CECP SUPPLEMENTAL EVIDENTIARY HEARING

DIRECT TESTIMONY OF MATTHEW D. ZINN, PARTNER, SHUTE, MIHALY & WEINBERGER LLP, OUTSIDE COUNSEL TO THE CITY OF CARLSBAD REGARDING THE ENVIRONMENTAL PROTECTION AGENCY'S PREVENTION OF SIGNIFICANT DETERIORATION PERMITTING PROCESS

Q1. Please state your name and position.

A1. My name is Matthew D. Zinn. I am a partner in the law firm of Shute, Mihaly, & Weinberger LLP, located in San Francisco, California. I was retained by the City of Carlsbad to advise the City about EPA's treatment of the Carlsbad Energy Center Project ("CECP") under the federal Clean Air Act and to represent it in litigation challenging EPA's failure to require a Prevention of Significant Deterioration ("PSD") permit for the CECP. My curriculum vitae is attached to this testimony.

Q2. Describe the City of Carlsbad's participation in the Environmental Protection Agency's permitting proceedings for the CECP.

A2. In 2007, Applicant proposed constructing two natural-gas-fired combined cycle gas turbines at a location adjacent to the existing Encina Power Station ("EPS") and decommissioning three existing boilers at EPS. On June 5, 2009, Applicant requested that EPA determine that this project would not trigger the permit requirements of the PSD program under the Clean Air Act. A physical change to an existing major source requires a PSD permit if it results in both (a) a significant emissions increase, and (b) a significant net emissions increase of any PSD pollutant. 40 C.F.R. § 52.21(a)(2)(iv), (b)(3).

To determine whether a modification results in a net increase in emissions, EPA subtracts any emission reductions "contemporaneous" with the modification. 40 C.F.R. § 52.21(b)(3). To calculate reductions, EPA must determine the baseline emissions for the existing source. The higher the baseline emissions, the larger the apparent reduction associated with the modification, and the less likely the modification would reach the permit-triggering thresholds established in 40 C.F.R. § 52.21(b)(23). To calculate the baseline, the applicant generally must use the average rate of actual emissions "during any consecutive 24-month period . . . within the 5-year period immediately proceeding . . . actual construction." 40 C.F.R. § 52.21(b)(48)(i).

However, the PSD regulations also carve out an exception to this five-year "look-back" period for situations in which irregular occurrences interrupt normal operations. That exception authorizes the EPA Administrator to "allow the use of a different period upon a determination that it is more representative of normal source operations." *Id*. EPA guidance documents indicate that this exception is to be used in exceptional circumstances that severely affect source operations, such as strikes and natural disasters.

Applicant argued to EPA that it should be permitted to use the period from May 2003 to April 2005 as a baseline, which was outside the five-year look-back window, but it did not cite any such exceptional circumstance. The City promptly notified EPA that Applicant was improperly relying on the exception to artificially inflate baseline emissions, given that emissions at EPS had been decreasing steadily since 2004. The City urged EPA to select baseline emissions from the five-year period proceeding construction, which more accurately reflected current normal operating conditions and which would require that the CECP obtain a PSD permit for NO_x.

Instead, on October 13, 2010, EPA issued a determination that the PSD permit requirement did not apply to the CECP ("non-applicability determination"), based on its conclusion that the exception to the look-back period would apply. *See* Exhibit 456. The determination also provided that if Applicant did not begin construction on the CECP by June 30, 2011, EPA would require "a new analysis and determination." *Id.* at 2.

In response, the City filed a petition for review of the non-applicability determination in the Ninth Circuit. In the course of litigation, the City made clear that it was challenging EPA's application of the look-back period exception.

Because Applicant did not begin actual construction by June 30, 2011, the non-applicability determination expired. On July 18, 2011, EPA confirmed in a letter to Applicant that the determination had expired. *See* Exhibit 457. EPA also adopted the argument that the City had been making since Applicant's initial proposal in 2009. The letter states that "the analysis contained in [the determination] was made in error" and that "neither the overall determination nor the rationale and analysis contained therein can be relied upon to undertake actions related to [the CECP]." *See id.* at 1.

Q3. Describe how the PSD permitting process is likely to apply to the CECP going forward.

A3. EPA's rescission of the non-applicability determination means that Applicant will need to either request a new non-applicability determination or apply for a PSD permit. Applicant has not yet applied to EPA for either. Because Applicant did not begin actual construction on the CECP prior to June 30, 2011, the CECP will now be subject to amendments to the PSD regulations that incorporate greenhouse gases ("GHGs") as a regulated pollutant. *See* 40 C.F.R. § 52.21(b)(49), (50); Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010). A source making a major modification of an existing source must obtain a PSD permit for GHG emissions if the modification would result in a net emissions increase of 75,000 tons CO_{2e}/year or more. 40 C.F.R. § 52.21(49)(v)(b).

Applicant's testimony reveals that the CECP will result in significant increases in GHGs. Applicant's Supplemental Testimony at 13 (reporting CECP emissions of 932,630 tons/year). Although these increases do not appear to reflect the emission reductions associated with decommissioning of EPS Units 1, 2, and 3, it is highly unlikely that such decommissioning would reduce the increased GHG emissions associated with the CECP to less than the PSD significance threshold of 75,000 tons/year. Accordingly, Applicant almost certainly will need to apply for a PSD permit that incorporates limits on GHG emissions.[1]

Although Applicant may continue to argue that any PSD permit for the CECP need not incorporate limits on NO_X emissions, EPA is also likely to require the permit to include such limits. EPA's admission of error in its July 18, 2011 rescission of the October 13, 2010 non-applicability determination indicates that the Agency has repudiated its prior determination of the proper baseline for calculating CECP's net increase in NO_X emissions. *See* Exhibit 457 ("In withdrawing this PSD applicability determination as moot, we also note that we have concluded that the analysis contained in it was made in error. As such, neither the overall determination nor the rationale and analysis contained therein can be relied upon to undertake actions related to the CECP or any other facility. In revoking this particular analysis, EPA emphasizes that there still may be specific permitting circumstances in which EPA may use [its] discretion . . . to select a different period for determining the baseline actual emissions, but the use of such discretion will be based on the particular facts of the permitting situation under consideration."). Accordingly, it is doubtful that EPA would again accept Applicant's argument that emissions in the May 2003 to April 2005 period represent the proper baseline for evaluating the CECP's net emissions increase.

Indeed, the emissions data for EPS in the year since the 2010 non-applicability determination likely will only confirm EPA's error in relying on 2003-05 emissions as the baseline. The clear trend in emissions since 2006 has been downward, and the most recent data, and any data to come before Applicant submits a PSD application, are likely to confirm this trend. This data is likely to reinforce the conclusion that the 2003 to 2005 period is not "more representative" of normal source operations than would be a two-year period during the ordinary look-back period.

Regardless, the PSD permitting process is a lengthy one. Indeed, by Applicant's own account, the process is likely to take approximately two years to generate a final permit, and an appeal of that permit to the Environmental Appeals Board could take as long as a year.[2] Applicant's Supplemental Testimony at 17. If the issuance of the permit results in litigation, as did the non-applicability determination, the timeline would be even longer. This timeline is inconsistent with Applicant's suggestion that it could begin construction of the CECP in 2012, which appears to be based on an assumption that no PSD permit will be required. *See id.* at 13. Based on Applicant's own estimates, it appears that construction could not begin before 2014 at the earliest.

---

[1] EPA's new GHG regulations have been challenged in the D.C. Circuit. *See Coalition for Responsible Regulation, Inc. v. EPA*, No. 09-1322 (D.C. Cir. filed Dec. 10, 2010). Although the regulations remain effective pending a decision in the case, the court's decision could affect Applicant's responsibility to obtain a PSD permit.

[2] Applicant's time estimate is reasonable: for the Palmdale Hybrid Power Project cited in Applicant's Supplemental Testimony, a PSD permit application was filed in March 2009, and EPA issued the final permit in October 2011.

If Applicant's estimate of construction in 2012 is meant to imply that it could begin construction before obtaining a PSD permit, it is incorrect. A PSD permit is a *preconstruction* permit, not merely a *preoperation* permit. The PSD permit requirement is triggered by beginning "actual construction" of, in this case, a major modification of an existing source. *See* 40 C.F.R. § 52.21(a)(2)(iii); *Sierra Club v. Otter Tail Power Co.,* 615 F.3d 1008, 1014-15 (8th Cir. 2010) ("[T]he PSD requirements are conditions of construction, not operation."). Failure to obtain the permit prior to beginning construction may result in an enforcement action brought by a state regulatory authority, EPA, or a citizen plaintiff. *See* 42 U.S.C. §§ 7413(a)(3), 7477, 7604(a)(3). Accordingly, Applicant must obtain the permit before beginning construction of the CECP, not merely before the facility begins operation. Construction is thus likely two or more years in the future.

Q4. What conditions is EPA likely to impose on the CECP as part of the PSD permitting process?

A4. It is speculative to predict what conditions EPA may impose on issuance of a PSD permit for the CECP. The permit would require CECP to comply with emission standards for the pollutants that are covered by the permit. Those standards are established by determining the Best Available Control Technology ("BACT") for the permitted source and the emission levels that would result from the implementation of that control technology. BACT is determined on a case-by-case basis; EPA's determination of what constitutes BACT for a particular source is thus based on the specific circumstances of *that* source. *See* EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* ("*EPA Guidance*") at 17. In addition, BACT changes as innovations in pollution control technology occur. Thus, BACT for a particular emissions source changes over time. *EPA Guidance* at 35. As a result, it is difficult, and speculative, to attempt to predict in advance what requirements EPA will impose on any particular source.

In this instance, EPA will likely require a permit that covers both NO_X and GHG emissions. The PSD program only began to address GHG emissions in January of this year. As a result, EPA's experience is very limited in permitting new major sources or major modifications that involve significant GHG emissions. Indeed, the Applicant supports its conclusion that CECP is "expected to comply with BACT requirements for GHG" by comparing CECP to only one other project: the Palmdale Hybrid Power Project.

Contrary to Applicant's assertions, the PSD permit issued for the Palmdale Hybrid Power Project fails to support this conclusion. According to Applicant's testimony, the projected GHG emission levels at CECP—890 lbs CO_2/MWh—would exceed the allowable levels set forth in the Palmdale permit—774 lbs CO_2/MWh—by approximately 15 percent. Applicant's Supplemental Testimony at 15. The heat rate for the combustion turbines at CECP also indicate that they are less efficient than the turbines used at Palmdale. *Compare* CECP PMPD, Greenhouse Gas Emissions, at 12 (7,147 Btu/kWh) *with* Palmdale PMPD, Greenhouse Gas Emissions, at 12 (6,285 Btu/kWh to 6,970 Btu/kWh, depending on solar operation). Applicant has not explained this discrepancy or identified what changes to the project would be required to allow it to comply with the BACT standard incorporated into the Palmdale permit.

Although Applicant characterizes these emissions and heat efficiencies as “similar” (Applicant’s Supplemental Testimony at 15), EPA contradicts this conclusion in recent comments on a proposed PSD permit for a natural-gas-fired combustion turbine project in Utah. *See* Exhibit 458. In an application to the Utah Department of Environmental Quality for a PSD permit, the applicant (Pacficorp) concluded that the heat rate of its project was “similar” to that of the Russell City Energy Center, which voluntarily implemented BACT for GHG emissions, even though the efficiency of the Pacificorp facility would be one percent below that at the Russell City project. EPA requested that the State “explain why a lower energy efficiency than [the Russell City project], on an output basis, could still satisfy BACT.” Given that the turbines at CECP are nearly 14 percent less efficient than those at Palmdale, it is not certain that CECP, as currently proposed, would comply with the BACT standard.

Q5. Are you sponsoring any exhibits?

A5. Yes. Exhibit 456, an EPA letter with the subject, “PSD Determination for the Carlsbad Energy Center Power Project”; Exhibit 457, an EPA letter with the subject, “New PSD Applicability Determination Analysis for the Carlsbad Energy Center Power Project”; and Exhibit 458, an EPA letter with the subject, “Comments on Intent-to-Approve for Pacificorp Lake Side Power Plant, Block #2.”

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

12/6/11
Date

MATTHEW D. ZINN

259518.1

MATTHEW D. ZINN

Shute, Mihaly & Weinberger LLP
396 Hayes St., San Francisco, CA 94102
415.552.7272 (voice) 415.552.5816 (fax)
zinn@smwlaw.com

EDUCATION

UNIVERSITY OF MICHIGAN LAW SCHOOL

J.D. *magna cum laude*, May, 1999.

Michigan Law Review, Senior Editorial Board (Note Editor), Volume 97
Order of the Coif
Book Awards: Torts, Federal Courts
Scholarly Writing Award, 2000
Honorary Membership, American Society of Writers on Legal Subjects (Scribes), 1999
Research Assistant, Prof. Sherman Clark, 1997 (112 HARV. L. REV. 434 (1998))
Environmental Law Society, Vice President, 1997-98

UNIVERSITY OF MICHIGAN SCHOOL OF NATURAL RESOURCES & ENVIRONMENT

M.S. (Environmental and Natural Resources Policy), December, 1999.

Graduate Student Instructor, Environmental Law, 1998, 1999
Joseph L. Sax Fellow, 2000
Merit Awards, 1997-98, 1998-99

UNIVERSITY OF CALIFORNIA AT SANTA CRUZ

B.A. (Politics and Sociology), December, 1994.

Honors in Politics, Honors in Sociology, College Honors (Stevenson College)

WORK EXPERIENCE

Shute, Mihaly & Weinberger LLP, San Francisco, CA
Partner — Jan. 2009 to Present
Associate — 2001-08

Boalt Hall School of Law, University of California, Berkeley, CA
Environmental Law Research Fellow — Spring 2006

Chief Judge John M. Walker, Jr., United States Court of Appeals for the Second Circuit, New Haven, CT — 2000-01
Law Clerk

Georgetown Environmental Law and Policy Institute, Washington, DC
Consulting Researcher — 2000

McCutchen, Doyle, Brown & Enersen, LLP, San Francisco, CA
Summer Associate — Summer 1999

United States Department of Justice, Washington, DC
Honors Program Summer Intern, Environment & Natural Resources Division — Summer 1998

Arnold & Porter, Washington, DC
Summer Associate Summer 1998

National Audubon Society, Washington, DC
Legal Intern Summer 1997

The White House, Office on Environmental Policy, Washington, DC
Assistant to William Stelle, Associate Director for Natural Resources 1994

PUBLICATIONS & PRESENTATIONS

Participant, Environmental Law Institute, Working group on addressing cumulative impacts to coasts and oceans (2009-2011)

Going, Going, Gone: Mitigating the Loss of California's Farm Land, panel presentation at the State Bar of California Environmental Law Section Environmental Law Conference at Yosemite (Oct. 23, 2011)

Penn Central *Unleashed? Finding Takings in the Post-*Lingle *Era*, paper presented at the Vermont Law School's Conference on Litigating Takings and Other Legal Challenges to Land Use and Environmental Regulation, Berkeley Law School (Nov. 5, 2010)

Climate Adaptation and Mitigation in Land Use Regulation, symposium presentation, *Living with Climate Change: Legal Challenges in a Warmer World*, Widener University School of Law (Apr. 18, 2008)

Moderator, *To Trade or Not to Trade: Pros and Cons of a Market-based Regulatory Approach to Climate Change Mitigation*, Planning and Conservation League Annual Symposium (Jan. 12, 2008)

Moderator, Panel on Federal Administrative and Congressional Initiatives, *The Domestic Response to Global Climate Change: Federal, State, and Litigation Initiatives*, USF School of Law (Mar. 31, 2007)

Adapting to Climate Change: Environmental Law in a Warmer World, 34 ECOL. L. Q. 61 (2007)

Flogging a Dead Horse? Threshold Limitations on Substantive Due Process Challenges to Land Use Controls, paper presented at the Georgetown Environmental Law & Policy Institute's Litigating Regulatory Takings Conference, U.C.L.A. School of Law (Oct. 15, 2004)

Policing Environmental Regulatory Enforcement: Cooperation, Capture, and Citizen Suits, 21 STAN. ENVTL. L.J. 81 (2002)

California's New Water-Supply Planning Statutes: Selected Problems of Application, 2002 CAL. ENVTL. L. REP. 123

Contributing co-author of 2000 update to ZYGMUNT J.B. PLATER, ROBERT ABRAMS, WILLIAM GOLDFARB & ROBERT GRAHAM, ENVIRONMENTAL LAW AND POLICY: NATURE, LAW, AND SOCIETY (2d ed. 1998)

Note, *Ultra Vires Takings,* 97 MICH. L. REV. 245 (1998)

SIGNIFICANT LITIGATION EXPERIENCE

- Defended the City of Goleta in the Ninth Circuit in regulatory takings litigation challenging the City's mobilehome rent control ordinance, *Guggenheim v. City of*

Goleta, 638 F.3d 1111 (9th Cir. 2010) (*en banc*), *cert. denied,* 131 S. Ct. 2455 (May 16, 2011);

- Defended the South Coast Air Quality Management District in litigation in the Court of Appeal and California Supreme Court challenging the District's regulation of air emissions from paints (ongoing);
- Defended the County of Stanislaus against litigation at the trial and appellate levels filed by the Building Industry Association of Central California challenging the County's adoption of a program to mitigate for the conversion of farmland to residential use, *Bldg. Indus. Ass'n of Cent. Cal. v. County of Stanislaus*, 190 Cal. App. 4th 582 (2010);
- On behalf of the Sonoma Land Trust negotiated a settlement of litigation seeking to enforce an agricultural conservation easement against the owner of the property subject to the easement;
- Defended the South Coast Air Quality Management District in litigation at the trial and appellate level challenging the District's regulation of air emissions from oil refineries, *W. States Petroleum Ass'n v. S. Coast Air Quality Mgmt. Dist.*, 136 Cal. App. 4th 1012 (2006);
- On behalf of the State Water Resources Control Board, negotiated settlement of several lawsuits filed by the federal Bureau of Reclamation and various water contractors challenging enforcement of water quality standards in the San Francisco Bay Delta;
- Wrote amicus brief in the United States Supreme Court on behalf of the National Council of Churches and other religious groups in *Massachusetts v. EPA,* 549 U.S. 497 (2007), supporting the petitioners' successful challenge to EPA's refusal to regulate motor vehicle emissions of greenhouse gases;
- Participated in drafting of respondent's brief for the City and County of San Francisco in the United States Supreme Court in an action challenging the City's affordable housing ordinance, *San Remo Hotel v. City & County of San Francisco,* 545 U.S. 323 (2005);
- Defended the City of Walnut at the trial and appellate levels in multiple lawsuits filed by developer challenging the City's decisions to protect habitat for the threatened California gnatcatcher;
- Defended the City of Saratoga in challenge by property owner to expenditure of public funds for assessment district;
- Defended the City of Pacifica in challenge by property owner to denial of tentative subdivision map; and
- As a law student, participated in drafting of amicus briefs in Michigan and California Supreme Courts on behalf of National Audubon Society in support of defendant public agencies in two regulatory takings cases, *K & K Constr., Inc. v. Dep't of Natural Res.*, 575 N.W.2d 531 (Mich. 1998), and *Landgate, Inc. v. Cal. Coastal Comm'n*, 17 Cal. 4th 1006 (1998).

MEMBERSHIPS/
ADMISSIONS: Bar of the State of California (Environmental Law Section), U.S. District Court for the Northern District of California, U.S. District Court for the Eastern District of California, U.S. Court of Appeals for the Ninth Circuit, U.S. Court of Appeals for the Federal Circuit, U.S. Supreme Court

EXHIBIT 456

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

October 13, 2010

George L. Piantka, P.E.
Carlsbad Energy Center LLC
1817 Aston Avenue, Suite 104
Carlsbad, CA 92008

Subject: PSD Determination for the Carlsbad Energy Center Power Project

Dear Mr. Piantka:

This letter is in response to your analysis submitted to the United States Environmental Protection Agency (EPA) on June 5, 2009, as well as additional information submitted to EPA to supplement this analysis. The analysis provides information on determining whether the proposed Carlsbad Energy Center Project (CECP), which will be located in the city of Carlsbad, in San Diego County, will trigger Prevention of Significant Deterioration (PSD) permit requirements.

EPA has reviewed the information submitted. Based on our review, we conclude that the CECP is not a major modification and is not subject to PSD permit requirements. Enclosed is our analysis.

If you have any questions, please contact Shaheerah Kelly of the Air Permits Office at (415) 947-4156.

Sincerely,

Deborah Jordan
Director, Air Division

Enclosures: (1) PSD Applicability Analysis for the Carlsbad Energy Center Project
(2) Attachments A, B, C, & D

cc: Robert Kard, San Diego Air Pollution Control District (w/ enclosures)
Steven Moore, San Diego Air Pollution Control District (w/ enclosures)
Tom Andrews, Sierra Research (w/ enclosures)
Mike Monasmith, California Energy Commission (w/ enclosures)
Will Walters, Aspen Environmental Group (w/ enclosures)
Joe Garuba, City of Carlsbad (w/ enclosures)

PSD Applicability Analysis for the Carlsbad Energy Center Project

I. Introduction

Carlsbad Energy Center LLC (Applicant) is proposing to modify the existing Encina Power Station (EPS) by replacing three of five existing boilers (Units 1, 2, and 3) at the facility with a net 540 MW (gross 558 MW) natural gas-fired combined cycle power plant facility called the Carlsbad Energy Center Project (CECP). Carlsbad Energy Center LLC and EPS are both indirect wholly owned subsidiaries of NRG Energy, Inc. The CECP will be located at the eastern end of the property site for the EPS in the city of Carlsbad, San Diego County, California.

The EPS currently has a total of five (5) natural gas-fired boilers (i.e., Units 1, 2, 3, 4, and 5), which are allowed to use No. 6 fuel oil during curtailments, and three fuel oil storage tanks. The CECP will consist of two rapid startup natural gas-fired combustion turbine generators (CTGs) and a 246-horsepower diesel emergency fire-pump engine. The two new CTG units will be designated Units 6 and 7, and will be located at the same location as the fuel oil tanks, which will also be removed. Since the EPS is an existing major source, and the CECP is a physical change to the facility, the Applicant must show whether the net emission increases for pollutants regulated under the Prevention of Significant Deterioration (PSD) permit program will result in a major modification that is subject to PSD major modification permit requirements.

On September 14, 2007, the Applicant filed an application for certification (AFC) with the California Energy Center (CEC) to obtain a license from the state agency. The AFC contained a PSD analysis that evaluated whether the change resulted in a major modification. The emissions estimates were based on the increase in potential emissions from the proposed CECP and the decrease in actual emissions from removing Units 1, 2, and 3.

For electric utility steam generating units (EUSGU), such as the units at the EPS, the PSD calculation methodology allows the use of any consecutive 24-month period during the 5-year period immediately preceding the date that construction of the project starts to determine baseline actual emissions. However, if the facility demonstrates that a 24-month period outside of the 5-year window is more representative of normal operations, EPA allows this alternative period to be used to determine baseline actual emissions. The AFC projected construction of the project to occur in the fourth quarter of 2008 and used calendar years 2002 and 2003 as the 24-month baseline period for nitrogen oxides (NOx), carbon monoxide (CO), and sulfur oxides (SOx), and calendar years 2004 and 2005 for volatile organic compounds (VOC) and particulate matter less than 10 microns (PM10). The Applicant's original analysis showed the project did not trigger a PSD major modification and a PSD permit was not required prior to proceeding with the CECP.[1]

[1] Based on EPA's informal review of the AFC in June 2008, the agency did not formally comment or object to this conclusion that the Project was not subject to PSD review.

In November 2008, the San Diego Air Pollution Control District (District) issued, for public comment and review, the preliminary determination of compliance (PDOC) for the CECP. The District issued the final determination of compliance (FDOC) on August 4, 2009. As of the date of this analysis, the CEC had not yet approved the AFC for CECP and the project's construction schedule has shifted to a later date which is dependent upon CEC license approval. Between the time of the issuance of the PDOC and FDOC, EPA received correspondence from community members and the City of Carlsbad, which had also received several calls from community members, requesting that the EPA require that the Applicant perform an updated analysis based on the new projected construction date since it had shifted by more than a year (from 2008 to 2010), which in turn may affect the baseline actual emission calculations.

On June 5, 2009, the Applicant submitted an analysis to EPA for determining whether PSD review applies to the CECP. The Applicant submitted additional information to EPA between the months of August 2009 and September 2010. Although the Applicant projected construction to start in early 2010, we will base our determination of PSD applicability on a conservative estimate of June 30, 2011, the expected actual construction date of the project. If the project has not begun construction by this time, a new analysis and determination will be required.

In its analysis, the Applicant requested use of an alternative 24-month period outside of the 5-year lookback period for calculating baseline actual emissions. Specifically, the Applicant requested to use a consecutive 24-month period of calendar years 2004 and 2005 because they are used in the District's PDOC and FDOC.[2] In 2009, the Applicant revised the emission estimates for EPS at the request of the District. EPA chose to use the 2009 revised emission estimates in its analysis, and thus the emissions estimates used in this analysis are different from those used in the Applicant's 2007 AFC.

II. Analysis

The EPS is an existing major source, as defined in 40 CFR 52.21(b)(1), since the facility is one of the 28 source categories, and emits or has the potential to emit (PTE) pollutants regulated under the PSD program at levels greater than or equal to 100 tons per year (tpy). Therefore, any modification (i.e., physical change or change in the method of operation) at the facility must be evaluated to determine whether the net emission increase of any PSD pollutant[3] will result in a major modification that is subject to PSD major modification permit requirements.

The PSD regulations at 40 CFR 52.21(a)(2)(iv) and 40 CFR 52.21(b)(3) contain the calculation methodologies for determining whether a physical change or change in the method of operation at an existing major source is subject to PSD review. A project is a major modification if it results in both a "significant emissions increase" and "a significant net emissions increase" of any PSD pollutant.

[2] See page 3 of the June 5, 2009 letter from George L. Piantka (NRG Energy) to Gerardo Rios (EPA Region 9) regarding "Subject: PSD Non-Applicability Determination Request for the Carlsbad Energy Center Power Project".
[3] "PSD pollutant" refers to "regulated NSR pollutant" as defined in 40 CFR 52.21(b)(50).

II.1 *Significant Emissions Increase (Step 1)*

The first step in determining whether a project results in a major modification is to determine whether the project will result in a significant emissions increase. (See 40 CFR 52.21(a)(2)(iv)(b).) The procedure for calculating (before beginning actual construction) whether a significant emissions increase will occur depends on whether the units being modified are new or existing emissions units.

The CECP involves installation of new CTGs and the removal of three existing boilers. Step 1 only considers emission increases from these units, and emission increases will occur only as a result of the new CTGs. For the new emissions units, a significant emissions increase of a PSD pollutant is determined by the difference between the potential-to-emit (PTE)[4] for each new emissions unit and the "baseline actual emissions"[5] for these units. Since these are new units, the baseline actual emissions for the units are zero.[6]

The emission increases expected from the new units are shown below in Table 1. The table shows that the proposed project results in a significant emission increase for NOx, CO, and particulates since the emissions of these pollutants exceed the applicable PSD significant levels. (See 40 CFR 52.21(b)(23).)

Table 1 - Emission Increases from New Units (Construction of CECP)

	NOx (tpy)	**CO (tpy)**	**VOC (tpy)**	**PM_{10}[7] (tpy)**	**SOx (tpy)**
PTE	72.8	339.9	23.7	39	5.6
Baseline Actual Emissions	0	0	0	0	0
Emission Increase	72.8	339.9	23.7	39	5.6
PSD Significant Level (40 CFR 52.21(b)(23))	40	100	40	15	40
Significant Emission Increase?	**Yes**	**Yes**	**No**	**Yes**	**No**

II.2 *Significant Net Emissions Increase (Step 2)*

The second step in determining whether a project results in a major modification is to determine whether the project will also result in a significant net emissions increase. (See 40 CFR 52.21(a)(2)(iv)(b).) The procedure for calculating whether a net emission increase will occur is in 40 CFR 52.21(b)(3). Generally, a net emissions increase occurs for a PSD pollutant when the sum of the emissions increases from a modification (Step 1), and any contemporaneous increases and decreases in actual emissions at the stationary source exceed zero. For PSD, a *significant* net emissions increase occurs when the net emissions increase exceeds the PSD significant levels.

[4] PTE is defined in 40 CFR 52.21(b)(4) and refers to the maximum capacity that a stationary source can emit a pollutant under its physical and operational design, or a practically enforceable emission limitation.
[5] The term "baseline actual emissions" is defined in 40 CFR 52.21(b)(48).
[6] See 40 CFR 52.21(b)(48)(iii).
[7] According to pages 6-7 of the FDOC issued by the District for the proposed CECP, all particulate matter (PM) is emitted as particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Thus, emissions of PM, PM_{10} and $PM_{2.5}$ are equivalent for the proposed CECP. The PSD significant level for $PM_{2.5}$ is 10 tpy. Therefore, the project is also significant for $PM_{2.5}$.

An increase or decrease in actual emissions is contemporaneous only if it occurs between the date five (5) years before construction of the modification and the date that the increase from the particular change occurs.[8] The new CTG units will replace existing Units 1, 2, and 3. The removal of these emission units will result in contemporaneous decreases. Permit conditions 81 and 84 require the emission units to be shut down by the end of the shakedown period for the CTGs, making the contemporaneous decreases enforceable. According to the District, no construction permits (ATCs) were issued to the EPS since 2002. Therefore, there are no other contemporaneous increases or decreases other than the contemporaneous decreases resulting from the shutdown of Units 1, 2, and 3.

Contemporaneous increases and decreases are calculated using the procedure in 40 CFR 52.21(b)(48), except that 40 CFR 52.21 (b)(48)(i)(c) and (b)(48)(ii)(d) do not apply, for determining baseline actual emissions. Baseline actual emissions for an EUSGU, such as the EPS, is the average annual rate of actual emissions during any consecutive 24-month period within the 5-year period immediately preceding project construction. In its June 2009 analysis submitted to EPA, the Applicant stated that it expects to begin construction of the project in 2010, pending issuance of the CEC license.[9] If the Applicant begins construction in 2010, the 5-year lookback period would be 2006 to 2010.

However, the Applicant believed that the period from 2006 onwards (i.e., until 2010) is not representative of normal source operation and has requested to use a different period for determining baseline actual emissions for the existing boilers that will be removed.[10] EPA allows the use of a different consecutive 24-month period if such period is determined to be more representative of normal source operation.[11]

As with most power plants, normal operation for EPS's Units 1, 2, and 3 is directly responding to demand for electricity. Operation is dependent on several factors. For instance, operations at EPS are influenced by the California Independent System Operator (ISO), which is responsible for dispatching power plant units to meet electric demand within an applicable service area, such as San Diego County. ISO dispatches power from newer, more efficient power plants prior to dispatching power from older units, such as the units at EPS. Therefore, older power plants will be dispatched even less often when new power plants come online in the service area. Electricity consumption and demand also affects operation.

There are a number of factors that can be used as indicators of normal operation at a power plant, including fuel usage. EPA examined annual historical fuel usage (i.e., natural gas consumption) for Units 1, 2 and 3 for the period of 1997 to 2009 provided by the Applicant.[12] (See Attachments A and B.) Based on this data, EPA determined that fuel usage for each unit has followed a cyclic nature resulting in several highs and lows between 1997 and 2006. This

[8] If the Applicant submitted an additional application prior to the start of construction for this project, then that application would have to consider the increases and decreases from this project.
[9] As of the date of this letter, the CEC has not approved license for this project.
[10] See page 3 of the June 5, 2009 letter from George L. Piantka (NRG Energy) to Gerardo Rios (EPA Region 9) regarding "Subject: PSD Non-Applicability Determination Request for the Carlsbad Energy Center Power Project".
[11] See 40 CFR 52.21(b)(48)(i).
[12] Data for 2010 was not yet available.

cyclic nature continued to occur even with the installation and operation of newer power plants in the San Diego County area. For example, the Wildflower, Escondido, and Border power plants came online in 2001, and the Palomar Power Plant came online in 2006, and the data suggests that the operation of these new power plants may have caused the EPS units to be dispatched less frequently by ISO. Thus, the years following 2001 and 2006 saw a drop in fuel usage.

However, fuel usage and, hence, the operation of the boilers plunged significantly in the years following 2006, dropping to its lowest levels in the 12 years of data examined. Fuel usage did not follow the same cyclic nature of highs and lows compared to previous years. The fuel usage data also indicates that the plant may have been dispatched even less in 2010 than previous years because the Otay Mesa Power Plant went online in 2009.[13] Therefore, EPA believes the period after 2006 is not representative of normal source operation for Units 1, 2 and 3 since normal operation would not occur at such significantly reduced capacity for such an extended period of time.

EPA examined monthly historical fuel data for Units 1, 2, and 3 to determine the most recent 24-month period prior to December 2006 that was more representative of normal source operation. (See Attachments C and D.) EPA determined that the 24-month period between May 2003 and April 2005 is the most recent period that is most representative of normal operation since this is the period before fuel use begins to decrease significantly at the EPS and where there were less periods when there was no fuel usage.[14] Thus, the emissions of NOx, CO, and particulates were calculated based on this period.

Table 2 summarizes the emission increases and contemporaneous emission increases and decreases for the proposed project. Based on this information, EPA has determined that the project will not result in a significant net emissions increase. As shown in Table 2, the proposed CECP will not result in a significant net emission increase.

Table 2 - Net Emission Increases

	NOx (tpy)	**CO (tpy)**	**PM10[15] (tpy)**
Significant Emission Increases from CECP	72.8	339.9	39.0
Contemporaneous Increases at EPS	0	0	0
Contemporaneous Decreases at EPS	-41.6	-289.0	-41.7
Net Emission Increase	39.2	50.9	-2.7
Significant Level (40 CFR 52.21(b)(23))	40	100	15
Significant Net Emission Increase?	**No**	**No**	**No**

[13] The Otay Mesa Power Plant came online in October 2009. See http://www.energy.ca.gov/sitingcases/all_projects.html.
[14] See monthly emissions data for Units 1, 2, and 3 provided in a June 11, 2010 e-mail from Tom Andrews (Sierra Research) to Shaheerah Kelly (EPA).
[15] According to Table 5a of the FDOC issued by the District, emissions of PM2.5, PM10, and PM from the Encina Power Station are very close and do not vary significantly (i.e., less than 1 tpy difference). Thus, the net emission increase for PM2.5, PM10, and PM are less than the PSD significant levels of 10 tpy, 15 tpy, and 25 tpy, respectively. Therefore, PSD permit requirements do not apply for these pollutants.

III. Conclusion

As explained above, the CECP will result in a significant emissions increase for NOx, CO, and particulates. However, the project will not cause or result in a significant net emissions increase for any pollutant. Therefore, the CECP will not result in a major modification and is not subject to PSD permit requirements.

ATTACHMENT A

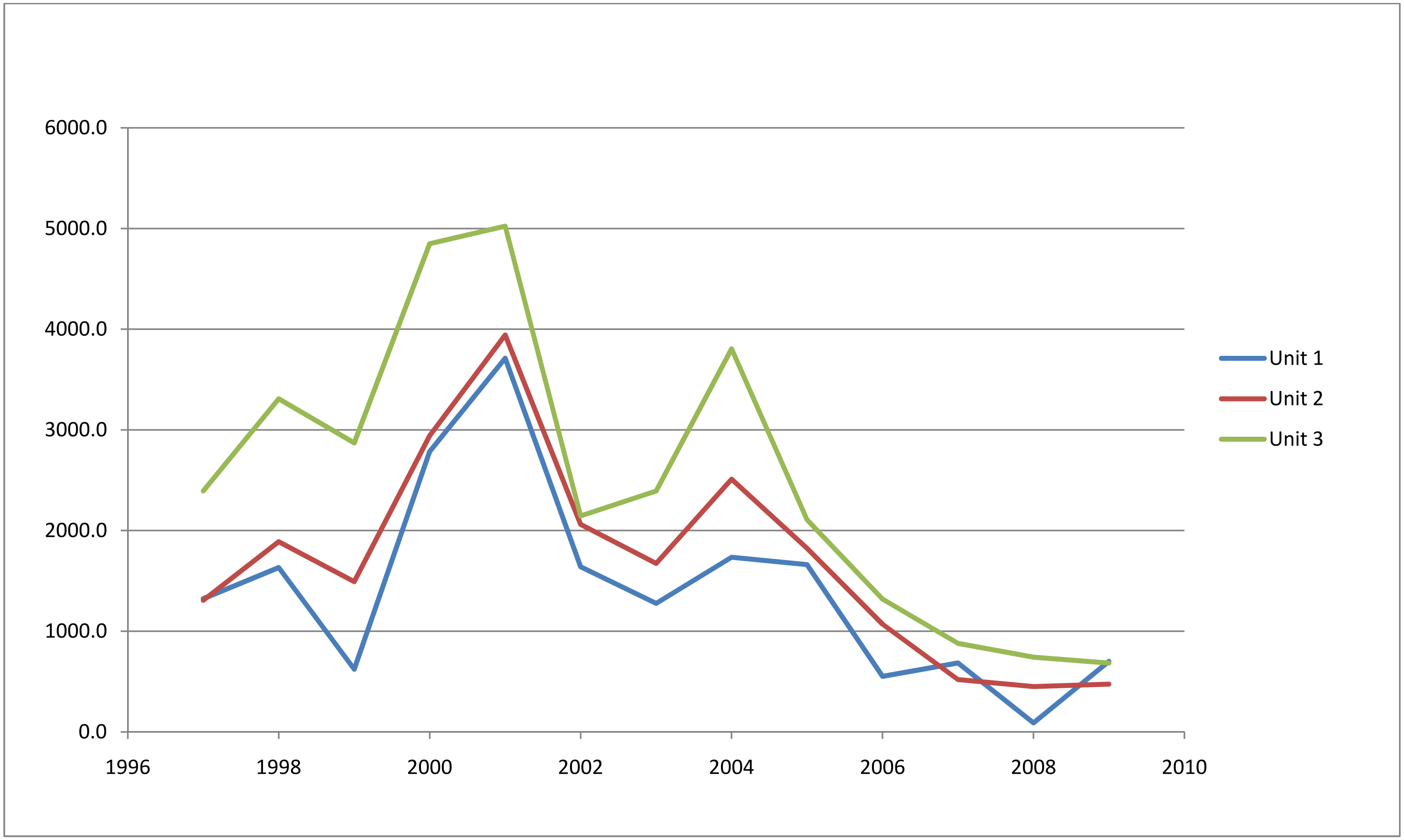
Annual Fuel Usage for the Encina Power Station Units 1-3

Natural Gas (MMscf/year)													
Emission Unit	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Unit 1	1,323.4	1,632.2	622.7	2,784.9	3,712.2	1,640.0	1,275.9	1,734.3	1,661.7	551.8	685.0	89.0	701.0
Unit 2	1,306.5	1,890.0	1,492.3	2,941.6	3,941.9	2,060.8	1,673.0	2,510.7	1,823.7	1,070.4	520.0	450.0	474.0
Unit 3	2,392.9	3,307.8	2,870.2	4,848.3	5,023.5	2,145.8	2,393.4	3,805.0	2,107.8	1,319.2	879.0	742.0	684.0
Total	25,823.0	31,528.0	31,758.4	35,627.9	41,945.9	26,239.6	26,713.4	34,354.0	21,136.2	15,131.4	8,677.0	12,095.0	1859.0

(Source: Emails dated March 12, 2010 and June 11, 2010 regarding “Encina Power Plant Fuel Use” from Tom W. Andrews (Sierra Research) to Shaheerah Kelly (U.S. EPA, Region 9))

ATTACHMENT B

Annual Fuel Usage (MMscf)
between 1997 and 2009 for Units 1-3



ATTACHMENT C

Monthly Fuel Usage (MMscf) between 2002 and 2009 for Units 1-3

Month	Unit 1							
	2002	2003	2004	2005	2006	2007	2008	2009
January	185.94	105.32	76.47	54.43	145.81	4.56	0.00	0.00
February	302.35	38.71	301.27	143.67	35.54	5.79	0.00	0.00
March	203.88	0.00	173.11	263.84	20.07	0.00	0.00	0.00
April	37.21	97.31	50.24	391.17	92.57	17.41	12.61	53.61
May	0.00	302.10	122.71	52.40	0.00	36.39	0.00	58.91
June	76.37	307.26	109.22	113.60	39.60	0.00	0.00	5.46
July	277.43	91.36	95.71	96.82	173.60	20.01	12.50	148.70
August	128.24	30.78	91.58	164.18	8.03	61.80	0.00	155.76
September	125.73	0.00	258.70	99.81	36.53	49.21	0.00	200.79
October	86.80	61.68	168.62	26.96	0.00	149.65	41.50	77.70
November	42.92	10.03	276.41	228.13	0.00	187.90	0.00	0.00
December	173.13	231.39	10.20	26.68	0.00	152.32	22.00	0.00
Total	1640.00	1275.94	1734.26	1661.66	551.76	685.00	89.00	701.00

(Source: Email dated June 11, 2010 regarding "Encina Monthly Emissions" from Tom W. Andrews (Sierra Research) to Shaheerah Kelly (U.S. EPA, Region 9))

Month	Unit 2							
	2002	2003	2004	2005	2006	2007	2008	2009
January	137.00	19.78	116.03	0.00	0.00	15.33	0.00	0.00
February	293.80	0.00	371.82	153.90	249.85	0.01	0.00	0.00
March	110.21	74.82	513.67	340.87	285.07	0.00	0.00	0.00
April	38.04	326.89	187.71	479.03	161.38	15.16	0.40	108.31
May	84.65	304.03	167.81	25.55	0.00	28.27	0.00	52.55
June	79.43	54.28	69.54	168.91	86.76	0.00	0.00	5.31
July	314.62	101.69	171.57	194.71	217.95	16.40	14.69	51.37
August	279.09	274.92	123.00	102.90	14.35	81.63	0.00	95.00
September	253.44	90.04	182.12	36.69	13.91	36.99	73.55	132.96
October	95.35	186.91	271.72	46.52	34.72	168.35	79.49	28.74
November	92.77	30.54	258.85	263.24	0.00	143.97	100.55	0.00
December	282.40	209.11	76.84	11.41	6.39	13.94	181.69	0.00
Total	2060.80	1673.01	2510.69	1823.74	1070.37	520.00	450.00	474.00

(Source: Email dated June 11, 2010 regarding "Encina Monthly Emissions" from Tom W. Andrews (Sierra Research) to Shaheerah Kelly (U.S. EPA, Region 9))

Month	Unit 3							
	2002	2003	2004	2005	2006	2007	2008	2009
January	19.83	298.91	228.87	197.18	0.00	0.00	205.79	0.00
February	333.29	249.42	422.32	234.71	240.60	13.36	0.29	11.54
March	208.12	11.52	426.09	308.40	365.75	0.03	0.00	59.39
April	70.75	52.05	134.64	259.73	218.69	17.00	20.50	176.22
May	24.90	247.15	272.34	0.00	0.00	27.36	61.48	89.47
June	186.33	31.92	79.09	171.61	90.29	0.00	0.00	4.43
July	428.34	197.31	254.07	174.92	239.74	36.93	11.90	83.31
August	377.73	312.14	189.52	104.83	78.68	124.19	14.65	57.51
September	367.98	404.11	412.54	86.52	7.70	97.96	48.78	140.01
October	107.77	125.29	492.95	180.65	71.50	187.06	92.33	62.50
November	0.00	180.00	482.33	300.26	0.00	187.79	51.52	0.00
December	20.76	283.62	410.28	88.95	6.28	187.19	234.56	0.00
Total	2145.81	2393.43	3805.04	2107.76	1319.23	879.00	742.00	684.00

(Source: Email dated June 11, 2010 regarding "Encina Monthly Emissions" from Tom W. Andrews (Sierra Research) to Shaheerah Kelly (U.S. EPA, Region 9))

ATTACHMENT D

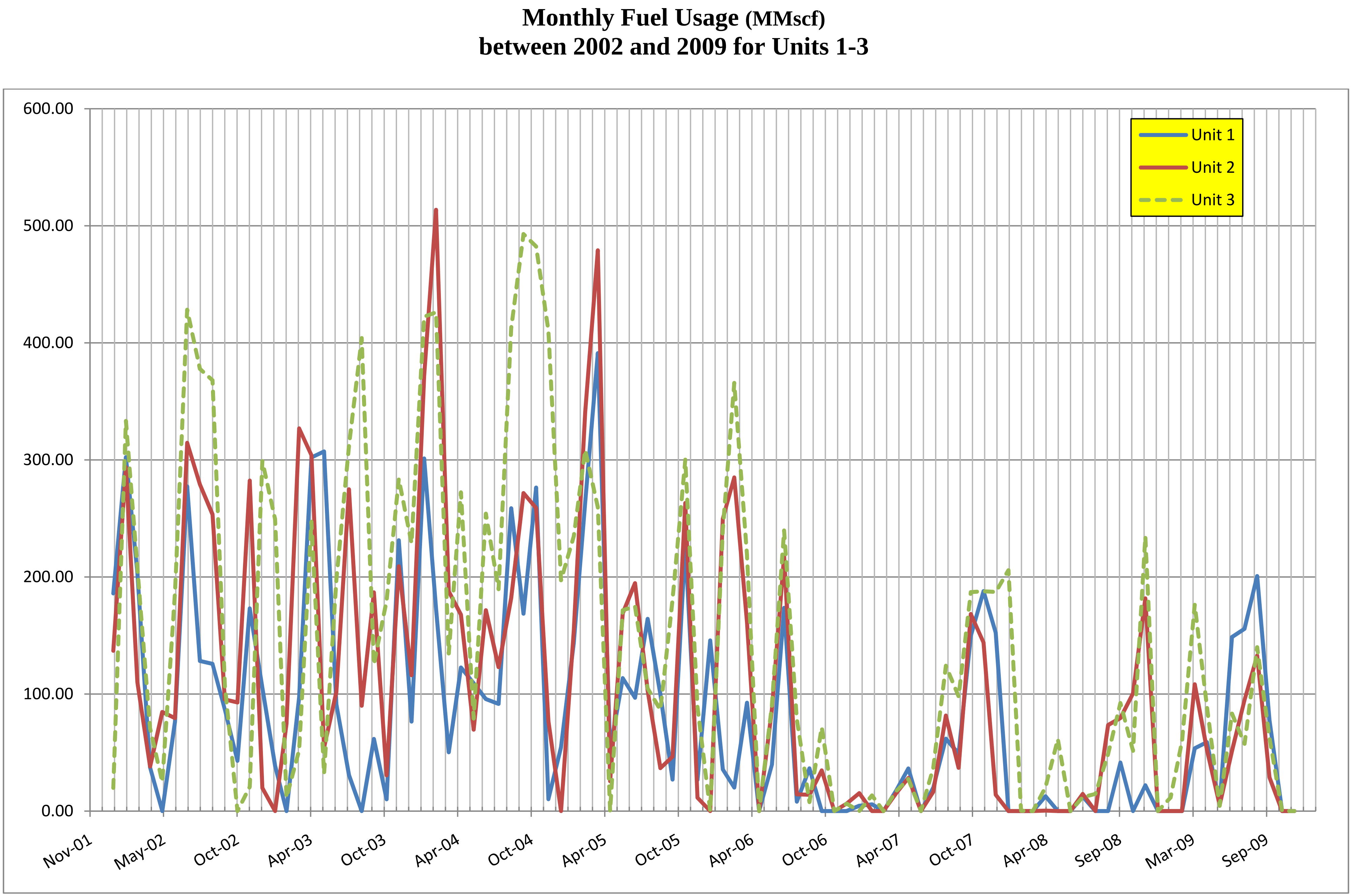


EXHIBIT 457

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

July 18, 2011

Mr. George L. Piantka, P.E.
NRG Energy Inc. – West Region
5790 Fleet Street, Suite 200
Carlsbad, California 92008

Subject: New PSD Applicability Determination Analysis for the Carlsbad Energy Center Power Project

Dear Mr. Piantka:

This letter is to inform you that the United Stated Environmental Protection Agency (EPA) is withdrawing as moot the Prevention of Significant Deterioration (PSD) applicability determination for the Carlsbad Energy Center Project (CECP) previously issued on October 13, 2010 and January 11, 2011. The analysis contained in that applicability determination was based on a projected actual construction date of June 30, 2011, and clearly stated that if "the project has not begun construction by this time, a new [applicability] analysis and determination will be required." *See* PSD Applicability Analysis for the Carlsbad Energy Center Project at 2. In this case, the California Energy Commission did not issue the necessary approvals that would allow NRG to start construction by June 30, 2011, so NRG did not have authority to begin actual construction on the CECP by that date.

Accordingly, the prior applicability determination is no longer valid. In withdrawing this PSD applicability determination as moot, we also note that we have concluded that the analysis contained in it was made in error. As such, neither the overall determination nor the rationale and analysis contained therein can be relied upon to undertake actions related to the CECP or any other facility. In revoking this particular analysis, EPA emphasizes that there still may be specific permitting circumstances in which EPA may use the discretion provided by 40 CFR §52.21 (b)(48)(i) to select a different period for determining the baseline actual emissions, but the use of such discretion will be based on the particular facts of the permitting situation under consideration.[1]

[1] EPA also notes that the discretion to consider a different period for calculating baseline actual emissions for determining PSD applicability is limited to applicability determinations performed by the Agency and other approved permitting authorities and may not be invoked independently by emission sources and/or permit applicants. *See* 40 CFR §52.21 (b)(48)(i) (limiting use of a different time period to the *Administrator's* determination "that it is more representative of normal source operation"); 40 CFR §51.166 (b)(48)(i) (providing same discretion to approved permitting authorities).

EPA is committed to working with NRG to complete a new applicability determination for the CECP. If such a determination is requested, please be aware that EPA will also consider PSD applicability for greenhouse gases that might be emitted from the project. *See* 40 CFR §52.21 (b)(48)(v)(b); 75 Fed. Reg. 31514, 31527 (June 3, 2010). If you have any questions, please contact Shaheerah Kelly of the Air Permits Office at (415) 947-4156.

Sincerely,

Deborah Jordan
Director, Air Division

cc: Robert Kard, San Diego Air Pollution Control District
Steven Moore, San Diego Air Pollution Control District
Tom Andrews, Sierra Research
Mike Monasmith, California Energy Commission
Will Walters, Aspen Environmental Group
Joe Garuba, City of Carlsbad

EXHIBIT 458

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

MAR - 4 2011

Ref: 8P-AR

Cheryl Heying, Director
Division of Air Quality
Utah Dept. of Environmental Quality
P.O. Box 144820
Salt Lake City, UT 84114-4820

Re: Comments on Intent-to-Approve for Pacificorp Lake Side Power Plant, Block #2

Dear Cheryl:

The purpose of this letter is to submit EPA's comments on the draft pre-construction permit titled an Intent-to-Approve (ITA), DAQE-IN0130310010-11, for the above-named electric utility combustion turbine project. Although we have a number of comments on this permit action, we expect that many of them can be readily addressed. Our comments are enclosed along with our recommendations on how to address them. We provide these comments to help ensure that the project meets all federal requirements, that the permit provides all necessary information so that it is readily accessible to the public, and that the record provides adequate support for the permit decision.

Thank you for the opportunity to comment. We would appreciate a written response. If you have any questions, please feel free to contact me at 303-312-6223, or your staff may contact Mike Owens at 303-312-6440.

Sincerely,

Deborah Lebow Aal
Acting Director
Air Program

Enclosures:
1. EPA comments on Lake Side Block 2 permit action
2. EPA comments on December 9, 2004 on Lake Side Block 1 permit action
3. Federal PSD Permit dated March 11, 2010 by Region 9 for Victorville 2 project
4. Siemens technical paper, "SGT-5000F (W501F) Engine Enhancements to Improve Operational Flexibility"

cc: Regg Olsen (Utah DAQ)
Marty Gray (Utah DAQ)
John Jenks (Utah DAQ)

Enclosure

EPA Comments on Proposed PSD and Major NAA NSR Permit For Construction of Pacificorp Lake Side Block #2 Project

Introduction:

This project is described in the Intent-to-Approve (ITA) as a nominal 629-megawatt electric utility generating block, consisting of two natural gas fired combustion turbines (CTs) with heat recovery steam generators (HRSGs), auxiliary boiler, emergency generator and cooling tower. (The project is described, however, in the September 2008 permit application as a nominal 565-megawatt generating block.)

Each CT/HRSG will be equipped with low-NOx combustors and selective catalytic reduction (SCR) for nitrogen oxide (NO_x) emission control, as well as oxidation catalyst for carbon monoxide (CO) and volatile organic compounds (VOC) emissions control. The Auxiliary Boiler will be equipped with low-NOx burners for NOx emission control. The CT/HRSGs and Auxiliary Boiler will be restricted to natural gas as fuel (via permit condition II.B.3.a). The project will be located in the Utah County PM_{10} nonattainment area, just north of the old Geneva Steel mill site at Vineyard.

The project will be a Prevention of Significant Deterioration (PSD) major modification to an existing PSD-permitted and major nonattainment New Source Review (NSR) permitted major source (Lake Side Block #1). The existing source is an electric utility power plant consisting of two natural gas fired CT/HRSGs, an auxiliary boiler, and associated equipment.

The project will have potential emission increases above PSD significance thresholds in tons per year (tpy) for NO_x (at 143 tpy; significance threshold is 40 tpy), CO (at 588 tpy; significance threshold is 100 tpy) and VOC (at 98 tpy; significance threshold is 40 tpy). The project is therefore a PSD major modification for each of these three pollutants and is subject to PSD Best Available Control Technology (BACT) for each of these pollutants.

The existing Block #1 is a major source of greenhouse gases (GHGs), at about 1.8 million tpy of potential CO_2-equivalent (CO2e) emissions. Potential emission increases of GHGs, due to the addition of Block #2, are about 1.8 million tpy, which is above the 75,000 tpy CO2e regulated NSR pollutant threshold for GHGs, as defined in the PSD and Title V Greenhouse Gas Tailoring Rule (75 FR 31514, June 3, 2010). Potential emission increases are also above the zero tpy significance threshold for mass emissions of GHGs. The project is therefore a PSD major modification for GHGs and is subject to PSD BACT for GHGs.

The project will be located in a nonattainment area (NAA) for PM_{10} and $PM_{2.5}$, with potential emission increases above significance thresholds for major NAA permitting for PM_{10} and $PM_{2.5}$ (at 118 tpy for both; significance threshold for PM_{10} is 15 tpy; significance threshold for $PM_{2.5}$ is 10 tpy of direct $PM_{2.5}$ emissions. In accordance with the State's approved State Implementation Plan (SIP) for PM_{10} and 40 CFR part 51 Appendix S for $PM_{2.5}$, the project will be subject to Lowest Achievable Emission Rate (LAER) for PM_{10} and $PM_{2.5}$. In addition, the

State's Source Plan Review (SPR) indicates that since the modification is major for NO_x, the NO_x emissions are treated as though they are PM_{10} emissions. Therefore, according to the State's analysis, LAER also applies to NO_x.

Our comments are based on review of the following documents:

July 21, 2008	Modeling protocol
Sept. 30, 2008	Permit application
Nov. 10, 2008	Application addendum
Jan. 29, 2009	Modeling addendum
Apr. 22, 2009	Modeling memorandum
Aug. 3, 2010	Application addendum
Aug. 25, 2010	Application addendum
Nov. 16, 2010	Modeling memorandum
Jan. 6, 2011	Modeling memorandum
Jan. 10, 2011	Source Plan Review (SPR)
Jan. 19, 2011	Legal Notice of Intent to Approve
Jan. 19, 2011	Intent to Approve (ITA)

BACT-specific comments:

1. Inadequate explanation in the State's SPR on the process for determining BACT. As far back as 1990, EPA has itself used, and has recommended to states, a five-step top-down process for making PSD BACT determinations, to ensure compliance with the BACT criteria in the Clean Air Act and applicable regulations. EPA's recently issued PSD and Title V Permitting Guidance for GHGs (dated November 2010) provides a comprehensive description of this process, not just for GHGs, but for any pollutant at any type of emitting unit. (See pages 18 through 47 of the Guidance.) The Guidance is available at:

http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf.

The first four steps described in the Guidance involve a determination of the appropriate control technology as BACT, while the fifth step establishes a BACT emissions limit based on application of the selected control technology. As explained in the Guidance, EPA has not established the top-down BACT process as a binding requirement through rule, so permitting authorities that implement an EPA-approved PSD permitting program, such as the Utah Division of Air Quality, may use another process for determining BACT in permits they issue. However, those permitting authorities must show that the BACT determination process, as well as each BACT selection made through that process, complies with the relevant statutory and regulatory requirements for BACT (such as consideration of energy, environmental, and economic impacts). (See page 20 of the Guidance.)

The SPR does not mention, or appear to apply, the top-down BACT process, nor does it provide an adequate explanation of any other process that might have been used for the proposed

BACT determination. Accordingly, it is not clear whether the State might have omitted some of the statutory and regulatory requirements in determining the appropriate control technologies for this source.

We recognize that under existing BACT guidance, if only one control option is known to be available, or if more than one option is available, but the best-performing option is selected (which appears to be the case with the CT/HRSGs and Auxiliary Boiler), then the explanation of the process for determining the appropriate control technology need not be elaborate. Nevertheless, to adequately support the BACT determination for each pollutant at each emitting unit, the SPR should, at a minimum, clarify whether all available control options were considered, whether the option selected is the best-performing option that is known to be available and technically feasible, whether energy, environmental and economic impacts affected the selection of the control option, and if the best-performing option was not selected, provide an explanation and supporting basis for that selection.

2. Lack of permit emission limit(s) as PSD BACT for greenhouse gas. The ITA does not include a BACT emission limit for GHGs, nor is it apparent in the ITA that a design standard or other type of requirement is intended in lieu of a numerical emission limit. The SPR discusses GHG emissions and energy efficiency, concluding that the Lake Side Block 2 plant should be able to meet the California CO_2 emissions standard of 0.5 metric tons per net megawatt-hour for baseload power plants, but *does not propose* a numerical emission limit as GHG BACT. Instead, the SPR proposes (at page 21) an undefined design standard as BACT (i.e., use of "high efficiency" CT/HRSG unit). Please indicate in the SPR what is meant by "high efficiency." This proposal of an undefined design standard as BACT, rather than a numerical emission limit, does not satisfy the definition of BACT at 40 CFR 52.21(b)(12), incorporated into the State's SIP-approved rules at R307-101-2, and is not consistent with the Permitting Guidance for GHGs cited in our comment #1 above.

The definition of BACT at 40 CFR 52.21(b)(12), incorporated into the State's SIP-approved rules at R307-101-2, allows for the option of prescribing a design standard in lieu of an emission limitation as BACT, but only if "technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible." Similarly, the Permitting Guidance for GHGs (cited in our comment #1 above), at page 47, states a design standard may not be used as BACT in lieu of a numerical emissions limitation(s), unless there is a demonstration in the record that the criteria for applying such a standard are satisfied. No such demonstration has been presented in the permit record for the Lake Side Block 2 project, i.e., no reason presented as to why GHG BACT for this project should not be expressed as an emission limitation.

The Permitting Guidance for GHGs further states, at page 46, that "EPA encourages permitting authorities to consider establishing an output-based BACT emission limit, or a combination of output- and input-based limits, wherever feasible and appropriate to ensure that BACT is complied with at all levels of operation." We note that Pacificorp's August 25, 2010 application addendum (at page 5) projects a net heat rate for Lake Side Block 2 plant of 6918 Btu/kWh HHV (Btu per kilowatt-hour produced, on a high heating value basis). Pacificorp states that the projected net heat rate of a similar project, the Russell City Energy Center (RCEC), is 6852 Btu/kWh, "presumably on a HHV basis." Thus, Pacificorp states, the efficiency of the Lake Side Block 2 plant is similar to the energy efficiency of the RCEC project.

Although the net heat rate figures for RCEC and the Lake Side Block 2 plant are indeed similar, the figures of 6918 Btu/kWh and 6852 Btu/kWh suggest to us that the energy efficiency of the Lake Side project will be slightly lower than RCEC.

To be consistent with the SIP definition of BACT and with the Permitting Guidance for GHGs, we recommend the State supplement its GHG BACT analysis in the SPR to explain why a lower energy efficiency than RCEC, on an output basis, could still satisfy BACT for Lake Side Block 2, how this level of efficiency compares to the California standard, and include an appropriate BACT limit in the Lake Side permit. The State may find it useful to examine the RCEC permit as an example of how to express GHG BACT in a permit (available on the Bay Area Air Quality Management District's website, at http://www.baaqmd.gov, or from Mr. Weyman Lee of the BAAQMD, 415-749-4796, Weyman@baaqmd.gov.)

Additionally, as indicated in our Introduction above, there are two varying figures cited in the permit record as the maximum generating capacity of Block #2 (565 MW and 629 MW). It is unclear whether the varying plant capacity is due to changes in the design of the HRSG after the permit application was submitted, or issues associated with the CTs as well. In either case, the plant generating capacity will affect the overall plant efficiency and any output-based numeric GHG BACT limits. We recommend the State clarify whether Block #2 will generate 565 or 629 MW, and which figure was used to calculate the efficiency quoted above of 6918 Btu/kWh.

3. Lack of permit emission limits and adequate explanation for PSD BACT for VOCs. As explained in our Introduction above, this project is subject to BACT for VOC. The review of BACT in the SPR (at page 6) concludes that BACT for VOC, for each CT/HRSG, has been determined to be good combustor design and CO/VOC oxidation catalyst. Page 3 of the SPR proposes a VOC BACT emission limit at each Turbine/HRSG stack of 3.0 parts per million by volume, dry (ppmvd) at 15% oxygen, on a 3-hour average. The SPR states that this limit is listed in the ITA. The ITA does not, however, include this proposed emission limit. This appears to be an inadvertent omission. We recommend this be corrected.

We also find the SPR does not explain why the specific numerical limit of 3.0 ppmvd was determined to be BACT for VOC for the CT/HRSGs. Section 4.3.2 of Pacificorp's September 2008 permit application lists a range of BACT emission limits for VOC for recently permitted CT/HRSGs with duct firing, varying from 1.4 ppmvd to 6 ppmvd. Pacificorp notes that the VOC BACT emission limit for the CT/HRSGs at Lake Side Block 1 is 2.0 ppmvd, but proposes 3.0 ppmvd for Block 2, on the basis of 60% more duct firing than Block 1. We recommend an explanation be included in the permit record as to why 60% more duct firing would result in 50% higher VOC emissions.

Also missing from the SPR is an explanation as to why no PSD BACT emission limit for VOC is proposed for the Auxiliary Boiler. The PSD rules at 40 CFR 52.21(j)(3), incorporated by reference into the State's current PSD rules at R307-405-11, state that "A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit." This would include VOC for the Auxiliary Boiler.

R307-405-11 is not yet SIP-approved; however, the State's current *EPA-approved SIP rules*, at R307-1-3.1.8.A, require BACT for a broader range of permitting situations and emitting units than §52.21(j)(3), which would also include VOC for the Auxiliary Boiler. The SIP rules say the State shall issue an "Approval Order" (which is described in the SIP-approved rules at R307-1-3.1.1 as any pre-construction permit for a new or modified source, regardless of whether it is a major or minor NSR permit), if the State determines that the degree of emission control is at least BACT, except as otherwise provided in R307. So under the current SIP rules, as well as under the current State-effective PSD rules, the requirement for BACT for VOC includes the Auxiliary Boiler.

We note that while section 4.4.3 of Pacificorp's permit application *discusses* BACT for VOC for the auxiliary boiler, it does not *propose* a BACT emission limit. The State should either include a numerical VOC BACT emission limit for the Auxiliary Boiler in the Lake Side permit, with appropriate explanation for selection of the specific limit, or else provide a VOC limit based on a design or operational standard, with an adequate explanation why a VOC emission limit should not be required at the Auxiliary Boiler.

4. BACT during startup/shutdown:

A. Definition for end of startup in the ITA prevents application of BACT limits for indefinite periods of time. The ITA's definition for end of startup, at Condition II.B.3.f, prevents application of BACT limits associated with "steady state operation" for indefinite periods of time and therefore warrants revision. ITA Condition II.B.3.b states that the NO_x and CO BACT emission limits for the CT/HRSGs only apply under "steady state operation." Condition II.B.3.f states that:

> *"Steady state operation means all periods of combustion turbine operation, except for periods of startup and shutdown as defined below, and periods of transient load conditions as defined Condition II.B.3.e. Startup is defined as the period beginning with turbine initial firing until the unit meets the ppmvd emission limits in the first table of Condition II.B.3.b for steady state operation. Shutdown is defined as the period beginning with the initiation of turbine shutdown sequence and ending with the cessation of firing of the gas turbine engine."*

This permit language creates circular logic: Under Condition II.B.3.f, if a CT/HRSG starts up and is *never* able to meet its NO_x or CO BACT emission limits for steady state operation, the permittee could legitimately assert, under the terms of the permit, that the CT/HRSG remains in startup indefinitely, and is therefore not subject to the BACT limits for steady state operation.

We made this same comment on December 9, 2004, on permitting of Lake Side Block 1. We have included a copy of our prior comments as an enclosure. (See comment #7 in the enclosure.) The State's Response-to-Comments memo, dated August 14, 2006, acknowledged that such circular logic should be avoided in permit conditions. (See State's response #13.)

We note that the ITA contains no limit on the number of hours that the CT/HRSGs at Block 2 can remain in startup or shutdown mode, although the ITA does contain a limit of 613.5 hours per turbine per calendar year at Block 1. We also note that section 3 of Pacificorp's permit application addendum for Block 2, dated August 2, 2010, discusses startup/shutdown, but it does not propose a definition for startup or shutdown, nor any limits on duration of startup or shutdown.

Our most recent comments to the State, on appropriate permit conditions to address startup/shutdown for combustion turbine facilities, were on March 8, 2007, involving Pacificorp's Currant Creek facility. As an example or 'template' for the State to consider, we cited Region 9's Federal PSD permit, dated August 2005, for the San Joaquin Valley Energy Center, which limits the duration of individual startups to three hours.

Since 2005, Region 9 has issued several more Federal PSD permits for combustion turbine projects. As their most recent effort to 'fine-tune' permit conditions for startup/ shutdown, Region 9 has cited to us their PSD permit issued on March 11, 2010, for the Victorville 2 Hybrid Power Project, a 563 megawatt combined cycle power plant, consisting of two CT/HRSGs. A copy of that permit is enclosed. Permit condition IX.D.1 says:

> *Startup is defined as the period beginning with ignition and lasting until either the equipment complies with all operating permit limits for two consecutive 15-minute averaging periods or the maximum time allowed for the event after ignition, whichever occurs first.*

Additional language in Condition IX.D.1 distinguishes cold startups from warm and hot startups, defines shutdown, and imposes duration limits: 1.8 hrs per cold startup event, 1.3 hours per warm and hot startup, and 0.5 hours per shutdown event. These limits are based on the latest 'quick-start' technology. The permit condition also specifies monitoring and recordkeeping requirements for startup and shutdown events. We recommend the State consider Region 9's permit as an example of how to address startup/shutdown in permit conditions, and revise the definition of startup in the Lake Side Block 2 permit, to prevent BACT limits for steady state operation from being avoided for indefinite periods of time.

B. <u>Emission limits for BACT for startup/shutdown should be established using the same BACT determination steps as emission limits for BACT for steady-state operation; and the proposed limits for startup/shutdown appear to be too high to represent BACT</u>. ITA condition II.B.3.f specifies emission limits of 260 lb/hr for NO_x and 6000 lb/hr for CO, from both CT/HRSGs combined, applicable during startup or shutdown operation. These limits are separate from the NO_x and CO emission limits in condition II.B.3.b, which are the BACT limits applicable during steady state operation. There is no explanation in the SPR regarding the decision process or manner the State used to develop the proposed limits. Therefore, it is not clear how the proposed emission limits for startup and shutdown meet the definition of BACT. Section 3 of Pacificorp's permit application addendum, dated August 2, 2010, discusses startup/shutdown and proposes the limits of 260 lb/hr and 6000 lb/hr, but it is not clear from that discussion, or from the SPR, how the State went about establishing those limits and why those proposed limits represent BACT.

Pacificorp indicates that the proposed emission limits for startup limits for Block 2 were based on an analysis of actual operating data from Block 1 for the years 2008 and 2009 for both combustion turbines combined. It is not clear how a mass emission limit on both CTs combined (rather than a performance based limit based on total heat input to both CTs) could be indicative of the "maximum degree of reduction achievable" (part of the definition of BACT in SIP rules) for each individual CT. If a single CT is started up without the second CT, the actual mass emission rate would be half of the actual mass emission rate associated with the "lagging turbine" startup scenario of both turbines, described by Pacificorp on page 3-1 of the August 2, 2010 application addendum:

> *During a startup involving both CTGs, the startup of each CTG is staggered so one CTG reaches its steady-state emissions level before the second CTG. During the startup involving both CTGs, startup is assumed to have been achieved when the second (or lagging) CTG has achieved 50-60% of its full load output.*

Elsewhere in this section of the addendum, Pacificorp mentions "overlap" in the startups of two turbines. We understand this to mean that one turbine would not yet be finished with the startup sequence before the second turbine initiates its own startup sequence. This startup scenario was apparently relied on by the State for establishing the startup emission limits for NO_x and CO. This appears to be *only one possible* startup scenario, not the *only* startup scenario. If only one CT is started at a time (i.e., not the "staggered" or "overlap" startup described by Pacificorp), the proposed CO and NO_x mass emission limits would not be indicative of the actual startup scenario.

In other words, it is questionable whether the combined limit in the proposed permit can provide BACT levels of control, if only one turbine is in startup mode. Separate BACT limits should be proposed for each CT individually during startup, or an enforceable requirement should be included to assure that the staggered start of both turbines (described in the August 2, 2010 PacifiCorp application addendum) is followed for all startups, to ensure that the operational facts relied upon in setting the combined BACT limit are actually present during use of that limit.

Additionally, it appears that the CTs at Block 2 could comply with a much lower combined CO emission limit for startup than 6000 lb/hr. We have examined a technical paper available from the combustion turbine manufacturer (Siemens), regarding startup emissions of CO from the type of combustion turbine proposed for Lake Side Block #2. The paper is titled, "*SGT6-5000F (W501F) Engine Enhancements to Improve Operational Flexibility.*" We have enclosed a copy for your convenience. It is also available online at:

> http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/papers/Siemens_SGT6-5000F%20(W501F)%20Engine%20Enhancements%20to%20Improve%20Op.pdf

The technical paper explains that the latest generation SGT6-5000F Siemens CT has incorporated design changes to reduce CO emissions during low load and startup. The paper states, on page 8, that "**The CO reduction will reduce total CO mass emissions by 70% per startup-shutdown cycle**." This conclusion appears to be based on actual operating data.

The proposed CO BACT emissions limits in the State's ITA for startup were apparently based on current CTs at Block 1. Pacificorp's permit application addendum for the Block 2 project dated August 2, 2010 states, on page 3-4, that "... for proposing short-term emission limits for startup/shutdown, the actual continuous emissions monitoring CEMS emissions data profiles at Block 1 were reviewed." This basis for establishing startup BACT limits for Block 2 would not seem adequate, if the Block 1 CTs are not the latest generation 5000F CT, and therefore not directly comparable to the proposed CTs for Block 2, with regard to startup CO emissions.

If startup emissions of CO from the latest Siemens CT are indeed 70% lower than the previous generation, a more appropriate BACT limit might be in the range of 1800 lb/hr for both turbines combined, rather than ITA's proposed startup limit of 6000 lb/hr. An explanation should be provided in the permit record as to whether the proposed CTs for Block 2 are a later generation than the CTs for Block 1, and if so, whether a lower CO BACT limit during startup would be appropriate. Additionally, if BACT limits are to be included in the permit for startup/shutdown, the SPR should be revised to establish those limits in the same manner as for BACT limits for steady-state operation. See our related comment #1 above.

Distinction between BACT and LAER determination processes for NO_x:

5. Lack of distinction in SPR between BACT and LAER determination processes: As explained in our Introduction above, based on the State's analysis NO_x is the one pollutant to be emitted by this project that is subject to both a BACT determination and a LAER determination. The statutory and regulatory requirements for making BACT determinations (cited in our comment #1 above) are substantially different from the requirements in NAA NSR rules for making a LAER determination. The SPR does not describe how the State has met either set of requirements. The SPR simply lists the proposed NO_x emission limits at the Turbine/HRSG stacks and at the Auxiliary Boiler, indicates that the proposed limits are intended to serve as both BACT and LAER limits, and states that the proposed limits are the lowest found in review of recent permitting actions and the RBLC database. The SPR should provide at least a brief description of the processes the State has used to determine BACT and LAER (preferably using the processes cited in our related comments #1 and #7) and clarify how the proposed NO_x emission limits meet the regulatory criteria defining BACT and LAER.

LAER-specific comments:

6. Lack of a permit emission limit for LAER for $PM_{2.5}$. As stated in our Introduction above, the Block 2 project will be located in a $PM_{2.5}$ nonattainment area, and will have a potential emission increase above the significance threshold for major NAA permitting for $PM_{2.5}$. Therefore, the project will be a major modification for NAA permitting and will be subject to LAER for $PM_{2.5}$, under SIP rules at R307-403-3(3)(a). The SPR indicates, on page 6, that LAER for "$PM_{10}/PM_{2.5}$" at each CT/HRSG unit consists of use of pipeline quality natural gas, good combustor design, and an emission limit of 14 lb/hr with duct firing. The ITA includes this emission limit, but indicates it is only for "PM_{10}."

We note that section 2.3 of an August 3, 2010 addendum to Pacificorp's permit application, titled "LAER $PM_{2.5}$," proposes 15.5 lb/hr as a LAER emission limit for each CT/HRSG, so the applicant is clearly acknowledging that LAER applies for $PM_{2.5}$. To comply with the SIP rule requirement cited above for LAER for $PM_{2.5}$, the ITA should be corrected to indicate that the LAER emission limit of 14 lb/hr is for both PM_{10} and $PM_{2.5}$, or else the ITA should include a separate LAER emission limit for $PM_{2.5}$, with an explanation in the SPR as to how the separate limit was determined to be LAER. Alternatively, the state may use a surrogate approach for addressing $PM_{2.5}$, but such approach must be supported by a technical demonstration that the use of such surrogate is reasonable for this particular application.

To the extent the State intended to apply EPA's 2005 guidance regarding use of PM_{10} as surrogate for $PM_{2.5}$ in nonattainment NSR, the State should explain in the record and take note of clarifications that EPA has issued recently on the application of the PM_{10} surrogate policy in the PSD context. The EPA Environmental Appeals Board recently summarized EPA's views on application of the surrogate policy in PSD as follows:

> [In] order to justify the use of a surrogacy analysis, permit applicants and issuers must demonstrate that PM_{10} is a reasonable surrogate for $PM_{2.5}$. That demonstration must address, among other things, the differences between PM_{10} and $PM_{2.5}$ and must include a detailed and well-supported analysis of why PM_{10} is nevertheless and adequate surrogate.

In re: Vulcan Construction Materials, LP, PSD Appeal No. 10-11, Slip. Op. at 14 (March 1, 2011); *See also, In re Louisville Gas and Electric Co.*, Petition No. IV-2008-3 (Adm'r August 12, 2009). This reasoning **applies equally to LAER determinations** and should be considered by the State, if the State seeks to use a limitation on PM_{10} alone to establish compliance with the LAER requirement for $PM_{2.5}$.

7. Inadequate explanation for LAER determination for $PM_{10}/PM_{2.5}$. As indicated in our comment #6 above, the ITA includes a LAER emission limit for PM_{10} of 14 lb/hr with duct firing, at each CT/HRSG unit. The SPR indicates this emission limit is based on use of pipeline quality natural gas and good combustor design. The only explanation in the SPR on how this specific numerical emission limit was determined to be LAER is a statement that recent permitting actions and the EPA RBLC database were reviewed, and that this review showed the

proposed emission limit is the "lowest emission rate" for that pollutant. (We presume this means the lowest emission rate found in the RBLC database.) Section 2.3 of the August 3, 2010 application addendum, mentioned in comment #6 above, provides no additional useful information on how LAER was determined.

LAER is defined in the State's SIP-approved rules at R307-403-1(1) as the rate of emissions which reflects: (a) the most stringent emission limitation which is contained in the implementation plan of any state for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (b) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent. Although section 4.2 of Pacificorp's permit application acknowledges that these criteria must be satisfied for LAER, the SPR does not mention these criteria, nor explain if these criteria were met in making the LAER determination for PM10/PM2.5.

We submitted this same comment on December 9, 2004, for the Lake Side Block 1 project. We stated there was not an adequate explanation in the SPR of how the LAER emission limit for PM10 for the combustion turbines was determined. In its August 14, 2006 response to our comment, the State agreed with us and provided the following explanation:

> *At present there are no combustion turbine sources included in the Utah SIP that are comparable with the proposed LSPP [Lake Side Power Plant] source. UDAQ is not aware of a similar type or size of source being listed in the SIP for any other state with lower emission values (please see UDAQ's response to comment #10). As discussed in UDAQ's response to comment #10 above, it is a fallacy to compare limits achievable by one type or size of combustion turbine with those of a different type or size. Physical design characteristics, efficiency ratings, and other similar factors can all contribute to a different source having different emission limitations. That being said, the Summit Vineyard source has tighter emission values than the few other combustion turbine source listed in the Utah SIP.*
>
> *The Division also agrees that no discussion on control costs should be included in an LAER analysis. This discussion led to the erroneous removal of emission limits on the auxiliary boiler. These limits have been replaced in the final AO (see UDAQ's response to comment #6 above).*

The SPR for the Block 2 project should similarly include an explanation how the LAER emission limit for PM_{10} and $PM_{2.5}$ for the combustion turbines were determined, updated as necessary to reflect the latest information available.

8. <u>Inadequate explanation for LAER determination for NO_x</u>. This comment is similar to our comment #7 above. The ITA includes a NO_x LAER emission limit of 2.0 ppmvd at 15% oxygen, on a 3-hour average, at each CT/HRSG unit. The SPR indicates this emission limit is based on inherent low-NO_x combustor design and SCR with ammonia injection. The only explanation in the SPR on how this specific numerical emission limit was determined to be LAER is a

statement on page 6 that recent permitting actions and the RBLC database were reviewed, and that this review showed the proposed emission limit is the "lowest emission rate" for that pollutant. Similarly, for the Auxiliary Boiler, the only explanation in the SPR on how the specific numerical emission limit of 0.017 lb/MMBtu was determined to be LAER is a statement on page 7 that a recent review of similarly sized boilers at similar installations shows that this is the lowest limit proposed.

The SPR does not discuss LAER for NO_x in terms of the regulatory criteria for LAER which we have described in our comment #7 above. The SPR for the Block 2 project should include an explanation for NO_x LAER along the lines of the explanation provided on August 14, 2006 for PM_{10} LAER, updated as necessary to reflect the latest information.

Emission offset comments:

9. Lack of demonstration of positive net air quality benefit for offsets. This comment is very similar to a comment we submitted on December 9, 2004, on permitting of the Lake Side Block 1 project. We wrote that Utah's SIP-approved rules at R307-1-3.3.2.C.(4) (now SIP rule R307-403-3(3)(d)), require that "the emission offsets provide a positive net air quality benefit in the affected area of nonattainment." We stated that could find no explanation in the permit record for the Block 1 project how this requirement will be satisfied. We explained that we view this requirement as separate and independent from the requirement in Utah's SIP-approved rules at R307-1-3.3.3.B.(2) (now SIP rule R307-403-5(1)(b)), to obtain 1.2-to-1 offsets.

In its August 14, 2006 response to our December 9, 2004 comment, the State provided the following explanation for positive net air quality benefit for the Block 1 project:

> *Summit Vineyard [on behalf of Pacificorp] has obtained emission offset credits from those originally created by banking the emissions from the now closed Geneva Steel site. In this particular case, the emission offsets are from a location very close to the proposed plant site. Summit Vineyard has proposed to build on property purchased from Geneva Steel. This property is adjacent to the former steel mill. The emissions offsets obtained from the former steel mill are from emissions points somewhat similar in height, stack gas temperature, and flow rates. The proposed emissions from Summit Vineyard are also being offset under a 1.2 to 1 ratio, and on a pollutant-by-pollutant basis. The offset ratio and the proximity of the offset credits to the proposed location ensure that a positive net air quality benefit is achieved.*

The SPR for the Block 2 permit should similarly include an explanation or demonstration of positive net air quality benefit.

Further, there are no statements documenting where the required emission offsets were obtained from, nor how the offsets obtained remain practically enforceable at the other facility. The permit record also fails to indicate the quantity of offsets obtained. Section 7.0 of the permit application merely indicates that the required offsets are 141 tpy for PM_{10}, 194 tpy for NO_x, and 30 tpy for SO_2.

In our December 9, 2004 comments on permitting of the Block 1 project, we noted these same shortcomings in the permit record for Block 1. (See comment #1 of our enclosed 2004 letter.) We recommended that the permit record specifically describe how the offsets meet the relevant requirements that they be surplus, actual, and federally enforceable at the time the permit is issued. We cited CAA section 173(a), 42 U.S.C. section 7503(a). We also cited our comment letters on other major NSR proposed permits in Utah's PM10 nonattainment area (e.g., Calpine and Gadsby), which outlined why it is necessary for offsetting reductions to be in terms of actual emissions.

In summary, the SPR for the Block 2 project should provide an adequate explanation of offsets and net air quality benefit, indicating specifically where the emission offsets were obtained from and in what quantities, how the offsets obtained remain practically enforceable at the other facility, and how the ambient effect of the offsetting emission reductions compares to the ambient effect of the expected emission increases from the Block 2 project. In our preliminary modeling comments on the Block 2 project, submitted via letter to the State on July 21, 2010, we also indicated that near field AERMOD modeling results for PM_{10} could be a useful tool, in conjunction with modeling results from offset sources, to demonstrate a positive net air quality benefit for PM10.

10. Lack of permit enforceability of offset requirements. In our December 9, 2004 comments on permitting of Block 1, we wrote that the final Approval Order (AO) for Block 1 should include a requirement to obtain (and continue to hold) offsets sufficient to satisfy the SIP rule requirements for offsets in the PM_{10} nonattainment area. (See comment #1 of our 2004 letter.) In its August 14, 2006 response to our comment, the State said it agreed with us and would include, in the final AO for Block 1, a reference to the exact amount of emission offsets required, and in what ratio. The State's 2006 response also indicated that those values for Block 1 are 114.96 tpy for PM_{10}, 165.96 tpy for NO_x, and 31.8 tpy for SO_2.

We find, however, that the ITA which now encompasses Blocks 1 and 2 does not list the required offsets for either Block. Consistent with SIP rules at R307-403-5(1)(b), and consistent with CAA section 173(a) cited in comment #9 above, the exact amount of offsets required to be obtained (and continue to be held) should be included in the final AO for Blocks 1 and 2.

11. The combined three-pollutant plantwide emission limit should be expressed on a pollutant-specific basis, and the purpose of the limit should be explained in the SPR. Condition II.B.1.b. of the ITA specifies a plantwide emissions limit of 551.9 tons per calendar year, for the combined emissions of $PM_{10} + SO_2 + NO_x$. This limit is the same as the plantwide PTE figure listed in the ITA Abstract, for the sum of these three pollutants. The SPR does not explain the purpose for this limit.

We made a similar comment on December 9, 2004, on permitting of the Block 1 project. (See comment #1 of our enclosed 2004 letter.) The three-pollutant limit at that time reflected the PTE of Block 1. We said the limit appears to be a requirement to keep emissions below the offset baseline, and if this is the case, then the requirement should be expressed on a pollutant-specific basis, not the combination of three pollutants. We also noted that this three-pollutant limit does not serve the purpose of ensuring that the permittee obtains (and continues to hold), the quantity of emission offsets required by SIP rules.

In its Response-to-Comments memo, dated August 14, 2006 (at response #8), the State explained that the purpose of the three-pollutant limit is to ensure that no further offsets are required. The State also explained that the initial ratio of offsets required is set at the time of issuance of the AO, which is based on the emission limitations found in this permit condition, and in the estimates of total emissions for the entire plant. The State did not address our comment that the limit should be expressed on a pollutant-specific basis, not as the combination of three pollutants.

In our approval of Utah's NSR rules, we indicated that interpollutant offsets for major sources and modifications are not allowed, with one exception -- increases in PM10 precursors may be offset by reductions in PM10. See 60 FR 22281-282, May 5, 1995:

> *EPA currently only allows restricted interpollutant trading between PM-10 and PM-10 precursors. Specifically, new major sources or major modifications of a PM-10 precursor are allowed to obtain offsets from reductions in PM-10. Otherwise, new major sources and major modifications must obtain offsets from reductions in the same pollutant.*
>
> *As discussed above under "Applicability of Utah's Nonattainment NSR Provisions," UACR R307-1-3.1.8.B specifically provides that the Executive Secretary may only issue a permit if it is determined to be in accord with the "new source review requirements for nonattainment areas under the Federal Clean Air Act." Thus, in order for the State to comply with this provision, the State must interpret its regulations as stated in the above paragraph.*

We note also that 40 CFR part 51, Appendix S, does not allow for interpollutant offsets, with limited, constrained exceptions for $PM_{2.5}$.

In summary, the limit currently expressed as a three-pollutant limit should be expressed in the permit on a pollutant-specific basis, and the SPR for the Block 2 project should confirm whether the explanation for the limit remains the same as presented in 2006.

<u>Modeling comments:</u>

Region 8 reviewed modeling results submitted by Pacificorp to the State in the permit application addendum ("NOI Addendum") dated August 2, 2010. Comments and recommendations listed below are based on that document and on the State's memorandum titled, "Second Addendum to Modeling Analysis Review for the Summit Vineyard, LLC – Lake Side #2 Power Plant (LSPP2) near Vineyard, Utah" dated January 6, 2011. Region 8 has not received a copy of the "Second Addendum to Modeling Analysis" by Pacificorp and is requesting a copy of this document.

Region 8 has the following comments on the 1-hr NO_2 modeling based on a review of the August 2, 2010 NOI Addendum:

12. Missing explanation regarding "competing" sources. Following EPA modeling guidance in 40 CFR 51 Appendix W, Table 8-2, for the cumulative impact analysis of 1-hr NO_2, we recommend modeling nearby sources at the maximum allowable emissions limit or federally enforceable permit limit. It appears that actual emissions rates were used for nearby sources other than Lakeside Block 1. Also related to the cumulative 1-hr NO_2 modeling, Table 5-1 lists "competing" sources used in the NAAQS and PSD increment analyses, and Table 5-8 lists competing sources used in the 1-hr NO_2 NAAQS analysis. Some sources listed in Table 5-1 are not included in Table 5-8. Region 8 is requesting explanation of how sources were selected for the cumulative impact analysis and why some sources from Table 5-1 were excluded from the 1-hr NO_2 analysis. Also, Pacificorp appears to be listed twice in Table 5-1. Please explain if this was a mistake or whether it represents a separate Pacificorp facility.

13. Emissions monitoring data or manufacturer test data should be used to determine NO_2/NO_x ratio. A default ratio of 10% was used for NO_2/NO_x. EPA modeling guidance just released for the 1-hr NO2 NAAQS states that the NO2/NOx ratio should be based either on emission monitoring data or (in the absence of appropriate source-specific in-stack data) a default ratio of 50% (0.5). The modeling guidance is titled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard," dated March 1, 2011, and is available on EPA website at:

> http://www.epa.gov/ttn/scram/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

> In our March 1, 2011 guidance, we said,

> *"Although well-documented data on in-stack NO_2/NO_x ratios is still limited for many source categories, we also feel that it would be appropriate in the absence of such source-specific in-stack data to adopt a default in-stack ratio of 0.5 as being adequately conservative in most cases and a better alternative to use of the Tier 1 full conversion or Tier 2 ambient ratio options. This value appears to represent a reasonable upper bound based on the available in-stack data. We hope that over time the range of source categories for which in-stack ratio information is available increases and the quality of such information will improve."*

Moreover, in a June 2010 guidance memo on the implementation of the hourly NO_2 standard ("Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program"), we disavowed the use of the 0.1 default for the hourly standard, saying:

> *"Assumptions regarding in-stack NO_2/NO_x ratios that may have been deemed appropriate in the context of the annual standard may not be appropriate to use for the new 1-hour standard. In particular, it is worth reiterating that the 0.1 in-stack ratio often cited as the*

"default" ratio for OLM should not be treated as a default value for hourly NO_2 compliance demonstrations."

This guidance is available on the EPA website at:

http://www.epa.gov/nsr/documents/20100629no2guidance.pdf

Consistent with our previous guidance on NO_2/NO_x ratios for 1-hr NO_2 modeling, we recommend that the State and Pacificorp consider the use of either NO_2 in-stack emissions monitoring data for Lakeside Block 1 for startup/shutdown or normal operating conditions, as appropriate, to determine the actual NO_2/NO_x ratio. If appropriate source-specific in-stack emissions monitoring data are not available, we recommend using the default ratio of 50% NO_2/NO_x.

14. Concerns regarding modeling approach for 1-hour NO_2 impacts.

A. Introduction.

Pacificorp's permit application addendum dated August 2, 2010 shows 1-hr NO_2 impact to be about 90% of the NAAQS; however, the State's modeling memo, dated January 6, 2011, states that the second permit application addendum by Pacificorp showed 1-hr NO_2 impacts to be 98% of the NAAQS. As stated above, Region 8 has not received a copy of the second permit application addendum and is requesting copies of any additional modeling data that have been submitted for this project. The State's January 6, 2011 modeling memo further states:

In cases where the impact from a proposed PSD project under normal operations is predicted to be above 90% of a NAAQS, compliance with the air quality standard is considered to be 'threatened'. New or modifying source with model predicted impacts above 90% of a NAAQS are then required to conduct post-construction ambient monitoring for that pollutant to ensure that impact from the source does not result in a violation of the NAAQS.

The State subsequently remodeled 1-hr NO_2 using normal operating emissions for Blocks 1 and 2 instead of maximum startup/shutdown emissions. The State estimated 1-hr NO_2 impacts of 8 $\mu g/m^3$ from Blocks 1 and 2 under normal operating conditions for a total 1-hr NO_2. Combining this with background of 103 $\mu g/m^3$, the State estimated a total impact of 111 $\mu g/m^3$ (NAAQS is 188 $\mu g/m^3$) and therefore did not recommend additional monitoring.

B. EPA recommendations:

(i) Modeling adjustments to address startup/shutdown. Startups and shutdowns are expected to occur frequently for CTGs, and EPA therefore recommends the maximum emissions rate for startups/shutdowns should be modeled when evaluating the 1-hr NO_2

standard here. Thus, in this situation all applicable emissions should be used for the 1-hr NO_2 modeling. If the permit conditions stipulate that not more than one turbine can be operated under startup/shutdown conditions at any time, EPA recommends that startup/shutdown emissions for one turbine be combined with normal operating emissions limits for the remaining turbines.

(ii) Additional options to consider for modeling and associated permit conditions, to assure 1-hour NO_2 NAAQS compliance. There are some additional options that can be further evaluated for the 1-hr NO_2 modeling:

- EPA is releasing an updated version of the AERMOD model that correct a problem with the "urban" land use option. Region 8 recommends that the 1-hr NO_2 analysis be performed with the updated AEROMOD using the urban option.

- It is possible that some sources included in the cumulative modeling might also be represented in the background monitoring site, thereby resulting in double counting of those emissions. Region 8 recommends that an evaluation of the spatial distribution of modeled 1-hr NO_2 be performed, including an analysis of the meteorology data, to determine if any sources are being double counted.

- It might also be possible to specify permit conditions that would result in lower NO_x emissions rates. For example, Pacificorp could propose enforceable permit conditions that would limit simultaneous operation of CTGs or blocks in startup/shutdown mode. Maximum hourly emission rates incorporating such restrictions could be used in the 1-hr NO_2 modeling.

- If revised modeling shows that the modeled 1-hr NO_2 concentration continues to exceed 90% of the NAAQS, Region 8 recommends that post-construction monitoring be performed to evaluate attainment of the 1-hr NO_2 NAAQS.

Other comments:

15. Permit language giving the State the sole discretion to approve alternative test methods should be removed from the permit. In regard to testing for PM_{10}, NO_x and CO emission compliance, as well as testing for volumetric flow rate, ITA Conditions II.B.2.d (for Block 1) and II.B.3.d (for Block 2) each contain eight instances of the clause "other testing methods approved by the Executive Secretary," or similarly worded clauses, that give the State the sole discretion to approve alternative test methods without EPA approval.

Under provisions for SIP-approved programs, at 40 CFR 51.212 ("Testing, inspection, enforcement and complaints"), States may use, as enforceable methods, the methods in 40 CFR 51 Appendix M, or in 40 CFR 60 appendix A, or an alternative method following review and approval of that method by the Administrator. A letter dated March 31, 1994, from EPA's Office of Air Quality Planning and Standards to the State of Iowa (available on EPA's NSR Policy and Guidance website), makes it clear that EPA interprets "Administrator" in §51.212 to mean only the *EPA* Administrator. The letter also said that the SIP-approved programs covered in §51.212 include PSD permitting programs.

Consistent with §51.212, the Utah SIP contains no provisions giving the State the sole discretion to approve alternative test methods. The applicable SIP rule cited in the Lake Side permit, as the basis for Conditions II.B.2.d and II.B.3.d, is R307-165. There is nothing in that rule that says the state has such sole discretion. R307-165 does not mention the option of requesting approval of alternative test methods, by either the State or EPA. SIP rule III.E, "Source Surveillance," also contains no language giving the State the sole discretion to approve alternative methods, but does specifically require EPA approval.

We have raised this issue in previous comment letters to the State on NSR permit actions. (Examples: comment letter dated April 20, 2004 on Pacificorp Currant Creek; comment letter dated April 6, 2004 on Sevier Power Company Project.) We cited the 1994 letter to Iowa and asked the State to remove such 'sole discretion' clauses from the permit. The State agreed with our comment in each case and committed to make the appropriate change in the final Approval Order for each project. (Ref: response memo on Sevier Creek dated September 27, 2004, at responses #90 and 97; response memo on Currant Creek dated March 1, 2011 – apparently misdated – at response #7).

The State should remove such clauses with respect to all test methods referenced in the Lake Side permit. Our position on this also applies to any other permit issued by the State. An example of appropriate replacement language may be found in section IX.H.1 of the EPA-approved PM_{10} SIP rules, General Requirements for sources in the Utah County PM10 nonattainment area. Instead of "other testing methods approved by the Executive Secretary," these rules say "other appropriate EPA approved reference method."

16. Permit condition I.2 should be reworded to make it clear that it is not intended as a way to avoid Utah rule requirements for public notice and opportunity for comment on AOs. Permit condition I.2 says "The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]" While we doubt it is the State's intent that this condition be used to relax AO conditions without public notice and opportunity for comment, we are concerned that it could be interpreted this way by permittees. Until recently, this permit condition in AOs said, "The limits set forth in this AO shall not be exceeded without prior approval *in accordance with* R307-401." This earlier wording of the permit condition made it clearer that the condition was not intended to allow AO relaxations without public notice and opportunity for comment, which is part of the AO issuance process required by R307-401. The condition should be reworded to make this clear again.

17. ITA condition I.6. on unavoidable breakdowns should be removed. This comment is the same as comment #18 in our December 9, 2004 comment on the ITA for the Block 1 project. The State should remove ITA condition I.6, which references the State's unavoidable breakdown rule. We have advised the State on a number of occasions that the unavoidable breakdown rule is not consistent with EPA interpretation of the Clean air Act. The State has committed to work to address EPA concerns with a SIP revision. Most recently, EPA proposed to issue a SIP call

regarding the rule. To ensure that permits do not provide inappropriate exemptions from emissions limitations that cannot be changed later, and in light of the fact that the unavoidable breakdown rule currently applies whether or not it is referenced in the permits, the reference to that rule should be removed from the ITA.

In response to our December 9, 2004 comment, the State said the condition on unavoidable breakdowns would be removed from the final AO for Block 1. (Ref: Response-to-Comments memo by the State, dated August 14, 2006, at response #25.) However, we note that this condition is still in the AO.

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

APPLICATION FOR CERTIFICATION FOR THE *CARLSBAD ENERGY CENTER PROJECT*

Docket No. 07-AFC-6
PROOF OF SERVICE
(Revised 11/29/2011)

APPLICANT
Jennifer Hein
George Piantka, PE.
NRG Energy, Inc., West Region
5790 Fleet Street, Ste. 200
Carlsbad, CA 92008
jennifer.hein@nrgenergy.com
george.piantka@nrgenergy.com

APPLICANT'S CONSULTANTS
Robert Mason, Project Manager
CH2M Hill, Inc.
6 Hutton Centre Drive, Ste. 700
Santa Ana, CA 92707
Robert.Mason@ch2m.com

Megan Sebra
CH2M Hill, Inc.
2485 Natomas Park Drive, Ste. 600
Sacramento, CA 95833
Megan.Sebra@ch2m.com

COUNSEL FOR APPLICANT
John A. McKinsey
Stoel Rives, LLP
500 Capitol Mall, Suite 1600
Sacramento, CA 95814
jamckinsey@stoel.com

INTERESTED AGENCIES
California ISO
e-recipient@caiso.com

INTERVENORS
Terramar Association
Kerry Siekmann & Catherine Miller
5239 El Arbol
Carlsbad, CA 92008
siekmann1@att.net

City of Carlsbad
South Carlsbad Coastal
Redevelopment Agency
Allan J. Thompson
21 "C" Orinda Way #314
Orinda, CA 94563
allanori@comcast.net

City of Carlsbad
South Carlsbad Coastal
Redevelopment Agency
Joseph Garuba,
Municipals Project Manager
Ronald R. Ball, Esq., City Attorney
1200 Carlsbad Village Drive
Carlsbad, CA 92008
Joe.Garuba@carlsbadca.gov
ron.ball@carlsbadca.gov

California Unions for Reliable Energy (CURE)
Marc D. Joseph
Adams Broadwell Joseph & Cardozo
601 Gateway Boulevard, Suite 1000
South San Francisco, CA 94080
gsmith@adamsbroadwell.com
mdjoseph@adamsbroadwell.com

Center for Biological Diversity
c/o William B. Rostov
EARTH JUSTICE
426 17th Street, 5th Floor
Oakland, CA 94612
wrostov@earthjustice.org

Power of Vision
Julie Baker & Arnold Roe, Ph.D.
4213 Sunnyhill Drive
Carlsbad, California 92013
julbaker@pacbell.net
roe@ucla.edu

Rob Simpson
Environmental Consultant
27126 Grandview Avenue
Hayward, CA 94542
rob@redwoodrob.com

April Rose Sommer
Attorney for Rob Simpson
P.O. Box 6937
Moraga, CA 94570
aprilsommerlaw@yahoo.com

ENERGY COMMISSION – DECISIONMAKERS
JAMES D. BOYD
Vice Chair and Presiding Member
jboyd@energy.state.ca.us

KAREN DOUGLAS
Commissioner and Associate Member
kldougla@energy.state.ca.us

Galen Lemei
Adviser to Commissioner Douglas
glemei@energy.state.ca.us

Tim Olson
Adviser to Vice Chair Boyd
tolson@energy.state.ca.us

Paul Kramer
Hearing Officer
pkramer@energy.state.ca.us

ENERGY COMMISSION STAFF
Mike Monasmith
Siting Project Manager
mmonasmi@energy.state.ca.us

Dick Ratliff
Staff Counsel
dratliff@energy.state.ca.us

ENERGY COMMISSION – PUBLIC ADVISER
Jennifer Jennings
Public Adviser's Office
publicadviser@energy.state.ca.us

*indicates change

Declaration of Service

I, Robin Nuschy, declare that on, 12·7·11, I served and filed copies of the attached Prepared Supplemental Testimony of Matthew Zinn dated 12·7·11. The original document, filed with the Docket Unit or the Chief Counsel, as required by the applicable regulation, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at: **[www.energy.ca.gov/sitingcases/carlsbad/ index.html]**.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(*Check all that Apply*)

For service to all other parties:

X Served electronically to all e-mail addresses on the Proof of Service list;

X Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses marked "hard copy required."

AND

For filing with the Docket Unit at the Energy Commission:

X by sending an original paper copy and one electronic copy, mailed with the U.S. Postal Service with first class postage thereon fully prepaid and e-mailed respectively, to the address below (preferred method); ***OR***

____ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 07-AFC-6
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.state.ca.us

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

X Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
mlevy@energy.state.ca.us

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

Robin Nuschy