full build-out.

The existing Frito-Lay salty snack plant occupies only 20-30 acres of a 100 acre core project site that is planned to be fully developed as identified in the planning documents and approvals for the project. The infrastructure (i.e., potable water system process and sanitary wastewater treatment and cogeneration system) to support the planned expansion is already in place.

PROJECT DESCRIPTION

The project is located in Kern County, California on approximately 634 acres located along Highway 58 west of Bakersfield. It consists of the 100 acre core portion of the site for which the Agricultural Preserve was cancelled and that was re-zoned M-2, P-D (Light Manufacturing - Precise Development) for a "food processing complex". An additional 200 acres was designated for land application of wastewater in the agricultural production of grasses and the remaining 300 plus acres of the site were left in the agricultural preserve.

Three of the objectives for locating the project in Kern County are the following:

* To utilize local agricultural products.
* To draw from the local labor force.
* "To better access the Southern California and Nevada market areas for finished production [sic] distribution."

The first phase of the project is the Frito-Lay salty snack manufacturing facility that has been constructed on 20-30 acres of the site and is now in operation. As part of this first phase, the infrastructure of water supply, electric power generation, wastewater treatment, drainage and roadways has been installed to support the future development of the full 100 acre site. Examples of the ultimate build-out and the environmental impacts of the completed project are presented in the various planning documents and permit applications.

FUTURE EXPANSION

The 100 acre, Highway 58 site and build-out of the project are defined most specifically in three documents. They are the Williamson Agricultural Preserve Land Use Contract Cancellation Application, General Plan Amendment Application and Environmental Impact Report.

The Final Environmental Impact Report (EIR) dated July 1, 1983 summarizes the entire project as one in which, "Development of the site will transform approximately 100 acres of undeveloped agricultural land into a food processing facility."

In the General Plan Amendment Application and associated request for a zoning change and submission of a Precise Development Plan, Frito-Lay described the phased development of the project as follows:

> "The ultimate configuration of the snack food and bakery facilities, regional warehouse and ancillary facilities (parking, etc.) will require a total area of 100 acres."

In justifying the cancellation of the Agricultural Preserve Land Use Contract as being in the public interest, one of only two reasons for which it can be cancelled, Frito-Lay described the site and project as:

> "...the location of a snack food production/bakery complex and a warehouse/distribution facility ... The ultimate configuration of this complex, including ..., etc., will require the full 100 acre portion of the parcel. No further development beyond that which is proposed within the 100 acre envelope is planned."

> "The production complex will ... provide over 1000 jobs (at full capacity) to Kern county residents."

ENVIRONMENTAL IMPACT OF PROJECT/FULL PROJECT CONSTRAINTS

A description of future expansion and full build-out of the phased project was presented in the EIR. The food processing/distribution complex was assumed to generate certain levels of traffic, employment, demands on public services and other environmental impacts. It was also analyzed to create certain benefits to the residents and economy of Kern County. Within the originally anticipated scope of these clearly identified constraints, the full project will be developed to the full extent of the 100 acre site potential.

The analysis in the EIR depicts a food production/distribution complex far larger than the present salty snack building, which occupies only 20-30 acres of the 100 acre site, that is now in place or proposed by currently approved APCD Authorities To Construct. The EIR describes the 100 acre, Highway 58 site project as having the following physical dimensions, environmental impacts and development constraints at ultimate build-out:

A complex of 750,000 square feet under roof on 100 acres of improved land eventually costing from $85-100 million.

Parking provided for 1194 cars and 150 tractor trailer trucks.

An approximate employment of over 1500 working around the clock, 5 days/week with weekends devoted to general sanitation activities necessary in a food processing operation.

Use of 1150 acre-feet/year of well water, with 53,000 gallons/day of sanitary sewage treated on-site and one million gallons/day of industrial wastewater treated by on-site land application in a 200 acre field producing alfalfa or other grasses

Use of 2.5 million KWHR/month of electricity and 72 million cubic feet/month of natural gas for the processes, three 60,000 PPH high pressure steam boilers and several smaller boilers. Cogeneration was a consideration to supply the electrical demand on-site.

Solid waste generation of 100 tons/day with over 25 tons/day going to local landfills and the remainder being reclaimed as by-product.

Consumption of 66,000 gallons/month of gasoline and 115,000 gallons/month of diesel fuel by employee and product distribution traffic in 2636 vehicle and 446 truck trips/day.

A four-fold increase in trains on the Buttonwillow branch of the Southern Pacific Railroad to two trains/day.

An increase in traffic noise on Highway 58 west of the site by 6.1 dBA and a train noise increases of 3 dBA.

Environmental quality defined in terms of fence-line air quality, odor detectability and community noise levels.

SUMMARY

The Frito-Lay Kern County project is the 100 acre, Highway 58 site that was re-zoned M-2, P-D and had a General Plan Amendment approved for the phased development of a major food processing/distribution complex. The full project will be expanded to the full potential of the 100 acre, Highway 58 site within the envelope of certain boundaries and constraints identified by the EIR. No further development beyond the 100 acre, Highway 58 site is planned as part of this project.

in the process vent is similar to that of the carbon black product being produced. This is because most if not all of the carbon black emitted is a result of small leaks in the product recovery bag filters". From this it can be concluded that particles emitted from the Continental Carbon facility in Bakersfield would fall in the range of 22--55 nm(mean particle size), the same particle size as the carbon black produced at the facility. Thus, all of the remaining particulate emission reductions represent actual PM10 emissions.

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service
PB-273 068

Source Assessment Carbon Black Manufacture

Monsanto Research Corp., Dayton, Ohio

Prepared for

Industrial Environmental Research Lab., Research Triangle Park, N.C.

Oct 77

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SECTION III

SOURCE DESCRIPTION

A. PRODUCT DESCRIPTION

Carbon blacks are essentially elemental carbon in the form of nearly spherical particles of colloidal dimensions. All carbon blacks possess similar properties, and the distinction between the various grades is one of degree rather than kind. In determining the utility of carbon blacks for commercial applications, the most important properties are: (1) particle size; (2) surface area; (3) extent of particle-to-particle association (structure); and (4) surface condition. The basic physical and chemical properties of carbon blacks are described below.

1. Physical Properties

a. Particle Size - The most important physical property of carbon black from the standpoint of commercial applications is particle size. The average particle size of unagglomerated oil furnace blacks ranges from 18 nm to 55 nm, as can be seen in Table 2.[2] For comparison, the properties of carbon blacks produced by the gas furnace, thermal, and

[2]Smith, W. R., and D. C. Bean. Carbon Black. In: Kirk-Othmer Encyclopedia of Chemical Technology, Second Edition, Vol. 4. John Wiley & Sons, Inc., New York, New York, 1964. pp. 243-282.

Table 2. TYPICAL PROPERTIES OF CARBON BLACKS[2]

Grade	Symbol[a]	Mean particle diameter, nm	Surface area N_2 adsorption, m^2/g	Oil absorption, cm^3/g	Nigrometer reading (unitless)	Volatile matter, %	pH	Benzene extract, %
Oil furnace blacks								
Super abrasion furnace	SAF	18 to 21	90 to 125	1.5	86	1.0	8 to 9	0.05
Intermediate super abrasion furnace	ISAF	22 to 25	115	1.3	88	1.0	8 to 9	0.05
Intermediate super abrasion furnace - low structure	ISAF-LS	20 to 23	110 to 130	0.8 to 0.9	87	1.5	8 to 9	0.05 to 0.10
Intermediate super abrasion furnace - high structure	ISAF-HS	22.5	110 to 120	1.4 to 1.6	[illegible]	1.5	8 to 9	0.05
High abrasion furnace	HAF	26 to 30	74 to 100	1.15	90	1.5	8 to 9	0.05
High abrasion furnace - low structure	HAF-LS	25 to 26.5	85 to 110	0.7 to 0.8	87	1.5	8 to 9	0.05
High abrasion furnace - high structure	HAF-HS	22 to 25	80	1.4 to 1.6	90	1.5	8 to 9	0.05
Fast extruding furnace	FEF	40 to 45	40 to 45	1.3 to 1.4	95	1.0	9	0.05
General purpose furnace	GPF	50 to 55	25 to 30	0.9	97	1.0	9	0.05
Conductive furnace	CF	21 to 29	125 to 200	1.3	86 to 93	1.5 to 2	8 to 9	0.06
Gas furnace blacks[b]								
Fine furnace	FF	40 to 50	40 to 50	0.9 to 1.1	90	1.0	[illegible] to 9	0.05
High modulus furnace	HMF	60	30 to 40	0.85	95	1.0	8 to 9	0.10
Semireinforcing furnace	SRF	60 to 80	25 to 30	0.7 to 0.8	97	1.0	8 to 9	0.15
Thermal blacks								
Fine thermal	FT	180	13	0.3 to 0.5	107	0.5	9	1.75
Medium thermal	MT	470	7	0.3 to 0.5	110	0.5	8	0.3
Channel blacks[c]								
High color channel	HCC	9 to 14	400 to 1,000	2 to 4	58 to 69	5 to 16	3 to 4	None
Medium color channel	MCC	15 to 17	[illegible] to 550	1.5	70 to 78	5 to 10	4 to 5	None
Regular color channel	RCC	22 to 29	100 to 140	1.1	80 to 85	5	5	None
Easy processing channel	EPC	29 to 30	100	1.0	85	5	5	None
Medium processing channel	MPC	25 to 28	110 to 120	1.0	83	5	5	None
Medium flow channel	MFC	23 to 25	200 to 210	1.1	80 to 83	7 to 8	4	None
Long flow channel	LFC	22 to 28	300 to 360	1.2	80 to 84	12	3.5	None

[a] ASTM numbers corresponding to the industry classification symbols are shown in Appendix D.

[b] Gas furnace blacks are no longer available. Similar blacks are now made by the oil furnace process (personal communication, H. J. Collyer, Cabot Corporation, Billerica, Massachusetts, 11 May 1977).

[c] Channel blacks are no longer produced domestically; however, they are still available on the international market (personal communication, H. J. Collyer, Cabot Corporation, Billerica, Massachusetts, 11 May 1977).

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channel processes are also included in the table.[a] The nomenclature used in this table is that of the industry descriptive system, which is based on the manufacturing process and performance characteristics of the black. For example, semireinforcing furnace black (SRF) denotes a black with intermediate reinforcing properties in rubber that is produced by the furnace process. The American Society for Testing and Materials (ASTM) has also established a comprehensive nomenclature system for carbon blacks which is given in Appendix D.

Particle size is usually measured with an electron microscope, and the arithmetic mean diameter is reported. The particle sizes tend to be log-normally distributed, and the geometric standard deviation increases with mean particle size.[3,4] Typical particle size distributions are shown in Figure 2.

Particle size is of primary importance in determining the reinforcement properties of carbon blacks in rubber compounds. Small particle size blacks impart high tensile strength and abrasion resistance to rubber, but they are difficult to mix and process. The fully reinforcing blacks (SAF, ISAF, HAF), which provide maximum abrasion resistance (for example, in tire tread), range in particle size from about 18 nm to 30 nm.

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[a] Gas furnace blacks and, to a large extent, channel blacks have been replaced by similar blacks made by the oil furnace process. However, channel blacks are still used in some applications. For example, federal regulations specify the use of channel blacks in certain food processing operations.

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[3] Davidson, H. W., P. K. C. Wiggs, A. N. Churchouse, F. A. P. Maggs, and R. S. Bradley. Manufactured Carbon. Pergamon Press, New York, New York, 1968. pp. 1-55.

[4] Matsubayashi, E. Carbon Black. Sekiyu Gakkai Shi, 16(5):381-386, 1973.

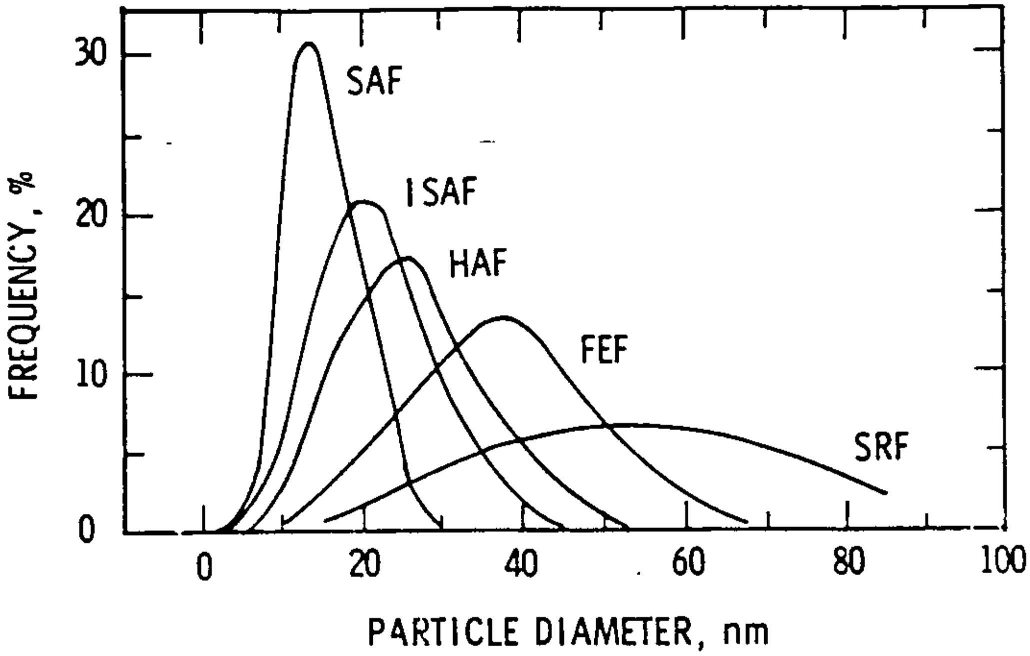

Figure 2. Carbon black particle size distributions for various industry classifications[4]

b. Surface Area - The external surface area of carbon black particles can be calculated from the particle diameter. The total area (internal plus external) is usually measured by gas-adsorption techniques, such as that of Brunauer, Emmett, and Teller (BET). The difference in these two values provides a measure of the internal (porous) surface area.

Low total surface area is desirable in rubber grade blacks since it results in low viscosity and low heat buildup during rubber processing. The high-color and long-flow ink blacks, on the other hand, are highly porous, having total surface areas two to three times greater than their external areas.

Typical specific total surface areas measured by nitrogen adsorption are given in Table 2 for the various grades of black. Some of the newer "improved" carbon blacks have

VII. CALCULATIONS CONT.:

B. SO2 Emissions Reductions

The quantity of SO_2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. This calculation is shown on page 14. The previously recognized amount was compared to actual emissions over the baseline method using AP-42 emission factors and by a method reported by I. Drogin in the Journal of the Air Pollution Control Association. These calculations of actual emissions indicate actual emissions are equivalent to the specific limiting condition (and may have exceeded the permit limitation). Therefore the previously recognized SO_2 emissions may be considered actual emissions reductions. Basis and calculation of actual SO_2 emissions is shown on pages 23-25.

For comparison purposes, Table III presents projected SO_2 emissions from the plant's process sources using two estimating methods. First, as concluded by I. Drogin and reported in his article published in the Journal of the Air Pollution Control Association, "...about 10% of the sulfur in the feedstock ends up in the black(finished product), with 90% going to the effluent." Under this scenario, emissions of sulfur compounds would approximate 3100 lbs/day (as S), based on an average production rate of 71.55 TPD, an average feedstock sulfur content of 1.36% and 394 gal. feedstock/ton of carbon black produced. Based on this method, SO_2 emissions could have been as high as 6200 lbs/day, not including the SO_2 contribution from the boilers which were fired on fuel oil (avg. 1.0%S) from 1977 on.

The other method used in projecting actual SO_2 emissions is AP-42 emission factors applied to the average production rate of 71.55 TPD. The results of this analysis are also shown in Table III. Briefly, the main process vent (reactor exhaust), when not controlled or equipped with a CO boiler or flare, emits significant quantities (>4000 lbs/day) of H_2S. The reactors at ConCarb, Bakersfield were not equipped with a CO boiler or flare. Portions of the reactor offgas were used as combustion fuel for the preheaters and dryers, resulting in the oxidation of this H_2S-rich stream. Actual H_2S/SO_2 emissions were therefore a function of the quantity of reactor offgas used as preheat and drying.

TABLE III
SO_2/H_2S EMISSION PROJECTIONS

Per I. Drogin, emitted Sulfur compounds = 90% of Sulfur in feedstock. Therefore,

(71.55 TPD carbon black) (394 gal feedstock/T produced) (8.98 lbs/gal) (0.0136S) (0.90) = 3098.6 lbs/day as S

If completely oxidized, then

$$\frac{(3098.6 \text{ lbs/day S}) (64 \text{ lbs/lbs mole } SO_2)}{32 \text{ lbs/lbs mole S}} = 6200 \text{ lbs/day } SO_2$$

▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲ ▲

AP-42 Emission Factors

Source	AP-42 lbs/Ton SO_2/H_2S	SO_2/H_2S lbs/day
Main Process Vent	0 /60	0 /4293
Dryer Vent	0.52/0	37.2/0
Boilers	142S (lbs/10^6 gal)	240 /0

If 50% of reactor exhaust (main process vent) is used as combustion air/fuel for preheaters and dryer drums, resulting in the oxidation of 50% of above H_2S emissions shwon in the main process vent exhaust, then

$$\frac{(4293 \text{ lbs/day } H_2S) (0.50) (64 \text{ lbs/lb mole } SO_2)}{(34 \text{ lbs/lb mole } H_2S)} = 4040.47 \text{ lbs/day } SO_2$$

Continental Carbon Company

continex

ATTACHMENT B

March 22, 1983

Mr. H. C. Bradbury
Frito-Lay, Inc.
P. O. Box 47250
Dallas, TX 75247

Dear Mr. Bradbury:

Listed are the average sulfur content of feedstock oils used at the Bakersfield plant per your letter of 3-11-83.

The Bakersfield plant started using liquid fuels in reactors during September, 1977. Before this time, natural gas was the reactor fuel.

YEAR	FEEDSTOCK OIL % sulfur by weight	FUEL OIL % sulfur by weight
1972	1.40%	-
1973	1.53%	-
1974	1.64%	-
1975	1.55%	-
1976	1.38%	-
1977	1.08%	0.79%
1978	Unit 1 1.22%, Unit 2 1.16% (avg 1.19)	same as feedstock (1.19)
1979	1.12%	1.12%
1980	0.80%	0.76%
1981	0.77%	0.79%

The pounds of hydrogen sulfide emissions from Bakersfield plant stacks during the years 1972-1976 are estimated to be as follows:

YEAR	H_2S EMISSIONS FROM UNIT 1	H_2S EMISSIONS FROM UNIT 2	TOTAL H_2S EMISSIONS
1972	234,243 lbs.	285,961 lbs.	520,204 lbs.
1973	279,972 "	336,560 "	616,532 "
1974	303,016 "	319,028 "	622,044 "
1975	215,375 "	286,213 "	501,588 "
1976	147,418 "	220,387 "	367,805 "

VII. CALCULATIONS CONT.:

C. NO2 Emissions Reductions

The quantity of NO2 emissions reductions previously recognized by the District is based on the specific limiting condition for the facility. This calculation is shown on page 14. The specific limiting conditions for the permit are the maximum legal emission from an operation and therefore do not quantify real and actual emissions over the baseline period. To quantify actual emissions of NO2 source test data for the stationary source from November 1978 was used with the actual carbon black production over the baseline period. The source test data is summarized on page 27. Actual emissions over the baseline period are:

Basis

Source test unit 1 NO2 emissions 28.96 lbs/hr
Source test unit 1 production rate 6381.7 lbs/hr or 76.56 tons/day
Average unit 1 production rate 35.73 tons/day (see page 13)

Source test unit 2 NO2 emissions 13.53 lbs/hr
Source test unit 2 production rate 4887.6 lbs/hr or 58.56 tons/day
Average unit 2 production rate 35.90 tons/day (see page 13)

Unit 1 Actual NO2 Emissions:

$$\frac{28.96\text{ lb}}{\text{hr}} \;\Big|\; \frac{24\text{hr}}{\text{day}} \;\Big|\; \frac{35.73\text{ tons/day average}}{76.56\text{ tons/day test}} \quad \square \quad \underline{324.37\text{ lbs/day}}$$

Unit 2 Actual NO2 Emissions:

$$\frac{13.53\text{ lb}}{\text{hr}} \;\Big|\; \frac{24\text{hr}}{\text{day}} \;\Big|\; \frac{35.90\text{ tons/day average}}{58.56\text{ tons/day test}} = \underline{199.07\text{ lbs/day}}$$

Total NO2 Actual Emissions 324.37 + 199.07 = 523.44 lbs/day

NOx Specific Limiting Condition

Background
As required by the Kern Co. APCD, the specific limiting condition for NOx was used as the basis for establishing the quantity of NOx available for emission reduction credits.

Discussion
The specific limiting condition for NOx was based on stack test data, collected by Rockwell International in November, 1978. The supporting stack test data, together with emission rates identified in an October, 1979 Permit Analysis completed by Aerovironment, Inc. for Continental Carbon, are provided below.

Unit No.	Stack No.	Description	NOx Emission Rates lbs/hr Stack Test		Permit
1	1	Main Bagfilter	5.97		5.84
1	2	Main Bagfilter	6.10		5.96
1	3	Oil Preheater	1.30		1.36
1	4	Firebox Stack	13.80		13.75
1	5	Exhaust Bagfilter	1.79	Total	1.79
2	6	Main Bagfilter	.317	Unit 1	.31
2	7	Main Bagfilter	.28	28.96	.27
2	8	Oil Preheater	.713	lb./hr	.74
2	9	Firebox Stack	9.69		10.21
2	10	Exhaust Bagfilter	2.53	Total	2.61
-	11	Boiler #1		Unit 2	.65
-	12	Boiler #2	--	13.53	.65
				lb/hr	
		Total	42.49		44.14

Comparison of the two columns reveals little difference between tested levels and permitted levels. **It should be noted that since the boilers were not stack tested, there is no NOx contribution shown from these sources in the first column.**

VIII. COMPLIANCE:

A. Emissions reductions must have been recognized by the District pursuant to a banking rule or for counties that did not have a banking rule that were formally recognized in writing by the District as available for offsets.

The emission reductions were recognized in writing by the District in February 25, 1983. A copy of this correspondence is shown on pages 32-33 Kern County Air Pollution Control District Rule 210.3 - Emission Reductions Banking was adopted April 25, 1983 therefore, at the time the reductions were recognized the District did not have a banking rule. The reductions therefore satisfy the requirement that they were recognized in writing in a county that did not have a banking rule.

B. The Control Officer determines that such emissions reductions comply with the definition of Actual Emissions Reductions, and such reductions are real, surplus, permanent, quantifiable, and enforceable;

Actual Emissions Reductions

The Rule 230.1 definition of Actual Emissions Reductions states they are as defined in the District's New Source Review Rule. If the reductions are authorized by an Authority to Construct the adjustments made to the actual emissions reductions be as defined in the New and Modified Source Rule, shall be based on the rules, plans, workshop notices at the time the application for such Authority to Construct was deemed complete.

The Rule 220.1 definition of Actual Emissions Reductions states in part they are reductions of actual emissions from an emissions unit selected for emission offsets or banking, from the baseline period. Actual emission reductions shall be calculated pursuant to section V of this rule

The Rule 220.1 definition of Actual Emissions states they are measured or estimated emissions which most accurately represent the emissions from an emissions unit.

Rule 220.1 section V. - Calculations - states the following procedures shall be performed separately for each pollutant, and for each emissions unit or for a concurrent stationary source modification. All calculations shall be performed on a quarterly basis, unless specified otherwise.

For the shutdown of an emissions unit section V.E.2. of Rule 220.1 requires the actual emission reduction to be the Historic Actual Emissions prior to shutdown. Section V. also defines historic actual emissions as emissions having actually occurred based on source tests or calculated using actual fuel consumption or process weight, recognized emissions factors or other data approved by the Control Officer which most accurately represent the emissions during the baseline period.

VIII. COMPLIANCE:

The emissions calculations shown in the preceding section are based on actual process weight, and for PM10, VOC and CO on recognized emissions factors (AP-42) for carbon black plants. The SO2 emissions are validated on feedstock sulfur content and a mass balance. The NO2 emissions are based on actual process weight and source test information. The emissions therefore qualify as Historic Actual Emissions.

The baseline period used in the calculations is the eight year period 1972-1979. This baseline period was used for the calculations because the NSR rule in effect at the time the reductions were authorized by Authority to Construct the NSR rule allowed an alternate baseline "Where the operation of a specific source has been significantly reduced during the previous three years the Control Officer may specify an averaging period emission rate which he determines provides an equitable emission base." (see page 29A). Because this baseline period was allow at the time the reductions were authorized by the issuance of Authorities to Construct for the Frito-Lay snack food facility no adjustment to baseline period is required. These reductions were calculated on an annual daily basis. Because this type of source is not subject to seasonal variation emissions can be expected to ~~run rateably~~ be evenly distributed over the year. ~~and because~~ In addition the ~~an~~ 8 year baseline was used thus annual average the daily reductions may be converted to a quarterly basis by multiplying the daily reduction by the number of days in each quarter. Therefore, the following emissions reductions are actual emissions reductions calculated in conformance with Rule 220.1 and 230.1:

* discuss not precluded by current rule

	Daily Emissions	Reference Page
PM10	560.1	8
SO2	2,768.3	22
NO2	523.4	26
VOC	4,776.6	8
CO	131,848.2	8

Quarterly Emissions

	First	Second	Third	Fourth
Days/Qtr	90	91	92	92
PM10	50,409	50,969	51,529	51,529
SO2	249,147	251,915	254,684	254,684
NO2	47,106	47,629	48,153	48,153
VOC	429,894	434,671	439,447	439,447
CO	11,866,338	11,998,186	12,130,034	12,130,034

As these reductions were recognized prior to 8/22/89 no adjustment for the community bank is required.

B. For an existing source, the emissions of any air contaminant (or precursors, as defined in Section 3.C.2.) for which the area is designated nonattainment under Section 107 of the Clean Air Act, and any air contaminant emissions which are to be used as interpollutant tradeoffs (in accordance with Section 5.B.11) for air contaminants so designated shall be based on the actual operating conditions of the existing source averaged over the three consecutive years immediately preceeding the date of application, or such shorter period as may be applicable in cases where the existing source has not been in operation for three consecutive years, or is seasonal. However, emissions of such air contaminants from a fuel combustion source shall be based on the specific limiting conditions set forth in the existing source's Authority to Construct and Permit to Operate if (1) in the three consecutive years immediately preceding the date of application (or such shorter period as may be applicable) the source had been burning exclusively the dirtiest fuel allowed by the specific limiting conditions, and (2) the specific limiting conditions are representative of normal source operation in terms of operating hours, production rates, and the dirtiest fuel allowed. Where a source has not yet begun normal operation, emissions shall be based on the specific limiting conditions in the Authority to Construct. The emissions of any air contaminant other than those for which the area is designated nonattainment under Section 107 of the Clean Air Act shall be based on the specific limiting conditions set forth in the existing source's Authority to Construct permits and Permits to Operate, and where no such conditions are specified, or where no Authority to Construct was required, on the actual operating conditions as set forth above. Where the operation of a specific source has been significantly reduced during the previous three years, the Control Officer may specify an averaging period or emission rate which he determines provides an equitable emission base. If violations of laws, rules, regulations, permit conditions, or orders of the District, the Air Resources Board, or the Federal Environmental Protection Agency occurred during the period used to determine the operating conditions, then adjustments to the operating conditions shall be made to determine the emissions the existing source would have caused without such violations.

C. The cumulative net change in emissions from new or modified stationary sources which are not seasonal sources shall be determined using yearly emission profiles, or alternate method as specified by the Control Officer subject to consultation with the Executive Officer of the Air Resources Board.

Yearly emissions profiles for an existing or proposed stationary source or modification shall be established by plotting the daily emissions thereafter in descending order. A separate profile shall be constructed for each pollutant.

8/27/84

VIII. COMPLIANCE:

Real

The emissions have, in fact, actually occurred. Production records of carbon black produced by the facility source test data demonstrate that the emissions actually occurred during the baseline period. A summary of these records is shown on page 12. The reductions therefore represent real emissions.

Surplus

The reductions are not required by the SIP or any rule, regulation or law. A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts are not surplus and cannot be banked. A table summarizing the initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting surplus emissions reductions is shown on page 34. The remaining balance of emission reductions are surplus.

Permanent

All equipment associated with the carbon black plant has ceased to operate. Frito-Lay currently holds permits on some of the equipment to insure the credits are retained. Frito-Lay has agreed to surrender these permits prior to issuance of a banking certificate. Therefore the reductions are permanent.

Quantifiable

Actual production records recognized emission factors and source test data have been used to quantify the emission reductions. The calculation of emission reductions is shown in subsection VII. of this evaluation. The reductions therefore are quantifiable.

Enforceable

The permits to operate for the carbon black facility will be surrendered any new construction or operation of existing equipment at the site will require Authority to Construct pursuant to Rule 2010 and will be subject to new source review prior to construction or operation. The reductions are therefore enforceable.

VIII. COMPLIANCE:

C. The reductions have not been used for the approval of an Authority to Construct or used as offsets.

A portion of the reductions was dedicated to previous projects and a portion was donated to the District. These amounts cannot be banked. The initial emission reductions, the amount used for the approval of emissions increases, the amount donated to the District and the resulting remaining (surplus) emissions reductions are shown on page 34.

D. The reductions are included in or have been added to the 1987 emissions inventory.

Upon original approval of these emissions reductions the District required that these emissions be included in the current NAP inventory. To insure the proper amount of emissions is included District planning staff will be informed whenever all or a portion of these emissions are used as offsets for the Frito-Lay facility.

E. The banking application must be filed within 180 days of the date of rule adoption.

The application for emission reduction banking credits was submitted to the District March 17, 1992. This is within 180 days of the date of rule adoption.

F. Because these emission reductions can be validated as Actual Emission Reductions they qualify for ERC banking certificates that may be used in accordance with the requirements of Rule 220.1.

KERN COUNTY AIR POLLUTION CONTROL DISTRICT

1601 "H" Street, Suite 250
Bakersfield, California-93301
Telephone (805) 861-3682

LEON M HEBERTSON, M.D.
Director of Public Health
Air Pollution Control Officer

February 25, 1983

Mr. H. C. Bradbury
Group Manager-Environmental Compliance
Frito-Lay, Inc.
P. O. Box 47250
Dallas, Texas 75247

Dear Mr. Bradbury:

Thank you for your recent letter in which you discuss the Continental Carbon Bakersfield facility's air contaminant emissions. The District has reviewed this facility's specific limiting conditions (contained in Permits to Operate), fuel oil and feedstock average sulfur content (0.8%), and applicable E.P.A. AP-42 emission factors. The following allowable emissions credits were determined from these data. Please note that the hydrocarbon emissions reflect a 50% reduction due to the exclusion of methane. (KCAPCD Rule 210.1 does not allow the use of methane as an emissions tradeoff because it is considered non-photochemically reactive.) The numbers below represent total facility emissions and are in units of lbm/day. Line #1 production rate was considered to be 35.73 tons/day and that of line #2 to be 35.90 tons/day.

Particulates	Carbon Monoxide	Hydrocarbons
560.1	131,848.2	2,388.3
Hydrogen Sulfide	Oxides of Nitrogen	Sulfur Dioxide
753.4	1,059.[illegible]	5,512.3

Even though some of these values are somewhat lower than summarized in your letter, it appears (on the basis of expected emissions summarized in your rough draft A to C application package) that these emissions credits would provide adequate offsets (at a ratio of 1.2:1) for the Frito-Lay plant proposed for Kern County.

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Mr. H. C. Bradbury
Frito-Lay, Inc.
February 25, 1983

Thank you for your cooperation. Should you have any questions, please telephone the Air Quality Control Division at (805) 861-3682.

Sincerely,

LEON M HEBERTSON, M.D.
AIR POLLUTION CONTROL OFFICER

Thomas Paxson, P.E., Manager
Engineering Evaluation Section

TP/dl

FRITO-LAY EMISSION REDUCTION CREDITS

REFERENCE DOCUMENT	TSP = PM10 lbs/day	SO_2 lbs/day	H_2S lbs/day	NO_2 lbs/day	HC = VOC lbs/day	CO lbs/day
9/13/82 Letter to KCAPCD re: basis for ERC quantities	559.49	4773.6	3026.6	~~1059.4~~ 523.4	5117.3	141,239.7
12/22/82 F/L Letter to KCAPCD revising ERC quantities	560.1	4773.6	2825.3	~~1059.4~~ 523.4	4776.6	131,848.2
2/25/83(rev. 3/1/83) KCAPCD Letter to F/L revising ERC qtys.	560.1	4773.6	753.4	~~1059.4~~ 523.4	4776.6	131,848.2
Dedicated ERC's-- A to C's for Phase I	**(382.5)**	**(304.2)**	------	**(599.3)**	____	____
6/21/88 KCAPCD Letter--verifying ERC balance	177.6	4469.4	753.4	~~460.1~~	4776.6	131,848.2
12/22/89 ERC Donation to KCAPCD	------	(2673.9)	(753.4)	------	(2221.4)	(130,848.2)
Reinstatement--ERC quantities from expired A to C's	99.93	1.2	-----	119.9	------	--------
ERC Balance--for F/L future use/banking certificate	**277.5**	**1796.7**	-----	~~580.0~~ 44.0	**2555.2**	**1000.0**

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IX. RECOMMENDATION:

Issue ERC banking certificated to Frito-Lay subject to the conditions previously established for the used of these reductions as offsets i.e. that offsets be used only for the Frito-Lay snack foods processing plant at their present site and may not be sold or traded.

After public notice and review issue ERC Banking Certificates in the following amounts:

	Pounds/Day From Page _____			
PM10	SO2	NO2	VOC	CO
277.5	1796.7	44.0	2555.2	1000

	Pounds/Quarter				
	PM10	SO2	NO2	VOC	CO
1st Qt	24,975	161,703	3,960	229,968	90,000
2nd Qt	25,252	163,500	4,004	232,523	91,000
3rd Qt	25,530	165,296	4,048	235,078	92,000
4th Qt	25,530	165,296	4,048	235,078	92,000

X. BILLING INFORMATION:

Engineering time 34.0 hrs @ 33.40/hr	= $1135.60
Clerical time 1.0 hrs @ 17.46/hr	= $ 17.46
Subtotal	$1153.06
less filing fee	$ 650.00
Total Fees Due	$ 503.06

ENGINEERING EVALUATION OF APPLICATIONS FOR AUTHORITY TO CONSTRUCT

BREAKDOWN OF PROCESSING TIME

Company Name: Lance Erickson

Company Number: 6026 Project Number: 920416

Project Description: Bank Previously Recognized Reductions

Processing Dates, Including Preliminaries: 4/24 6/4 /23 4/24 4/27 6/18 6/22 7/23 7/24 7/27 8/12 8/13 8/14 8/19 8/20

PROCESSING ACTIVITY:	ACTIVITY TIME (HOURS):	INITAL:
Initial Contact: ___ telephone ___ in person		
Project Entry into System 36:	.5	LE
Preliminary Review:	6.5	LE
Organization/Familiarization:	8.0	LE
Project Description/Schematic/Equipment Listing:	1.0	LE
Listing of Applicable Rules:	-	
Design Review of Air Pollution Control Equipment:	-	
Calculation of Expected Emissions:	7.0	LE
Air Quality Impact Assessment Review (Modeling):	-	
Preparation of Emission Profiles:	-	
CEQA Review:	-	
Health Risk Assessment Review:	-	
Reworking of Application Due to Changes:	-	
Preparation of Rough Draft ~~A's to C~~ ERC	.5	LE
Preparation of Written Requests for Information:	1.0	LE
Telephone and Verbal Requests for Information:	1.0	LE
General Meetings with Applicant:	-	
System 36 Data Entry (Including Emissions):	.5	LE
Review Qualification for Banking:	8.0	LE
TOTAL TIME SPENT ON EVALUATION:	34.0	LE

Exhibit N

Powers Engineering

March 27, 2007

Ms. Gloria Smith
Adams Broadwell Joseph & Cardozo
601 Gateway Blvd., Suite 1000
South San Francisco, CA 94080

Subject: Big West CFP DEIR Is Deficient in Its Failure to Analyze Air-Cooled Heat Exchanger as an Alternative to Cooling Tower

Dear Gloria:

This letter summarizes my assessment of the viability of using air-cooled heat exchanger technology to minimize or eliminate many of the impacts associated with the proposed use of cooling towers in the CSP. The Big West CFP DEIR is deficient in its failure to incorporate use of air-cooled heat exchangers to avoid the significant negative impacts associated with the use of cooling towers in the CFP.

The DEIR asserts (p. 3-17) that "*air-cooling has been maximized where possible*." This statement implies that Big West is aware that use of air-cooling is inherently preferable to wet cooling. Yet two cooling towers are specified for the CFP, the (1) Alky cooling tower and (2) the "General Purpose" cooling tower. There is no indication in the DEIR that any air cooling is included in the scope of the CFP, despite the claim that "*air-cooling has been maximized where possible*." No attempt is made in the DEIR to justify in any quantitative fashion why cooling towers were selected over air-cooled heat exchangers. Each cooling tower will emit 2.76 tons per year of VOC and 1.05 tons per year of PM_{10}.

These two cooling towers will add 1,100,000 gallons per day of consumptive water use and generate 350,000 gallons per day of wastewater that will be disposed of via injection wells. Approximately 60 percent of the CFP water demand of 2,080.7 acre-ft per year (AFY) is associated with the cooling towers. Over 80 percent of the wastewater to be treated in the CFP "additional wastewater treatment facility" will be generated in the cooling towers in the form of blowdown water.

Use of Air-Cooled Heat Exchanger Mitigates Consumptive Water Use, Wastewater Disposal, and Air Emissions Impacts of Proposed Wet Cooling Towers

Table 1 is a comparison of the annualized cost of proposed 15,000 gpm cooling tower(s) and air-cooled heat exchanger alternative. The ancillary systems that must be built and operated as a result of the wet cooling tower selection are also included in the wet cooling tower cost estimate.

These ancillary systems include groundwater pumping cost to provide make-up water to the cooling towers, construction cost of an additional wastewater treatment facility to treat cooling tower blowdown, and construction cost of three reinjection wells for disposal of treated cooling tower blowdown. None of these ancillary systems are necessary with the air-cooled heat exchanger. All detailed assumptions and supporting calculations for the basecase cooling tower and related ancillary systems are provided in attached Table A-1.

The annualized cost of the air-cooled heat exchanger with a 20 ^{o}F approach temperature is essentially the same as that of the cooling tower when all ancillary cooling tower systems are considered. All detailed assumptions and supporting calculations for the: 1) air-cooled heat exchanger with a 10 ^{o}F approach temperature, and 2) air-cooled heat exchanger with a 20 ^{o}F approach temperature are provided in attached Table A-2 and Table A-3, respectively.

Selection of the air-cooled heat exchanger eliminates all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} are reduced with the air-cooled heat exchanger even though power demand of the air-cooled heat exchanger is incrementally higher than that of the cooling tower. The reason for this is that cooling tower VOC and PM_{10} emissions from circulating process water, generated by off-gassing (VOC) and aerosol drift (PM_{10}), are generated at a higher rate than air emissions from an offsite power station generating power for the air-cooled heat exchanger fans. A small amount of NO_x emissions, 0.18 tons per year for the air-cooled heat exchanger with a 20 ^{o}F approach temperature, are generated by offsite power sources supplying power to the air-cooled heat exchanger fans.[1] There are no NO_x emissions associated with the cooling towers.

Table 1. Cost Comparison: Wet Cooling Tower and Air-Cooled Heat Exchanger

Alternative	Annualized cost, $/year	Consumptive water use, (gallons/day)	Wastewater discharge, (gallons/day)	Air emissions, (tons/year)	Power consumption, kw
Cooling tower, 15,000 gpm	840,725	1,100,000	350,000	VOC: 2.76 PM_{10}: 1.05	474
Air-cooled HX, 20 ^{o}F approach	837,937	0	0	VOC: 0.05 PM_{10}: 0.12 NO_x: 0.18	1,074
Air-cooled HX, 10 ^{o}F approach	1,261,625	0	0	VOC: 0.09 PM_{10}: 0.23 NO_x: 0.34	1,611

[1] Increase in power demand between the AA HX with 20 ^{o}F approach and the cooling tower is 0.6 MW. Air emissions from this 0.6 MW power demand are pro-rated from emission estimates for PG&E's Gateway Energy Center per March 26, 2007 report of Dr. Phyllis Fox. Gateway has a projected on-line date of June 2009 which coincides with the projected completion date of the CFP. Air emissions associated with the 0.6 MW increase in power demand for AA HX with 20 ^{o}F approach are: NO_x = 0.18 tpy, VOC = 0.05 tpy, and PM_{10} = 0.12 tpy. Air emissions associated with the 1.137 MW increase in power demand for AA HX with 10 ^{o}F approach are: NO_x = 0.34 tpy, VOC = 0.09 tpy, and PM_{10} = 0.23 tpy.

Air-cooled heat exchangers are very similar to automotive radiators. Large fans are used to draw air across tubes containing the water being cooled. The minimum outlet temperature achieved by an air-cooled heat exchanger is limited by the ambient air temperature. The more conservative the air-cooled heat exchanger design, the more it "approaches" the design ambient air temperature. That is why the air-cooled heat exchanger with a 10 ^{o}F approach temperature is considerably more costly and energy intensive than the air-cooled heat exchanger with a 20 ^{o}F approach temperature. A description of air-cooled heat exchanger technology and how it compares to wet cooling towers is provided in Attachment 1 (Ecodyne MRM technical bulletin).

Cooling towers rely primarily on evaporation of a small portion of the circulating water in the tower, in the range of 2 percent, to reduce water temperature. It is this evaporation that creates the need for large amounts of cooling tower make-up water, as well as the need to "blow down" a certain amount of circulating water to prevent the buildup of solids beyond acceptable levels.

The theoretical limit of the temperature reduction achievable in a cooling tower is the ambient "wet bulb" temperature. This is the air temperature reduction that would be reached if dry ambient air was completely saturated with moisture. This effect is demonstrated by misting systems that are used for ambient cooling along storefront walkways in hot desert climates. The wet bulb temperature is generally 10 to 20 ^{o}F below the dry ambient temperature on hot days. This is the reason that wet cooling systems are able to reach lower cooling water outlet temperatures on hot days than comparably sized air-cooled systems.

The air-cooled heat exchangers identified in Table 1 will measure either 40 feet by 252 feet (20 ^{o}F approach) or 40 feet by 378 feet (10 ^{o}F approach), depending on the level of conservatism desired in the air-cooled heat exchanger design. The primary function of the cooling tower or the air-cooled heat exchanger in this CFP application is heat rejection. Achieving a minimum cooling water outlet temperature is generally not as critical in refinery process equipment cooling applications as it is in power generation applications.[2]

The DEIR (p. 3-17) states the cooling towers will be located outside the process unit areas to minimize exposure to flammable material). This concern for flammability indicates it is anticipated that the cooling towers will be made of wood or fiberglass.[3] The cooling tower material of construction is not specified in the DEIR. Air-cooled heat exchangers are made of galvanized steel and would not be subject to siting constraints due to concerns over flammability.

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[2] March 20, 2007 phone communication between B. Powers and J.A. Latimer, Puget Sound Refining Company and co-author of paper, *Optimizing Petroleum Refinery Cooling Water System*, 1999.

[3] January 13, 1993, standards interpretation, OSHA Standard 1910.106, *Fiberglass tanks for above and below ground storage of flammable and combustible liquids*. Fiberglass is considered to be a combustible material due to the flammability of the polyester resin used as a binder for the glass.

There is ample available space for installation of air-cooled heat exchanger(s) adjacent to the new CFP process units depicted in Figure 3-1, "Plot Plan."

Use of Air-Cooled Heat Exchangers Mitigates CFP Impacts on SWP Water

At maximum capacity, the CFP will require an additional 2,080.7 AFY of process water (DEIR, p. 4.5-29). Approximately 1,200 to 1,300 AFY of this additional water is associated with the consumptive water demand of the Alky and General Purpose cooling towers. See Table A-1. All of the replenishment water for this 1,200 to 1,300 AFY withdrawal will come from the State Water Project (SWP).

The CSP is located in Improvement District No. 4 (ID4). The ID4 was formed by the Kern County Water Association (KCWA) Board of Directors in 1971 to act as the wholesale provider of drinking water supply for portions of the metropolitan Bakersfield area. The ID4 has the ability to levy fees on groundwater pumping within its service area. The current fee schedule for 2005 would allow the ID4 to collect $30 per AFY for groundwater pumped from the refinery water supply aquifer (DEIR, p. 4.5-29).

The payment of groundwater pumping fees to the ID4 operational fund pays for the pumping of SWP water through the Cross Valley Canal. SWP water is banked within the groundwater recharge areas located approximately one mile southeast of the project. This replenishes the aquifer to reduce the impact of the CFP withdrawals on groundwater elevations.

Big West and the KCWA assume the SWP is an unlimited source of very inexpensive fresh water in identifying use of SWP water as adequate mitigation for aquifer withdrawals associated with the proposed cooling towers. Excessive transfers of Sacramento River Delta water via the SWP are an ongoing controversy in California.[4] KCWA treats SWP water as a free resource and will only charge Big West for the cost of pumping this water into the aquifer.

The fee of $30 per AF is an exceptionally low charge compared to what some other Southern California water users pay for SWP water. For example, the San Diego County Water Authority pays $427 per acre-foot to the Metropolitan Water District for a blend of raw water from the SWP and the Colorado River. See Attachments 2 and 3. If Big West were charged $427 per AF for 2,080.7 AF of aquifer recharge water from the SWP, the fee would be $888,459/yr, not $62,421/yr. A fee of this magnitude for SWP water would dramatically shift the economics in favor of air-cooled heat exchangers over cooling towers in the CSP.

Please feel free to call me at (619) 295-2072 or e-mail at bpowers@powersengineering.com if you have any questions about the contents of this letter.

[4] Los Angeles Times, *Another warning of Sacramento delta crisis*, February 8, 2007.

Best regards,

Bill Powers, P.E.

Bill Powers, P.E.

Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

tel: 619-295-2072
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Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

Parameter	Assumed Value	Reference
Cooling tower circulation rate, gpm	15,000	DEIR. Appendix E, .pdf pages 57 and 58.
Cooling tower heat rejection rate, MMBtu/hr	150	A circulating cooling water range of 20 ^{o}F is assumed. Range is the cooling tower inlet/outlet temperature difference.
Installed cost cooling tower, $	1,300,000	Base 1999 cost for 15,000 gpm FRP cooling tower with 10 ^{o}F design approach temperature: EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 2, Table 2-13, *Estimated Capital Costs of Cooling Towers*. Capital cost of increase from 1999 to 2007 is 45%, per March 21, 2007 e-mail from J. Padilla of SPX Cooling Technologies citing a 40 to 50% increase in cooling tower cost from 1999 to 2007. The 45% increase brings cooling tower cost to $1,300,000.
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest is 0.0944. This factor is multiplied by the capital cost to derive the annual expense associated with the capital investment.
Annual expense on capital investment, $/yr	$122,720	0.0944 x $1,300,000 = $122,720/yr.
Cooling tower evaporation + drift rate, gpm	270	Approximately 1.8 percent of total cooling tower circulating water flow assuming a range of 20 ^{o}F. Source: Cooling Tower Fundamentals, 2nd Edition, Figure 40 – *Cycles of Concentration*, p. 31, 1998. Attachment A1.
Cooling tower blowdown rate to WWT, gpm	120	Assume 3 cycles of concentration is the design target for cooling tower, therefore blowdown rate is 0.8% of tower circulation rate. Source: Cooling Tower Fundamentals, 2nd Edition, Figure 40 – *Cycles of Concentration*, p. 31, 1998. Attachment A1.
Make-up cooling tower waterflow, gpm	390	Sum of evaporative, drift, and blowdown cooling tower losses. On continuous annual basis 390 gpm equals 631 AFY.
Depth to usable groundwater, feet	500	DEIR, p. 4.5-8. Water well construction and development reports filed with the California Division of Oil, Gas and Geothermal Resources are available for wells #4a and #4b developed in Area 1 of the refinery. Well #4a was drilled to a depth of 792 feet and perforated for water supply from 500 feet to 680 feet. Well #4b was filed on September 30, 1977, drilled to a depth of 775 feet, and perforated for water supply from 400 feet.

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

Equation for pump power required, hp	-	Pump motor hp = $\frac{\text{(gpm)(feet hydraulic head)}}{3{,}960\ (\eta_p)}$ Source: Mechanical Engineering Review Manual, 6th Edition, 1980. Chapter 6 – Hydraulic Machines, p. 6-30.
Pump efficiency, η_p	0.70	Default pump efficiency value.
Pump power required for supplying make-up water to cooling tower, hp	70	Groundwater is pumped from depth of 500 feet. Pump hp = $\frac{\text{(390 gpm)(500 feet head)}}{3{,}960\ (0.70)}$ = 70 hp
Distance from alky unit to additional WWT, feet	3,000	Review of plot plan, DEIR Figure 3-1.
Distance from additional WWT to injection wells, feet	500	Review of plot plan, DEIR Figure 3-1. This is the average distance from the additional WWT for the three new reinjection wells.
Friction loss in pipe, hydraulic feet per 1,000 feet	6.1	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, Table 3-17, *Cooling Water Pumping Head and Energy*. Assume mean pipe velocity of 7.7 feet/second and friction head loss rate of 6.1 feet per 1,000 feet of pipe.
Cooling tower to injection wells total pipe friction loss, hydraulic feet	21.4	Total pipe distance from cooling tower(s) to injection wells via the additional WWT is 3,500 feet on average. 6.1 feet/1,000 feet x 3,500 feet = 21.4 hydraulic feet. Wastewater flow is 60 gpm.
Pump power required for moving cooling tower blowdown through pipe to WWT and to injection wells, hp	1	Pipe friction loss hp requirement = $\frac{\text{(120 gpm)(21.4 feet head)}}{3{,}960\ (0.70)}$ = 1 hp
Cooling tower static hydraulic head, feet	25	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, p. 3-25.
Pump power required for circulating water through cooling tower, hp	135	Assume groundwater is pumped from depth of 250 feet as groundwater begins at 200 foot depth. Pump motor hp = $\frac{\text{(15,000 gpm)(25 feet)}}{3{,}960\ (0.70)}$ = 135 hp
Injection well pump motor power, hp	129	Average oilfield well motors in California, both producer and injection wells, is 43 hp. Source: *CEC-EPRI: Optimization of Electric Energy Consumption in Marginal California Oilfields*, Figure 4-7, Distribution of Motor Sizes, January 2003, p. 4-5.

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		The project will inject up to 10,000 barrels/day (DEIR, p. 4.5-33) of treated wastewater to a depth of approximately 4,000 feet (DEIR, p. 4.5-37)
Cooling tower fan power requirement, hp	300	EPA CWA Section 316(b) *Phase I Technical Development Document for New Facilities*, Chapter 3, Table 3-16, *Wet Tower Fan Power Energy Penalty*. Assume Case #1, cooling tower with design approach of 11 ^{o}F and design heat rejection of 150 MMBtu/hr.
Total power requirement for cooling tower, hp	635	70 hp + 1 hp + 135 hp + 129 hp + 300 hp = 635 hp
Total power requirement for cooling tower, kw	474	1 hp = 0.746 kw. Therefore, 635 hp = 474 kw
Wholesale cost of California electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html
Annual cost of electric power, $/yr	290,657	474 kw x $0.07/kwh x 8,760 hr/yr = $290,657/yr
O&M cost of wastewater treatment for cooling tower blowdown, $/1,000 gallons	2.00	EPA Control Cost Manual, 6th Edition, Chapter 2, *Cost Estimation: Concepts and Methodology*, 2002, p. 2-33. This is an estimated of fixed (labor) and variable (chemicals, energy, etc.) expenses, and does not include amortized treatment plant capital cost. See Attachment A2.
O&M cost of treating cooling tower blowdown, $/day	$346	$2.00/1,000 gallons x 120 gallons/minute x 60 minutes x 24 hours = $259/day
O&M cost of treating cooling tower blowdown, $/year	$126,290	$346/day x 365 day/year = $126,290/year
Charge to replenish aquifer under Flying J with State Water Project water, $/yr	$19,038	(DEIR, p. 4.5-29) Improvement District 4 (ID4) has the ability to levy fees on groundwater pumping within its service area. Based on recommendations made in the 2004, the current fee schedule for 2005 would allow the ID4 to collect $30 per AFY for groundwater pumped from the refinery water supply aquifer. The payment of groundwater pumping fees to the ID4 Operational Fund will pay for the pumping of State Water Project (SWP) water through the Cross Valley Canal. SWP water is banked within the groundwater recharge areas located approximately one mile southeast of the

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		project. At maximum capacity, the CFP will require an additional 2,080.7 acre-feet/day (AFY) of process water. At maximum production, the increased revenue to ID4 would be $62,421 per year based on the $30 per AF groundwater pumping fee. At a withdrawal rate of 390 gpm per cooling tower, the two cooling towers represent a maximum annual withdrawal of 1,261AFY, or 61% of the total withdrawal of 2,080.7 AFY. Therefore the aquifer recharge fee per cooling tower is ($62,421)(0.61/2) = $19,038/yr. It is of note that the charge of $30 per AFY is an exceptionally low charge compared to what some other Southern California water users pay for SWP water. For example, the San Diego County Water Authority pays $427 per acre-foot to the Metropolitan Water District for a blend of raw water from the SWP and the Colorado River. See Attachment 2. If Flying J were charged a comparable fee for 2,080.7 AFY of aquifer recharge water from the SWP, the fee would be $888,459/yr, not $62,421/yr.
Capital cost of groundwater pumping well(s)	?	No information is provided in the DEIR on the number of groundwater pumping wells that will be added to the facility to increase groundwater pumping by up to 2,080.7 AFY.
Capital cost of additional wastewater treatment facility, $	3,500,000	Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). 10,000 BPD is 420,000 gallons/day. Assume additional wastewater treatment facility is designed to treat 500,000 gallons/day. <u>Source of cost estimate</u>: SEWRPC Technical Report No. 43 – *State-of-the-Art of Water Supply Practices, Chapter 3: Surface Water Treatment Technologies*, revised November 28, 2006, *Table III-3: Construction Costs for Various Size Treatment Facilities,* $6.93 per gpd of capacity for 0.5 Mgd facilities. See Attachment A3. This estimate for facility designed to process surface or groundwater to drinking water level does not necessarily reflect the mix of treatment processes that will be used at the Flying J additional wastewater treatment facility. Flying J will be treating process water for onsite recycling or injection. However, no information is provided in

Table A-1. Annualized Cost of 15,000 gpm Cooling Tower and Ancillary Systems

		the DEIR on the water treatment processes that will be utilized.
Annualized capital cost of additional wastewater treatment facility, $	330,400	0.0944 x $3,500,000 = $330,4000/yr
Annualized capital cost of additional wastewater treatment facility per cooling tower, $	165,200	Total cooling tower blowdown is 345,600 gallons/day, equivalent to 8,229 AFY. Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). The cooling towers will generate for more than 80% of the wastewater to be treated. Assess entire capital cost of additional wastewater treatment facility to the cooling towers. Assess ½ of the capital cost of the additional wastewater treatment facility to each cooling tower.
Capital cost of three injection well(s)	2,475,000	Well depth is 4,000 feet (DEIR, p. 4.5-37). Estimated day rig rental rate in the Central Valley is $23,000/day. Turnkey daily drilling cost including auxiliaries is $50,000 to 60,000/day. 30-day timeline is reasonable drilling and completion schedule for 10,000-foot well. Source: phone communication between B. Powers and Don Cleveland, Nabors Drilling, Bakersfield, July 15, 2005. Assume for CFP that each injection well requires 15 days for drilling and completion. Turnkey daily cost is $55,000/day. Cost to drill each well is 15 days x $55,000/day = $825,000. Three (3) wells x $825,000/well = $2,475,000.
Annualized capital cost of reinjection wells, $/yr	$233,640	0.0944 x $2,475,000 = $233,640/yr
Annualized capital cost of reinjection wells per cooling tower, $/yr	$116,820	Blowdown from cooling towers that must be treated and reinjected is 240 gpm total, 120 gpm per cooling tower. Total cooling tower blowdown is 345,600 gallons/day, equivalent to 8,229 AFY. Big West is requesting that USEPA grant an injection well rate increase of 10,000 BPD for the refinery (DEIR, 4.5-33). Treated blowdown represents more than 80% of total water to be injected. Therefore all three reinjection wells are necessary for cooling tower blowdown disposal. Assess ½ the capital cost of the three reinjection wells to each cooling tower.
Wet cooling tower annualized direct and indirect total cost, $/year	**840,725**	$122,720/yr + $290,657/yr + $126,290/yr + $19,038/yr + $165,200/yr + $116,820 = $840,725/yr

Table A-2. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 10 ^{o}F Approach Temperature

Parameter	Assumed Value	Reference
Installed cost cooling tower, $	2,900,000	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME, 150 MMBtu/hr heat rejection, cooling water temperature reduction from 130 ^{o}F to 110 ^{o}F, 10 ^{o}F approach, 100 ^{o}F ambient design temperature. $2,430,000 equipment cost. See Attachments A4 and A5. Installation of modular AA HX units adds 10 to 25% to equipment cost, per March 23, 2007 e-mail from J. Schulz of SMITHCO/Anderson & Associates. Assume 20% installation multiplier. Installed cost is $2,430,000 + $486,000 = $2,914,000.
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest.
Annual payment on capital investment, $/yr	$273,760	0.0944 x $2,900,000 = $273,760/yr.
AA HX, number of modules ("bays")	27	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of bay, width feet x length feet	14 x 40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification**.**
Dimensions of AA HX array, width feet x length feet	378 x 40	27 bays would be positioned side-by-side to form continuous unit.
Number of fans per bay	2	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Power demand of each fan, hp	40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Design approach temperature, ^{o}F	10	The design temperature for Bakersfield is 100 ^{o}F. Source: Ecodyne, Weather Data Handbook, 1980, p. 12-13. AA HX is conservatively designed to reduce water outlet temperature to 110 ^{o}F at design ambient temperature on design 100 ^{o}F summer day.
Total HX fan power, hp	2,160	27 x 2 x 40 hp = 2,160 hp
Total HX fan power, kw	1,611	2,160 hp x 0.746 = 1,611 kw
Wholesale cost of electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html

Table A-2. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 10 ^{o}F Approach Temperature

Annual cost of AA HX electric power, $/yr	987,865	1,611 kw x $0.07/kwh x 8,760 hr/yr = $987,865/yr
10 ^{o}F approach AA HX annualized total cost, $/yr	**1,261,625**	$273,760/yr + $987,865/yr = $1,261,625/yr

Table A-3. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 20 ^{o}F Approach Temperature

Parameter	Assumed Value	Reference
Installed cost cooling tower, $	1,900,000	Increase of approach temperature from 10 ^{o}F to 20 ^{o}F, a cooling water temperature reduction from 140 ^{o}F to 120 ^{o}F, would reduce size and cost of AA HX by one-third, per March 21, 2007 phone conversation with Wes Cryster, application engineering manager, Ecodyne MRM. The 1/3 reduction in AA HX size and cost is applied to the basecase SMITHCO Engineering estimate. A 20 ^{o}F approach temperature is a common approach temperature for AA HX applications. See Attachment 1 (Ecodyne MRM brochure).
Capital recovery factor (CRF)	0.0944	CRF for 20-year, 7% interest.
Annual payment on capital investment, $/yr	179,360	0.0944 x $1,900,000 = $179,360/yr.
AA HX, number of modules ("bays")	18	Adjusted (by B. Powers) March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification.
Dimensions of bay, width feet x length feet	14 x 40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification.
Dimensions of AA HX array, width feet x length feet	252 x 40	18 bays would be positioned side-by-side to form continuous unit.
Number of fans per bay	2	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Power demand of each fan, hp	40	March 21, 2007 SMITHCO Engineering, Inc. preliminary design specification T004-01ME
Design approach temperature, ^{o}F	20	The design temperature for Bakersfield is 100 ^{o}F. Source: Ecodyne, Weather Data Handbook, 1980, p. 12-13. AA HX is designed to reduce water outlet temperature from 140 ^{o}F to 120 ^{o}F at design ambient temperature.
Total HX fan power, hp	1,440	18 x 2 x 40 hp = 1,440 hp
Total HX fan power, kw	1,074	1,440 hp x 0.746 = 1,074 kw
Wholesale cost of electricity, $/kwh	0.07	Source: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html

Table A-3. Annualized Cost of Air-Cooled Heat Exchanger (AA HX) Designed for 20 ^{o}F Approach Temperature

Annual cost of AA HX electric power, $/yr	658,577	1,074 kw x $0.07/kwh x 8,760 hr/yr = $658,577/yr
20 ^{o}F approach AA HX annualized total cost, $/yr	**837,937**	$179,360/yr + $658,577/yr = $837,937/yr

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AMENDED APPLICATION FOR CERTIFICATION FOR THE HYDROGEN ENERGY CALIFORNIA PROJECT

Docket No. 08-AFC-08A
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(Revised 05/10/2013)

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

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DECLARATION OF SERVICE

I, Andrea Sanchez, declare that on May 30, 2013, I served and filed copies of the attached Comments on Preliminary Determination of Compliance for Hydrogen Energy California, Facility # S-7616, Project # S-1121903 dated May 30, 2013. This document is accompanied by the most recent Proof of Service, which I copied from the web page for this project at: http://www.energy.ca.gov/sitingcases/hydrogen_energy/.

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

(C*heck one*)

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

_x__ I e-mailed the document to all e-mail addresses on the Service List above and personally delivered it or deposited it in the U.S. mail with first class postage to those persons noted above as “hard copy required”; **OR**

___ Instead of e-mailing the document, I personally delivered it or deposited it in the U.S. mail with first class postage to all of the persons on the Service List for whom a mailing address is given.

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

Dated: May 30, 2013 /s/Andrea Sanchez