EARTHJUSTICE

BOZEMAN, MONTANA DENVER, COLORADO HONOLULU, HAWAII
INTERNATIONAL JUNEAU, ALASKA NEW YORK, NEW YORK OAKLAND, CALIFORNIA
SEATTLE, WASHINGTON TALLAHASSEE, FLORIDA WASHINGTON, D.C.

January 22, 2009

VIA U.S. AND ELECTRONIC MAIL

Weyman Lee
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
weyman@baaqmd.gov

Re: Draft Amended PSD Permit for Russell City Energy Center

Dear Mr. Lee:

This letter is submitted on behalf of Citizens Against Pollution to urge you not to approve the draft prevention of significant deterioration ("PSD") permit as proposed for the Russell City Energy Center. The draft permit fails to meet federal PSD requirements relating to the need for best available control technology ("BACT") and the prevention of air quality impacts that will cause or contribute to violations of the national ambient air quality standards ("NAAQS"). In particular, while we applaud the District and the project applicant for the decision to include for the first time a limit on emissions of carbon dioxide (CO2), the limit selected and the analysis supporting that limit are defective. Because the control of CO2 emissions in a PSD permit is new and precedent-setting, it is all the more important that the standard-setting exercise be done correctly.

<u>Determination of Carbon Monoxide (CO) BACT Limit</u>

The District concludes that "the lowest [CO] emissions that these turbines can reasonably achieve using good combustion practices with an oxidation catalyst is 4.0 [parts per million (ppm)] @ 15% 02 (3-hour average)." Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit at 35 (Dec. 8, 2008) (hereinafter "Statement of Basis"). This conclusion, however, is not supported by the evidence provided by the District.

The District identifies numerous facilities that have CO limits of less than 4.0 ppm even with NOx limits of 2.0 ppm. *See* Statement of Basis at 33-34 (Table 11). The relevant sources are reproduced below:

| Facility | NOx Limit (ppmvd @ 15% O2) | CO Limit (ppmvd @ 15% O2) | Operational Status |
|---|---|---|---|
| ANP Blackstone, MA-0024 | 2 (1-hr) No steam<br>3.5 (1-hr) Steam Inj. | 3.0 (1-hr) | In Operation |
| Goldendale Energy | 2 (3-hr) | 2 (1-hr) | In Operation |
| Magnolia, SCAQMD | 2 (3-hr) | 2 (1-hr) | In Operation |
| Sierra Pacific Power Co. Tracy Station, NV-0035 | 2 (3-hr) | 3.5 (3-hr) | Unknown |
| Welton Mohawk, AZ-0047 | 2 (3-hr) | 3 (3-hr) | Unknown |
| Colusa Generating Station | 2 (1-hr) | 3 (3-hr) | Not built |
| Turner Energy Center, OR-0046 | 2.0 (1-hr) | 2.0 (3-hr) > 70% load<br>3.0 (3-hr) < 70% load | Not built |
| Wanapa Energy Center, OR-0041 | 2.0 (3-hr) | 2.0 (3-hr) | Not built |
| Morro Bay – Duke | 2.0 (1-hr) | 2.0 (3-hr) | Not built |
| Sumas Energy 2, WA-0315 | 2 (3-hr) | 2 (1-hr) | Not built |
| IDC Bellingham, MA | 1.5 (1-hr) | 2 (1-hr) | Not built |
| CPV Warren, VA-0308 | 2 (1-hr) | 1.2 to 2.5 (3-hr) | Not built |

The District's first argument for refusing to set a lower CO limit conforming with the limits set for these other sources is that there is a tradeoff between NOx and CO performance, and the NOx limits set for these other permits are less stringent than the 1-hour average limit of 2.0 ppm proposed for the Russell City Energy Center. Statement of Basis at 34-35. The first problem with the District's claim is that there is no record basis for the asserted need to tradeoff CO stringency for NOx stringency. While we recognize the theoretical relationship between NOx and CO performance, the record shows that there is no unavoidable need to sacrifice CO stringency in exchange for protective NOx controls. To the contrary, the District's table shows that lower and lower CO limits have been imposed without any relaxation in the stringency of the NOx limits.

Second, the District's argument, even if true, does not support the decision to adopt a CO limit of 4.0 ppm. The District claims that meeting the proposed 2.0 ppm 1-hour NOx limit will make achieving a 2 ppm CO limit "much more difficult" but does not claim or offer any analysis to support a claim that such a limit is infeasible or not cost-effective. Nor is there any analysis of limits between 2.0 and 4.0 ppm.

Several sources have limits of 2 ppm for NOx (albeit with 3-hour averages) and 2 ppm for CO (*e.g.*, Goldendale, Magnolia, Wanapa, and Sumas Energy). The District offers no basis for its assertion that if the NOx limits for these identified sources were tightened from 3-hour averages to 1-hour averages, that the CO emission limits would need to be raised from 2 ppm all the way to 4 ppm. In particular, for Goldendale and Magnolia, which are already in operation, the District focuses on the NOx averaging period, but seems to ignore the fact that the CO averaging period is much more stringent than the period proposed for Russell City. Similarly, the ANP Blackstone facility, which is also in operation, must meet a 1-hour NOx limit of 2.0 ppm along with a *1-hour* CO limit of 3.0 ppm. In order to determine what limits are feasible, the District should look at the 3-hour average CO concentrations achieved by these operating sources during periods where 1-hour NOx averages are below 2.0 ppm.

The District's second argument for refusing to set a lower CO limit is that a lower limit cannot be consistently achieved at low loads and under rapidly changing load conditions. Again the District's analysis does not support the selected limit. The data collected by the District show that the less protective limit of 4.0 ppm is only appropriate for periods of low load. During normal, full-load periods, the Metcalf data reported by the District, Statement of Basis at 32-33, as well as notes from the ANP Blackstone permit (attached hereto as Exhibit A), show that limits of 2.0 ppm can be achieved. The solution, therefore, is not to default to the lowest common denominator in setting the BACT limit, but to set separate limits for normal and low-load condition. As shown in the table above, this was the approach taken in ANP Blackstone and Turner Energy Center. For the same reasons that separate limits are established for periods of startup and shutdown, separate limits are appropriate to ensure that BACT is achieved during all operating conditions. The District admits that the proposed limit is set based on emissions expected "under some conditions." Statement of Basis at 35. This is not the proper way to establish a BACT limit. The proposed 4.0 ppm limit for CO does not represent BACT during normal load operations. If the District believes that the limit for normal operations is not appropriate for "some conditions" then the District should analyze what the appropriate limit or averaging time should be for those conditions and set a separate limit accordingly.

We question, however, the District's unsupported assertion that the load changing characteristics of the proposed Russell City project preclude achieving a lower CO limit. The recently proposed Carlsbad Energy Center project is a *retrofit* of a peaking energy power plant (i.e., more dramatic changes in load than a baseload plant). Carlsbad Energy Center will meet a 2.0 ppm (1-hour average) NOx limit while also meeting a 2.0 ppm (1-hour average) CO limit. *See* Preliminary Staff Assessment, Carlsbad Energy Center Project (07-AFC-6) (CEC-700-2008-014-PSA), at 4.1-70 (Dec. 11, 2008). As recommended above, to address the challenges of shifting loads, the proposed Carlsbad permit includes a 3-hour averaging period to meet the 2.0 ppm limit during any transient hour. *See id*.

It is clear that the 4.0 ppm limit proposed for Russell City is outdated and no longer supportable. The District must revise the BACT limit for CO for normal operations to at least 2.0 ppm (1-hour average) to comport with current permitting levels. To the extent a separate limit is needed for other operating conditions, the District must define those conditions and justify the BACT limit selected.

Determination of BACT Limit for Carbon Dioxide (CO2)

At the outset, we want to commend the District and the applicant for acknowledging the need to set a limit for emissions of CO2. Notwithstanding EPA's recent illegal attempt to change its interpretation of existing law,[1] CO2 is a pollutant "subject to regulation" under the Clean Air Act and, as a result, must be controlled using the best available control technology. Unfortunately, the District has failed to conduct a proper BACT analysis for CO2 and has proposed a limit that has no legitimate technical basis. Given the importance of this precedent-setting decision, we urge the District to redo the analysis and give it the proper attention that it deserves.

The first failure in the BACT analysis is the refusal to look at the full range of alternatives to reduce CO2 emissions from the proposed project. These should have included energy production alternatives that do not rely on fossil fuel combustion,[2] hybrid technologies that combine energy sources to improve the overall carbon efficiency of the power plant,[3] requiring co-generation with the project, and changes to the project design that would lower total carbon emissions (e.g., elimination of supplemental duct burners for the heat recovery steam generators, or replacement of those burners with a more efficient microturbine or solar energy collection system[4]). The District's analysis instead focuses primarily on turbine efficiency, but even then seeks to justify a standard that can be met by the old turbines that the applicant has already purchased[5] rather than truly exploring what level of emissions can be achieved using best available technologies.

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[1] We have attached for the record, the petition for reconsideration filed by the Sierra Club, Natural Resources Defense Council and others (Ex. B, hereto) outlining the legal defects with EPA's December 31, 2008 "Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program." Should the District decide that a BACT limit for CO2 is not required by the Clean Air Act based on EPA's announcement, we incorporate by reference the legal analysis in the petition for reconsideration explaining why EPA's final action is illegal.

[2] We note that an analysis of non-fossil fuel alternatives is consistent with other State initiatives such as the Air Resources Board's Scoping Plan under the Global Warming Solutions Act (AB32), which calls for the adoption of a 33 percent renewable performance standard (RPS) to be achieved by 2020. *See* http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf. The California Public Utilities Commission has concluded, "if the State is required to generate 33% of its energy from renewable resources by 2020, then all new procurement of new energy resources between now and 2020 must be entirely renewable energy . . . ." CPUC, Renewables Portfolio Standard Quarterly Report, at 10 (Oct. 2008).

[3] *See, e.g.*, http://www.energy.ca.gov/sitingcases/victorville2/index.html (Victorville 2); http://www.reuters.com/article/environmentNews/idUSN1139875020080612 (PG&E Coalinga project); http://my.epri.com/portal/server.pt/gateway/PTARGS_0_237_317_205_776_43/http;/uspalecp604;7087/publishedcontent/publish/epri_to_evaluate_adding_solar_thermal_energy_to_fossil_power_plants_da_609034.html (EPRI projects).

[4] *See, e.g.*, http://appft1.uspto.gov/netacgi/nph-Parser?Sect1=PTO1&Sect2=HITOFF&d=PG01&p=1&u=/netahtml/PTO/srchnum.html&r=1&f=G&l=50&s1='20080127647'.PGNR.&OS=DN/20080127647&RS=DN/20080127647 (application for patent on solar energy system to supplement thermal energy for heat recovery steam generators).

[5] *See* Statement of Basis at 41 n.31 (rejecting use of Fast Start Technology because applicant has already purchased its equipment). *See also* E-mail from Brian Lusher, Air Quality Engineer, BAAQMD, to Weyman Lee, Senior Air Quality Engineer, BAAQMD (Sept. 10, 2008) (noting "the project owner purchased the combustion turbines and steam turbine generator [in 2001]") (attached hereto as Ex. C).

In exploring the efficiency of available turbine technologies, the District relies on the outdated 2002 analysis prepared by the CEC which looked at three turbines and found efficiencies between 55.8 and 56.5 percent. *See* Statement of Basis at 64 n.66. The District notes that the CEC conducted a subsequent project review in 2007 and concluded that the proposed changes to the Russell City plant would not change any of the original conclusion. To the extent the District is trying to suggest that the 2002 review of turbine efficiencies remains valid, that claim is plainly false. The CEC did not review the whether turbine efficiencies had improved over the ensuing 5 years, but instead only looked at whether the amendments to the proposed project would alter the efficiency of the project. *See* Staff Assessment – Part 1 and Part 2 Combined, Amendment No. 1 (01-AFC-7C) at 5.3-1 (June 2007) (CEC-700-2007-005-FSA). Had the District properly conducted a review of current turbine efficiency it would have discovered that efficiencies have significantly improved with newer technology. Of particular note is General Electric's H system turbines, which can reportedly achieve greater than 60 percent efficiency. *See* www.gepower.com/prod_serv/products/gas_turbines_cc/h_system/index.htm. These turbines have been in operation in Balgan Bay, Wales since 2003 and at the Tokyo Electric Power Company's Futtsu Thermal Power Station in Japan since 2007. *See* Ex. D. These turbines have also been proposed for use at the Inland Empire Energy Center here in California. *Id.*[6]

Moreover, even using the outdated efficiency data collected by CEC in 2002, it is clear on the face of the record that the turbines proposed for use at Russell City do not represent the best available control technology. The CEC found that efficiencies of new turbine technologies available in 2002 ranged from 55.8 to 56.5 percent. The turbines that the applicant has already purchased are at the bottom end of this efficiency range but the District makes not attempt to explain why more efficient turbines could not have been required as BACT. *See* Statement of Basis at 64.

The next step in the District's analysis is completely disconnected from the initial review of turbine efficiency. The District says it looked at CO2 emissions levels from existing sources "[t]o determine an appropriate CO2 emissions limitation achievable for this level of energy-efficient technology . . . ." Statement of Basis at 64. The District points to undocumented "information" from the CEC showing 2004 and 2005 emissions from baseload combined-cycle gas turbine plants ranged from 794 to 1058 lb/MW-hr.[7] The District provides no analysis relating this emissions data to the efficiency of the turbines. We presume the upper end of the emissions range reflects the emission rates of older, less efficient turbines and is not relevant for determining the CO2 emission level that should be achievable with modern, efficient turbine technology.

[6] Westinghouse has also introduced its advanced turbine system (ATS) program with preliminary results demonstrating efficiencies over 60 percent. *See* Ex. E.

[7] These emission data appear to be the same as that described by the California Public Utilities Commission in its SB1368 proceeding. As will be discussed below, the range of reported emissions includes "outlier" sources that do not reflect best available turbine technology and include the effects of unfavorable operating environments such as high altitudes. The blind application of this data is not appropriate for determining CO2 BACT for the Russell City project.

The two specific examples the District actually provides – Delta Energy Center and the Metcalf Energy Center – both use the Siemens-Westinghouse 501F turbines proposed for Russell City. *See* Final Staff Assessment (Part 1 of 2), Delta Energy Center, Application for Certification (98-AFC-3) at 339 (Sept. 10, 1999); Commission Decision, Metcalf Energy Center, Application for Certification (99-AFC-3) at 68 (September 2001) (P800-01-023). The 2006 emissions data for these facilities show that even the older models of these turbines can achieve emissions well below the upper end of the range provided for all turbines (i.e., 855 lb/MW-hr for Delta Energy Center and 912 lb/MW-hr, for Metcalf Energy Center). The District, however, makes no attempt to review which turbines were able to achieve even lower emission levels as reported by the CEC or to explore what emissions levels could be achieved by more efficient available turbines. The District is assuming that the turbine technology for Russell City is fixed because the applicant has already purchased the turbines. This is not the proper way to conduct a BACT analysis.

The analysis of emissions levels should also include a review of permitting decisions for new sources as well. For example, the Carlsbad Energy Project, which is a retrofit of a peaking power plant (i.e., presumably less efficient than a new baseload plant), will emit 891 lb $Co_2$/MW-hr (.405 mt $CO_2$/MW-hr). *See* Preliminary Staff Assessment, Carlsbad Energy Center Project (07-AFC-6) (CEC-700-2008-014-PSA) at 4.1-102 (Dec. 11, 2008). The limited, undifferentiated emissions data that the District uses simply cannot form the basis for identifying *best* performance levels.

After identifying a range of emission levels, the District next asserts without any basis that in order to ensure compliance under all foreseeable operating conditions, "[b]ased on available data the Air District has reviewed for similar sources, and incorporating a reasonable compliance margin," BACT for $CO_2$ is 1100 lb/MW-hr, which conveniently happens to be the maximum level of $CO_2$ emissions allowed for such sources in the State of California. Statement of Basis at 65. This attempt to throw everything into the hat and magically pull out the California emission performance standard as BACT is not a technically defensible BACT determination.

First, as noted above, the available emissions data do not support the conclusion that even the outdated technology proposed for Russell City could emit up to 1100 lb $CO_2$/MW-hr. In fact, a review of the California Public Utilities Commission proceeding on SB1368, where the 1100 lb $CO_2$/MW-hr emission performance standard was developed makes clear that this level of emissions does not reflect the limit of what is achievable by new combined-cycle gas turbines in the State, but instead is what is achievable by most existing units, including "outliers" such as units using dry cooling technologies, or that are sited in less favorable locations such as deserts or at high altitude. *See In re Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework for Greenhouse Gas Emissions Standards into Procurement Policies*, Cal. Pub. Util. Comm'n, Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standards, R.06-04-009, Decision 07-01-039, at 64-69 (Jan 25, 2007). This limit represents the *minimum* carbon efficiency of these plants, not the maximum degree of emission reductions achievable.

The District's "reasonable compliance margin" is entirely arbitrary. Not only does the District fail to provide any data to support the need, let alone magnitude of such a margin, it never even explains what the margin is (i.e., what is the baseline emissions level and what is the margin added to it). A "reasonable compliance margin" can only be established in reference to the testing protocols used to measure the similar sources. That is, the District must explain (a) what test methods were used to test the other sources used to establish the limit, (b) what the reliability was for those test methods, and (c) why it is reasonable to assume from the tests that the emissions at those plants in reality vary to the degree claimed. Based on the 2006 data from Delta and Metcalf Energy Centers, the proposed limit suggests that actual CO2 emissions from those facilities may be 30 percent higher than reported levels. This seems highly doubtful and certainly is not a reasonable assumption with no underlying support.

The District attempts to build an argument based on opinions by the Environmental Appeals Board that limits must be set to ensure compliance under all foreseeable operating conditions. Statement of Basis at 65. The District, however, never explains what those foreseeable operating conditions might be and how they will affect CO2 emission levels. Moreover, even if there are such conditions, the appropriate response is to set different limits that assure best controls under all such conditions. Just as a permit could not use startup, shutdown and malfunction conditions to dictate the limit for all operating conditions, so the District cannot claim that the BACT limit must be set at the lowest common denominator of performance.

The arbitrariness of the District's BACT limit is highlighted in the final step of the analysis. The District uses the 1100 lb CO2/MW-hr emissions rate and the carbon content of natural gas to calculate the maximum hourly heat input that would be allowed to ensure the CO2 emissions rate is met. Statement of Basis at 65. The result of this calculation is 2944.3 mmBtu/hr for each turbine/heat recovery steam generator train. *Id.* This number is over 35 percent higher than the baseline maximum heat input of 2168 mmBtu/hr assumed for each power block! *See id.* at 84. Presumably because the District recognized the absurdity of setting a heat input limit higher than the uncontrolled maximum levels assumed for the project (though the District does not explain itself), the District set the actual heat input limit at 2238.6 mmBtu/hr. *Id.* at 65. This limit is still higher than the uncontrolled baseline assumptions on heat input. What this limit means is that the sources can be even less efficient than the already mediocre 55.8 percent level of efficiency reported for these turbines.

This heat input level is not a BACT limit. It has no connection to emission rates achievable by the best performing sources. Moreover, even if the District had used reasonable data to calculate the heat input limit, relying on such a limit alone does not assure BACT at all levels of operation. By only limiting fuel use, the limit may cap hourly emissions of carbon, but it does not ensure the turbines are being maintained to achieve their most efficient operation, which the District identifies at the outset is the basis for determining BACT. It is not enough to assert that sources will always ensure maximum efficiency because of a desire to minimize fuel costs. This simplistic view does not accord with the real world where we are all faced with decisions on when to invest our resources to achieve improvements in efficiency. Power plants are no different than home water heaters, automobiles or any other fuel-burning equipment in that we allow them to degrade, even though it costs us money in fuel, because the cost of maintenance or replacement acts as a barrier. The point of the BACT limit should be to ensure that efficiency is maintained – it is not enough to rely on voluntary decisions to use fuel efficiently. Setting a heat input limit is useful to cap total carbon emissions but is not sufficient to ensure BACT at all times. *See In Re Steel Dynamics, Inc.*, 9 E.A.D. 165, 224 (EAB 2000) (rejecting form of limits that did not ensure compliance on a continual basis at all levels of operation).

The District needs to completely redo the analysis of BACT for CO2 starting with a review of alternatives that do not rely on fossil fuel at all. The District's analysis has been improperly built around trying to justify the use of the turbines that the applicant has already purchased. This is inappropriate in the same way that determining a NOx limit around the prior purchase of aftertreatment technology other than SCR or of burners that are not low-NOx would be inappropriate. Given the extent of the defects in the CO2 BACT analysis in particular, we request that the District revise the draft Statement of Basis with new BACT analyses and recirculate it for another round of public comment.

<u>Analysis of Fine Particulate Matter (PM2.5) Impacts</u>

The District's analysis of PM2.5 air quality impacts is completely deficient. The Bay Area does not meet the national standards for PM2.5, and yet the District proposes to approve this project and allow unmitigated emissions in direct PM2.5 and PM2.5 precursors as if the addition of these emissions can be allowed without jeopardizing public health. The District attempts to hide behind EPA's illegal grandfathering exemption knowing full well that the air quality in the Bay Area is unhealthy and emissions of PM2.5 and its precursors need to be reduced. The District's strategy is misguided and highlights the illegality of EPA's grandfathering provision.

Air quality in the Bay Area violates the 2006 24-hour NAAQS for PM2.5 and the District has known this since at least December 2007. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Dec. 17, 2007) (state recommendations for area designations under the PM2.5 NAAQS based on 2004 through 2006 monitoring data) (Ex. F hereto). The State reevaluated and confirmed its recommendation to designate the Bay Area as nonattainment for PM2.5 based on 2005 through 2007 monitoring data. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Oct. 18, 2008) (Ex. G hereto). EPA signed its final rule designating the Bay Area as nonattainment for PM2.5 on December 22, 2008.

Put simply, the proposed project will violate section 165(a)(3) of the Clean Air Act, which provides:

> No major emitting facility . . . may be constructed in any area to which this part applies unless . . .the owner or operator of such facility demonstrates . . . that emissions will not cause, or contribute to, air pollution in excess of any . . . national ambient air quality standard in any air quality control region.

42 U.S.C. § 7475(a)(3). Air quality in the Bay Area already violates the 24-hour NAAQS for PM2.5. Thus, there is simply no dispute that the added emissions from the Russell City Energy Center will contribute to violations of the PM2.5 NAAQS in the Bay Area. To the extent EPA's

guidance or rules suggest that the District may ignore this statutory requirement, they are flatly illegal. Indeed, EPA has tried to defend its illegal policy by advising that:

> [T]he continued use of the PM10 surrogate policy is not mandatory, and case-by case evaluation of the use of PM10 in individual permits is allowed to determine its adequacy as a surrogate for PM2.5. If, under a particular permitting situation, it is known that a source's emissions would cause or contribute to a violation of the PM2.5 NAAQS, we do not believe that it is acceptable to apply the PM10 surrogate policy in the face of such predicted violation.

*See* Letter from Stephen L. Johnson, Administrator, EPA, to Paul Cort, Earthjustice, at 3 (Jan. 14, 2009) (Ex. H hereto).

Before this permit is final (especially if there is another challenge of the permit before the Environmental Appeals Board, which seems likely), the PM2.5 nonattainment designation for the Bay Area will become effective. Upon the effective date of the nonattainment designation, permitting of major sources of PM2.5 and its precursors will be subject to nonattainment new source review including the requirement to offset all new emissions and to apply more stringent control technologies. If the District's rules are not written to accommodate such requirements, appendix S of 40 CFR part 51 will apply for all such permitting. *See* 73 Fed. Reg. 28321, 28342 (May 16, 2008). Under federal rules, areas that are nonattainment for PM2.5 after July 15, 2008, will no longer be permitted to implement a nonattainment new source review program for PM10 as a surrogate for PM2.5 nonattainment new source review requirements. *See id.* The District's attempt to push through this permit without acknowledging that these added emissions will worsen the already unhealthy air in the Bay Area is unseemly and short-sighted. Instead, the District should proceed now to require the source to identify offsetting emissions and evaluate the lowest achievable emission rate for PM2.5 and its precursor emissions such as NOx.

<u>Conclusion</u>

The draft permit for the Russell City Energy Center must not be approved. The BACT analysis is built not to identify the "maximum degree of emission reduction . . . achievable," but to justify limits that can be achieved by the old turbines already purchased by the applicant. This is a plain violation of the Clean Air Act, which requires consideration of different production processes and methods, as well as innovative fuel combustion techniques for controlling emissions. *See*

CAA § 169(3). The District should prepare a new analysis and re-notice a revised draft permit for public review. In doing that new analysis, we urge the District to consider more broadly the alternatives available to addressing the energy needs purportedly served by the Russell City project.

Sincerely,

Paul Cort

Paul Cort
Staff Attorney

Cc: Debbie Jordan, EPA w/o enc.
Gerardo Rios, EPA w/o enc.

Enc.: Exhibit A – ANP Blackstone Energy Co. LAER BACT Determinations.

Exhibit B – Amended Petition for Reconsideration, *In re Interpretation of Regulations that Determine Pollutants Covered by the Federal PSD Permit Program* (Jan. 6, 2009).

Exhibit C – E-mail from Brian Lusher to Weyman Lee (Sept. 10, 2008).

Exhibit D – Materials on General Electric H System Combined Cycle Gas Turbine.

Exhibit E – Materials on Westinghouse's Advanced Turbine Systems Program.

Exhibit F – Letter from James N. Goldstene, Executive Officer, CARB, to Wayne Nastri, Regional Administrator, EPA Region 9 (Dec. 17, 2007).

Exhibit G – Letter from James N. Goldstene, Executive Officer, CARB, to Wayne Nastri, Regional Administrator, EPA Region 9 (Oct. 15, 2008).

Exhibit H – Letter from Stephen L. Johnson, Administrator, EPA, to Paul R. Cort, Earthjustice (Jan. 14, 2009).

# Attachment A

# Section II: Other LAER/BACT Determinations
## Application No.: 118969
## Equipment Category – Gas Turbine

| 1. GENERAL INFORMATION | | DATE: 4/16/2003 |
|---|---|---|
| A. MANUFACTURER: Asea Brown-Boveri (ABB) | | |
| B. TYPE: Combined Cycle | C. MODEL: GT-24 | |
| D. STYLE: | | |
| E. APPLICABLE AQMD RULES: | | |
| F. COST: $ (NA) | SOURCE OF COST DATA: | |
| G. OPERATING SCHEDULE: 24 HRS/DAY | 7 DAYS/WK | 52 WKS/YR |

| 2. EQUIPMENT INFORMATION | | APP. NO.: 118969 |
|---|---|---|
| A. FUNCTION: Power generation: two gas turbines rated at 180 MW each (210 MW w/ steam augmentation), two unfired HRSGs, two steam turbines rated at 95 MW each (85 MW in steam augmentation mode) | | |
| B. MAXIMUM HEAT INPUT: 3630 MMBtu/hr, 4367 MMBtu/hr w/ steam augmentation | C. MAXIMUM THROUGHPUT: | |
| D. BURNER INFORMATION: NO.: | TYPE: Dry Low NOx | |
| E. PRIMARY FUEL: Natural Gas | F. OTHER FUEL: None | |
| G. OPERATING CONDITIONS: Most operation expected to be at or near full capacity w/o steam augmentation. However, due to materials problems, the plant has derated the maximum power output on both power trains to 92% of design capacity. | | |

| 3. COMPANY INFORMATION | | | APP. NO.: 118969 |
|---|---|---|---|
| A. NAME: ANP Blackstone Energy Co. | | | B. SIC CODE: |
| C. ADDRESS: 204 Elm Street<br>CITY: Blackstone | STATE: MA | | ZIP: 01504 |
| D. CONTACT PERSON: Robert G. Maggiani | | E. PHONE NO.: 508-876-8114 | |

| 4. PERMIT INFORMATION | | | APP. NO.: 118969 |
|---|---|---|---|
| A. AGENCY: Massachusetts Dept. of Environmental Protection | B. APPLICATION TYPE: new construction | | |
| C. AGENCY CONTACT PERSON: Gary Roscoe | | D. PHONE NO.: 508-767-2773 | |
| E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: | P/C NO.: 118969 | ISSUANCE DATE: 4/16/1999 | |
| ☐ CHECK IF NO P/C | P/O NO.: 118969 | ISSUANCE DATE: 3/16/2001 | |
| F. START-UP DATE: March 2001 | | | |

## 5. EMISSION INFORMATION

APP. NO.: 118969

### A. PERMIT

A1. PERMIT LIMIT: PPMVD@15%O2 (1-hr block avg.): NOx-2.0, CO-3.0, VOC-1.4 (as CH4), NH3-2.0 except during startups and shutdowns (will be conditioned later on lb-per-event basis). Higher limits (3.5 ppm) are allowed for NOx and VOC in steam-augmentation mode. Higher limits are allowed for CO and VOC at reduced loads: CO-4.0 at 75% load and 20 at 50% load, VOC-2.5 at 50% load. PM limits: 23.9, 19.1 and 14.6 lb/hr at 100%, 75% and 50% load, respectively. Max. sulfur in fuel 0.8 grn/100 cu. ft. Facility-wide TPY limits (12-mo. rolling avg.): NOx-151, CO-437, VOC-49, NH3-47, PM-209, SO2-40, H2SO4-21.

A2. BACT/LAER DETERMINATION: PPMVD@15%O2 (1-hr block avg.): NOx-2.0, CO-3.0, VOC-1.4 (as CH4), NH3-2.0 except during startups and shutdowns. Higher limits allowed for NOx and VOC in steam-augmentation mode and for CO and VOC at reduced loads.

A3. BASIS OF THE BACT/LAER DETERMINATION: Emission limits were negotiated with the applicant.

### B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Engelhard (oxidation catalyst), Mitsubishi/Cormetech (SCR)

B2. TYPE: Oxidation catalyst and SCR

B3. DESCRIPTION:

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 118969 ISSUANCE DATE: 4/16/1999
P/O NO.: 118969 ISSUANCE DATE: 3/16/2001

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY: The plant is guaranteed to meet the permit limits.

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, PM, SOx

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY: Oxidation catalyst and SCR have operated well since startup. As of September 30, 2002, both units had over 5,000 hours operation.

B13. UNUSED B14. UNUSED

### C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (NA) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (NA) SOURCE OF COST DATA:

### D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION:

D3. VARIANCE: NO. OF VARIANCES: DATES:
CAUSES:

## 5. EMISSION INFORMATION

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D4. VIOLATION: NO. OF VIOLATIONS: DATES:

CAUSES:

D5. MAINTENANCE REQUIREMENTS:

D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:

DATE OF SOURCE TEST: June 5-7, July 5-12 and Dec 5-6, 2001; Feb 11-12 and May 15 2002

CAPTURE EFFICIENCY:

DESTRUCTION EFFICIENCY:

OVERALL EFFICIENCY:

SOURCE TEST/PERFORMANCE DATA: PPMVD@15%O2 (VOC as CH4):

| Unit | Date | Load | NOx | CO | VOC | NH3 |
|---|---|---|---|---|---|---|
| 1 | June | 75% | 1.6 | <0.1 | 0.2 | .06 |
| 1 | June | 50% | 1.4 | 0.5 | 0.2 | .08 |
| 2 | July | 75% | 1.5 | <0.1 | 0.4 | .02 |
| 2 | July | 50% | 1.7 | 0.8 | 0.4 | 0.2 |
| 2 | Dec | 87% | 1.4 | <0.1 | <0.1 | .05 |
| 1 | Feb | 87% | 1.7 | 0.3 | 0.1 | 0.1 |
| 1 | May | 87% | 1.6 | 0.3 | 0.1 | 0.1 |
| 2 | May | 87% | 1.6 | 0.0 | 0.1 | 0.1 |

OPERATING CONDITIONS: Steady

TEST METHODS: Test protocol was approved and all tests were formally accepted by Massachusetts DEP. In the July 50%-load test on Unit 2, PM exceeded the limit (19.2 versus 14.6 lb/hr limit). Unit 2 was re-tested at 50% load in December 2001 for PM only, and was well below the limit.

## 6. COMMENTS

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A NOx monitor on the turbine exhaust indicates that the ABB GT-24 gas turbine operates with NOx mostly in the 11-15 ppmvd range (corrected to 15%O2). Gas turbines with similar low NOx emissions may not be available in smaller sizes needed by some users, and it may be impractical to control NOx to 2.0 ppm on gas turbines with higher NOx levels. These smaller turbines may rely on water or steam injection for NOx control, and control of CO emissions to 3.0 ppmvd may be difficult on these turbines.

Results of certified CEMS (as posted on USEPA Acid Rain web site) for the first three quarters in 2002 show NOx in compliance with the 2.0 ppm limit with very few exceptions during over 2300 hours operation of Unit 1 and over 3700 hours operation of Unit 2. More exceedances were observed during the first year of operation (2001--1201 hours on Unit 1 and 1463 hours on Unit 2).

This plant has unfired HRSGs. The 3.0 ppmvd (corrected to 15% O2) CO limit at full load may be more difficult to meet on a plant that employs duct burners.

# Attachment B

**BEFORE THE ADMINISTRATOR**
**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

**In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), entitled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program"**

## AMENDED PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the undersigned organizations petition the Administrator of the Environmental Protection Agency ("the Administrator" or "EPA") to reconsider the final action referenced above. This final action constitutes a *de facto* final rule because it purports to establish binding requirements under the Clean Air Act's Prevention of Significant Deterioration ("PSD") program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Because EPA did not conduct a proper rulemaking proceeding prior to implementing this final action, as required by Section 307(d), Petitioners had no opportunity to raise objections to it through public comment. The objections raised in this petition are of central relevance to the outcome of the final action because they demonstrate that the action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). With respect to each objection, moreover, the regulatory language and EPA interpretations that render the rule arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law appeared for the first time in the final action published on December 31, 2008, 73 Fed. Reg. 80300. The Administrator must therefore "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." 42 U.S.C. § 7607(d)(7)(B).

The original Petition for Reconsideration was served on EPA on December 31, 2008. This Amended Petition differs from the original only in that it requests, in Section III, below, that EPA stay the effect of this agency action during the pendency of this

Petition for Reconsideration and during any challenge to this action filed in the U.S. Court of Appeals for the District of Columbia Circuit.

## INTRODUCTION

On December 18, 2008, EPA issued a document that purports to establish binding requirements under the Clean Air Act's PSD program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Memorandum from Stephen L. Johnson, *EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program* (December 18, 2008) (the "Johnson Memo" or "Memo"). EPA published notification of the Johnson Memo in the Federal Register on December 31, 2008. 73 Fed. Reg. 80300.

As discussed below, this final agency action was impermissible as a matter of law, because it was issued in violation of the procedural requirements of the Administrative Procedures Act ("APA"), 5 U.S.C. § 101 et seq., and the Clean Air Act ("CAA"), 42 U.S.C. § 7607, it directly conflicts with prior agency actions and interpretations, and it purports to establish an interpretation of the Act that conflicts with the plain language of the statute. Accordingly, the undersigned organizations request that EPA immediately reconsider and retract the Johnson Memo.

## BACKGROUND

In 2007, EPA Region 8 issued a PSD permit for a proposed new 110 MW unit at Deseret Power Electric Cooperative's existing Bonanza coal-fired power plant in Utah. Although Section 165 of the Act requires Best Available Control Technology ("BACT") for "each pollutant subject to regulation under this Act," and although $CO_2$ is regulated under the Act, the permit contained no BACT limits for $CO_2$.

In response to comments filed by Sierra Club, EPA contended for the first time in issuing the permit that it was precluded from requiring BACT limits for $CO_2$ based on a "longstanding interpretation" of the CAA that limited pollutants "subject to regulation" to those subject to actual control of emissions, as opposed to the $CO_2$ monitoring and reporting regulations in Subchapter C of Title 40 of the CFR. Sierra Club appealed the final permit to EPA's Environmental Appeals Board ("EAB" or "Board").[1]

The EAB rejected EPA's theory, vacated the permit and remanded it to Region 8: "[W]e conclude that the Region's rationale for not imposing a $CO_2$ BACT limit in the Permit – that it lacked authority to do so because of an historical Agency interpretation of the phrase 'subject to regulation under the Act' as meaning 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant' – is not supported by the administrative record." *In re Deseret Power Electric Cooperative*, PSD Appeal 07-03, slip op. at 63 (EAB Nov. 13, 2008), 13 E.A.D. __ *("Bonanza")*. To the contrary, the Board found that the **only** relevant interpretation of the applicable statutory and regulatory language was to be found in EPA's 1978 PSD rulemaking. That interpretation directly contradicted EPA's theory, and in fact "augurs in favor of a finding" that "subject to regulation under this Act" encompasses any pollutant covered by a regulation in Subchapter C of Title 40 of the CFR, such as $CO_2$. *Bonanza* at 41.

In addition, the Board also required an additional public notice and comment process addressing the question of $CO_2$ BACT limits for the Bonanza facility: "On remand, the Region shall reconsider whether or not to impose a $CO_2$ BACT limit in the Permit. In doing so, *the Region shall develop an adequate record for its decision, including reopening the record for public comment.*" *Id.* at 64 (emphasis added).

Due to the importance of the issue, the EAB suggested that EPA might want to undertake a proceeding of national scope to deal more broadly with the question of how to address $CO_2$ in the context of PSD permitting. Regardless of the chosen procedural

[1] The EAB has exclusive jurisdiction within EPA to review PSD permit decisions. 40 C.F.R. § 124.2(a) ("The Administrator delegates authority to the Environmental Appeals Board to issue final decisions in RCRA, PSD, UIC, or NPDES permit appeals filed under this subpart, including informal appeals of denials of requests for modification, revocation and reissuance, or termination of permits under Section 124.5(b). An appeal directed to the Administrator, rather than to the Environmental Appeals Board, will not be considered.").

mechanism, however, the Board was clear that additional notice and comment proceedings were necessary before EPA could adopt changes to the PSD program.

EPA responded to *Bonanza* by issuing the Johnson Memo, which states, "As of the date of this memorandum, EPA will interpret this definition of 'regulated NSR pollutant' to exclude pollutants for which EPA regulations only require monitoring or reporting but to include each pollutant subject to either a provision of the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. EPA published a notice in the Federal Register on December 31, 2008, stating that the Johnson Memo "contains EPA's 'definitive interpretation' of 'regulated NSR pollutant.'" 73 Fed. Reg. 80300.

## OBJECTIONS

### I. BECAUSE THE JOHNSON MEMO IS NOT AN "INTERPRETIVE RULE," ITS ISSUANCE VIOLATES PROCEDURAL REQUIREMENTS THAT MANDATES AGENCY RECONSIDERATION

The Johnson Memo purports to be "establishing an interpretation clarifying the scope of the EPA regulation that determines the pollutants subject to" the PSD program. Johnson Memo at 1. Whatever else the Johnson Memo is, it is definitely not an "interpretive rule." As the D.C. Circuit has explained:

> Interpretative rules "simply state[ ] what the administrative agency thinks the statute means, and only *remind[ ] affected parties of existing duties*." *General Motors Corp. v. Ruckelshaus,* 742 F.2d 1561, 1565 (D.C. Cir. 1984) (en banc) (internal quotation marks omitted). Interpretative rules may also construe substantive *regulations*. *See Syncor Internat'l Corp. v. Shalala,* 127 F.3d 90, 94 (D.C. Cir. 1997).

*Assoc. of Amer. RR v. Dept. of Transp.*, 198 F.3d 944 at 947 (D.C. Cir. 1999) (emphasis added). It is clear that EPA has so characterized it solely to avoid the procedural requirements – most importantly, public notice and comment – that would otherwise be imposed by the Clean Air Act, the Administrative Procedures Act, and the *Bonanza* decision. The Johnson Memo is a substantive rule, and not an interpretive one, because it reverses a formal agency interpretation, overturns an EAB decision, and amends the substance of the PSD program.

A. <u>The Johnson Memo Reverses a Formal Agency Interpretation</u>

In 1978, EPA determined in a Federal Register preamble that the phrase "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). This earlier interpretation – which has never been withdrawn or modified – directly conflicts with the interpretation the Memo purports to adopt. As discussed more fully below (pp. 8 *et seq.*), because the Subchapter C regulations include, *inter alia*, regulations that require monitoring and reporting of $CO_2$ emissions, the EAB held that this language offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. The logical implication of the 1978 Preamble is that BACT applies to $CO_2$ emissions. At a minimum, the 1978 Preamble accords agency permitting offices discretion under the Act and under EPA's regulations (which merely parrot the language of the Act) to require $CO_2$ BACT limits in PSD permits. Either way, the Johnson Memo impermissibly seeks to change that interpretation so as to *preclude* consideration of $CO_2$, thereby significantly modifying the nature and scope of the PSD program without notice and comment rulemaking.

The D.C. Circuit has held that when an agency's purported interpretation of a statute or regulation "constitutes a fundamental modification of its previous interpretation," the agency "cannot switch its position" without following appropriate procedures. *Paralyzed Veterans of Am. v. D.C. Arena L.P.,* 117 F.3d 579, 586 (D.C. Cir. 1997). Once an agency provides an interpretation of a statute – as EPA did here, in 1978 – "it can only change that interpretation as it would formally modify the regulation itself: through the process of notice and comment rulemaking." *Id.*

In an effort to bypass the procedures required by *Paralyzed Veterans*, the Memo claims that it is not actually refuting the 1978 Preamble's interpretation. It suggests, first, that because the 1978 Preamble did not itself "amplify the meaning of the term 'regulated in,'" EPA remains free to insert a wholly new definition of that term. Johnson Memo at 19. The Agency may not, however, evade the procedures mandated by *Paralyzed Veterans* by disguising a revision of governing law as an interpretation of its previous interpretation. *Paralyzed Veterans*, 117 F.3d at 586 (refusing to allow revisions or modifications of agency interpretations without notice and comment).

Second, the Memo contends that "the 1978 statement referred to the language in the statute which said 'pollutant subject to regulation under this Act,'" while "the 2002 regulation I am interpreting here uses the phrase 'pollutant that otherwise is subject to regulation under the Act.'" Johnson Memo at 19. The latter phrase, however, is a component of the former, so that the Memo's interpretation of "pollutant[s] . . . otherwise . . . subject to regulation under the Act" necessarily limits its interpretation of "pollutant[s] subject to regulation under this Act." 40 C.F.R. § 52.21(b)(50)(iv).

B. <u>The Johnson Memo Overturns the EAB's *Bonanza* Decision</u>.

While the Johnson Memo states that it "is not intended to supersede the Board's decision," Johnson Memo at 2, that is exactly what it does, even though the Administrator has no jurisdiction to undo a statutory interpretation adopted in an EAB ruling or substitute his judgment for that of the Board. *See* 40 C.F.R. § 124.2(a). The Board held that to adopt a new interpretation of the PSD regulatory program, EPA *must* undertake a new notice and comment process. *Bonanza* at 64 ("On remand, the Region *shall* reconsider whether or not to impose a $CO_2$ BACT limit in the Permit. In doing so, the Region *shall* develop an adequate record for its decision, including reopening the record for public comment.") (emphasis added).

Thus, the EAB – the final agency decision-maker as to PSD permits – has already addressed whether a notice and comment process is required for EPA to change its position regarding the appropriate scope of analysis in PSD permits, and concluded that it is. Significantly, the Board also ruled that the existing record was inadequate to support the agency's attempted reinterpretation of the Act – directing the agency on remand to "develop an adequate record for its decision." *Id.*[2]

[2] The EAB also specifically *rejected* EPA's argument that its interpretation was supported by "historic practice," finding it insufficient to undo "the authority the Region admit[ed] it would otherwise have under the statute." *Bonanza* at 46. In its attempt to circumvent the Board's conclusion, the Memo appears to introduce new evidence that

While the Board suggested that "[t]he Region should consider whether interested persons, as well as the Agency, would be better served by the Agency addressing the interpretation of the phrase 'subject to regulation under this Act' in the context of an action of nationwide scope, rather than through this specific permitting proceeding," *id.*, the Board clearly anticipated a process involving public notice and comment. EPA simply can not excuse itself from its legal obligation to pursue additional notice and comment before finalizing a change to its PSD regulations merely by seeking to adopt its new interpretation of the Act through an "interpretive rule".

To the extent that the Johnson Memo attempts to rely on public participation in the specific adjudicatory proceeding regarding the Bonanza plant, or public participation in an advanced notice of proposed rulemaking ("ANPRM") (which broadly addressed the implications of any and all potential EPA regulatory actions regarding greenhouse gases, 73 Fed. Reg. 44353 (July 30, 2008)), such reliance is legally insufficient to cure the procedural failures of this illegal rulemaking. Among other things, the *Bonanza* proceeding addressed only a single facility, and the adjudicatory process associated with an individual permit proceeding cannot substitute for notice and comment on a legislative rule of broad national significance. Even the parties to that proceeding did not have the benefit of the agency's fully-developed litigation position until EPA filed its supplemental brief that the Board ordered after oral argument. As the Board's final order requiring notice and comment on remand clearly indicates, that proceeding did not provide sufficient public process to support a decision to omit a $CO_2$ BACT limit from that particular permit, much less serve as an adequate substitute for notice and comment on a rule of nationwide scope.

Similarly, in the ANPRM, EPA never indicated its intention to take imminent final action establishing new parameters for the PSD regulatory program. To the contrary, the ANPRM by its very nature was probing and exploratory, not a vehicle intended to result in a final and binding agency policy. Indeed, as the Administrator's preface to the ANPRM explained: "None of the views or alternatives raised in this notice represents

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has never been subject to scrutiny of any kind. Johnson Memo at 11 (referring to "the record of permits compiled to support this memorandum").

Agency decisions or policy recommendations. It is premature to do so." 73 Fed. Reg. at 44355. Moreover, neither the adjudicatory proceeding nor the ANPRM provided any notice of EPA's specific intent to reinterpret the agency's policy articulated in the 1978 preamble. Accordingly, these activities cannot serve to dispose of the agency's obligation to undertake notice and comment processes before adopting a final legislative rule amending the CAA's PSD program.

C. <u>The Johnson Memo Substantively Amends the PSD Program</u>

The Johnson Memo seeks to substantively amend EPA regulations to establish new legal rights, restrictions, and/or obligations under the Act's PSD program, without any associated notice and comment process. This 19-page memo also takes a large number of other regulatory steps, including establishing specific exceptions to this rule (*e.g.,* exempting pollutants that are subject to regulation under the Act through state implementation plans ("SIPs") (Johnson Memo at 15));[3] establishing Regional Office responsibilities with regard to future SIP submittals (*Id.* at 3 n.1); determining how pollutants will become subject to PSD permitting in the future on enactment of new congressionally-mandated emission limits (*Id.* at 6 n.5); imposing requirements that address when pollutants for which EPA has made a regulatory endangerment determination must be treated as PSD pollutants (*Id.* at 14); and defining when and how import restrictions will trigger PSD for a pollutant. The sheer breadth of issues addressed, regarding numerous and disparate regulatory programs, defies EPA's claim that this is a mere "interpretive rule."

Thus, EPA's action constitutes an unlawful rulemaking under the APA and the CAA. EPA's action in the Johnson Memo, according to its own terms, treats the conclusions in the Memo as binding on EPA itself, and on states implementing the federal PSD program through delegation agreements with EPA, and leads "private parties or . . . permitting authorities to believe that it will declare permits invalid unless

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[3] We note, as EPA points out, that it has adopted a similar approach in at least one other regulatory program, *see* Johnson Memo at 15-16 (regarding the treatment of ammonia as $PM_{2.5}$ precursors), but that it did so – as it should have here – by notice and comment rulemaking. *See* 70 Fed. Reg. 65984; 73 Fed. Reg. 28321.

they comply with [its] terms." *Appalachian Power Co. v. EPA,* 208 F.3d 1015, 1021 (D.C. Cir. 2000). The Johnson Memo states that its newly established substantive parameters governing EPA's regulatory program, which significantly modify the federal PSD program, represent the agency's "settled position." *Id.* at 1022. It "reads like a ukase." *Id.* at 1023. Finally, the Memo certainly creates and/or changes the "rights," "obligations," and scope of authority of various parties, including EPA itself, citizens, regulated entities, and possibly delegated State permitting authorities, and "commands," "requires," "orders," or "dictates" a particular regulatory approach that will affect the rights of parties in currently pending and future permitting actions. *Id.* at 1023; *see also General Elec. Co. v. EPA,* 290 F.3d 377, 380 (D.C. Cir. 2002) (EPA risk assessment document was a legislative rule, "because on its face it purports to bind both applicants and the Agency with the force of law").

In sum, the Johnson Memo is a new regulation that adopts a substantially new interpretation of the Act and seeks to implement that interpretation through uncodified substantive changes to the PSD regulatory program. The D.C. Circuit has made clear that agencies may not avoid the procedural requirements by this sort of subterfuge:

> Although [our] verbal formulations vary somewhat, their underlying principle is the same: ***fidelity to the rulemaking requirements of the APA bars courts from permitting agencies to avoid those requirements by calling a substantive regulatory change an interpretative rule.***

*U.S. Telecom Ass'n v. F.C.C.*, 400 F.3d 29, 35 (D.C. Cir. 2005) (emphasis added and citations omitted). Accordingly, EPA must withdraw the Johnson Memo, and proceed, if at all, through appropriate notice and comment procedures.

## II. THE POSITIONS ASSERTED IN THE JOHNSON MEMO ARE IMPERMISSIBLE UNDER THE CLEAN AIR ACT

The Johnson Memo purports to adopt a binding interpretation of a regulation that parrots the Clean Air Act phrase, "pollutant subject to regulation under this Act." That interpretation would "exclude pollutants for which EPA regulations only require monitoring or reporting but . . . include each pollutant subject to either a provision in the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. The Memo thus attempts to revive a definition that the EAB found was not supported by any prior EPA interpretation of the statute. The Memo misconstrues the plain language of the Act, adopts impermissible interpretations of existing regulations, and ignores the distinct purpose of the PSD program in a vain attempt to forestall $CO_2$ emissions limits. In so doing, the Memo runs contrary to the Clean Air Act's clear mandate and flouts the Supreme Court's direction to use the regulatory flexibility that Congress provided to address new threats, such as climate change. *Massachusetts v. EPA,* 127 S. Ct. 1438, 1462 (2007).

A. The Johnson Memo Ignores the Plain Language of the Clean Air Act Requiring BACT for $CO_2$ Emissions.

EPA must impose emissions limitations on $CO_2$ in PSD permits for new coal-fired power plants. Section 165(a)(4) of the Clean Air Act requires BACT "for each pollutant subject to regulation under this chapter emitted from . . . such facility." 42 U.S.C. § 7475(a)(4). As even EPA now acknowledges, $CO_2$ is a pollutant under the Clean Air Act. *Massachusetts* , 127 S. Ct. at 1462. It is emitted abundantly by coal-fired generators and is currently regulated under the Clean Air Act through the Delaware SIP, as well as under monitoring and reporting requirements established by Section 821 of the 1990 Clean Air Act Amendments and the $CO_2$ monitoring requirements established by Congress' 2008 Appropriations Act.[4]

1. The Delaware SIP

On April 29, 2008, EPA approved a State Implementation Plan revision submitted by the State of Delaware that establishes emissions limits for $CO_2$, effective May 29, 2008. AR 123.3, 12.3, 73 Fed. Reg. 23101. The SIP revision imposes such $CO_2$ limits on new and existing distributed generators. Delaware Department of Natural Resources and Environmental Control; Division of Air and Waste Management, Air Quality Management Section, Regulation No. 1144. AR 123.2, Ex. 12.2., § 3.0.

In EPA's proposed and final rulemaking notices, EPA stated that it was approving the SIP revision "under the Clean Air Act," 73 Fed. Reg. 11,845, and "in accordance

[4] To the extent the EAB declined to hold that the PSD provision requires use of BACT for $CO_2$ emissions, the undersigned disagree with the Board's decision in that case. *American Bar Ass'n v. F.T.C.*, 430 F.3d 457, 468 (D.C. Cir. 2005) (reviewing courts "owe the agency no deference on the existence of ambiguity").

with the Clean Air Act," 73 Fed. Reg. at 23,101. EPA's approval made these $CO_2$ control requirements part of the "applicable implementation plan" enforceable under the Act, 42 U.S.C. § 7602(q), and numerous provisions authorize EPA to so enforce these SIP requirements, *e.g.*, 42 U.S.C. § 7413 (authorizing EPA compliance orders, administrative penalties and civil actions). In addition, EPA's approval makes these emission standards and limitations enforceable by a citizen suit under Section 304 of the Act. 42 U.S.C. § 7604(a)(1), (f)(3).

The Delaware SIP Revision constitutes regulation of $CO_2$ under the Clean Air Act because it was adopted and approved under the Act and is part of an "applicable implementation plan" that may be enforced by the state, by EPA, and by citizens under the Clean Air Act. Thus $CO_2$ is a pollutant "subject to regulation" under the Act for BACT purposes, **even under the definition put forth in the Johnson Memo** because it is "subject to . . . [a] regulation adopted by EPA under the Clean Air Act that requires actual control of emissions." Johnson Memo at 1.

Nevertheless, in an effort to evade the consequences of the Delaware SIP, the Memo purports to create an exception specifically designed to exclude the SIP from its definition of "regulation under the Act." *Id.* at 15. As support for its novel (and incorrect) interpretation, the Memo purports to rely on *Connecticut v. EPA*, 656 F.2d 902 (2d Cir. 1981). It construes that case as holding that the "Congress did not allow individual states to set national regulations that impose those requirements on all other states." Johnson Memo at 15. But *Connecticut* does not support that conclusion; indeed, it has nothing to do with the issue here, namely whether a particular pollutant is "subject to regulation" under the Act. Clean Air Act § 165(a)(4). Rather, *Connecticut* discusses only whether the quantitative limits imposed by one state on a particular pollutant apply to neighboring states under the "good neighbor" provision in § 110. *See Connecticut*, 656 F.2d at 909 (Section "110(a)(2)(E)(i) is quite explicit in limiting interstate protection to federally-mandated pollution standards.") (emphasis added). *Connecticut* provides no support to the Johnson Memo's arbitrary limitation on the scope of what constitutes a regulation under the Act – and demonstrates that the Memo's interpretation is driven not by the language or purpose of the statute, but rather by the agency's intractable refusal to address $CO_2$ emissions.

Nothing illustrates this better than the Memo's conclusion that "EPA does not interpret section 52.21(b)(50) of the regulations to make CO2 'subject to regulation under the Act' for the nationwide PSD program based solely on the regulation of a pollutant by a single state in a SIP approved by EPA." Johnson Memo at 15. In other words, conceding that the Delaware SIP constitutes "regulation under the Act", the Memo takes the position that such regulation by a single state is not enough. Neither the Act nor its regulations provide a basis for this position – indeed, the Memo makes no attempt to provide a basis.

Thus the Johnson Memo replaces the simple statutory test of whether a pollutant is "subject to regulation under the Act" with a test of whether the pollutant is "subject to regulation under the Clean Air Act in a sufficient number of states or, alternatively, in the state (or Region) where the facility is to be constructed."[5] But that is not what the Act says, nor does the Memo offer any support for the contention that regulation of $CO_2$ in another part of the country does not count as "regulation." Under the plain language of Section 165(a)(4), if $CO_2$ emissions are restricted under the Clean Air Act, whether in one state or all 50, they are "subject to regulation under the Act" – even under the Memo's improperly narrow definition of "regulation."

Finally, SIP regulations appear in "Subchapter C of Title 40 of the Code of Federal Regulations." 43 Fed. Reg. at 26,397. *See, e.g.,* 40 C.F.R. § 52.420 (2008) (incorporating by reference provisions of Delaware SIP). They are, accordingly, within the scope of the Agency's governing 1978 interpretation, even if that interpretation meant to say "regulated by requiring actual control of emissions" when it said "regulated." If the EPA wished to exclude SIP-based regulations, it would be required to modify its current interpretation, and provide the public with notice and an opportunity to comment upon that modification. *See Paralyzed Veterans,* 117 F.3d at 586.[6]

[5] The Memo does not disclose how many states Administrator Johnson believes would suffice. Two? Three? Six? Fourteen?

[6] The EAB did not reach the issue of whether $CO_2$ is regulated under the Clean Air Act because it is regulated in the Delaware SIP, instead directing EPA to consider this issue "along with other potential avenues of regulation of $CO_2$." *Bonanza* at 55 n.57.

2. Section 821

In addition to being regulated under the Delaware SIP, $CO_2$ is regulated under Section 821 of the Clean Air Act Amendments of 1990. Section 821 requires EPA to "promulgate regulations" requiring major sources, including coal-fired power plants, to monitor carbon dioxide emissions and report their monitoring data to EPA:

> The Administrator of the Environmental Protection Agency *shall promulgate regulations* within 18 months after the enactment of the Clean Air Act Amendments of 1990 *to require that all affected sources subject to Title [IV] of the Clean Air Act shall also monitor carbon dioxide emissions* according to the same timetable as in Sections [412](b) and (c). *The regulations shall require that such data be reported to the Administrator.* The provisions of Section [412](e) of title [IV] of the Clean Air Act shall apply for purposes of this Section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 412.

42 U.S.C. § 7651k note; Pub. L. 101-549; 104 Stat. 2699 (emphasis added). In 1993, EPA promulgated these regulations, which require sources to monitor $CO_2$ emissions, 40 C.F.R. §§ 75.1(b), 75.10(a)(3), prepare and maintain monitoring plans, *id.* § 75.33, maintain records, *id.* § 75.57, and report monitoring data to EPA, *id.* § 75.60-64. The regulations prohibit operation in violation of these requirements and provide that a violation of any Part 75 requirement is a violation of the Act. *Id.* § 75.5. Not only do the regulations require that polluting facilities "measure . . . $CO_2$ emissions for each affected unit," *id.* § 75.10(a), they also prohibit operation of such units "so as to discharge or allow to be discharged, emissions of . . . $CO_2$ to the atmosphere without accounting for all such emissions . . . . " *Id.* § 75.5(d).

In *Bonanza*, EPA argued that monitoring regulations are not actually regulation and that Section 821 did not actually amend the Clean Air Act. The EAB having rejected EPA's attempt to banish Section 821 from the Act, the Johnson Memo now depends solely on the flawed argument that regulation requiring monitoring and reporting is not regulation. On the contrary, monitoring and reporting requirements clearly constitute regulation. Against the backdrop of Section 165's use of "regulation," Congress explicitly used that exact same word in Section 821 to refer solely to monitoring and reporting requirements. Just like regulations restricting emissions quantities, the regulations EPA promulgated implementing Section 821 have the force of law, and violation results in severe sanctions. 40 C.F.R. § 75.5; 42 U.S.C. § 7413(c)(2) (punishable by imprisonment of up to six months or fine of up to $10,000 for making false statement or representation or providing inaccurate monitoring reports under Clean Air Act).[7] Indeed, as the Region and OAR admitted in the supplemental brief (and exhibits) they filed with the EAB in *Bonanza*, EPA has enforced section 821 in a number of consent decrees that require the installation of $CO_2$ monitoring equipment.

In support of the interpretation of "regulation" to mean only a restriction on emissions quantity, the Johnson Memo recites the assorted dictionary definitions of "regulation" from the *Bonanza* briefing without any discussion of Section 821 and its use of this exact same word. Nor does the Memo appear to recognize that each of those definitions would include monitoring. Its preferred definition – "the act or process of controlling by rule or restriction" – encompasses regulations to monitor emissions just as easily as regulations that limit emissions quantities. Pursuant to Section 821, $CO_2$ is "controlled" by a "rule or restriction" because EPA's regulations require that emissions be monitored, which cannot be done if those emissions are freely emitted; by definition, monitoring requires that the flow of emissions be controlled. Indeed, monitoring creates more direct control over emissions of a pollutant than import restrictions, which involve only indirect control over emissions. Moreover, "control" is not synonymous with "cap" or "limit." The Memo clearly recognizes that distinction because it repeatedly supplements the original language of its interpretation ("actual control of emissions") by adding "limitation" ("actual control or limitation of emissions"). *See, e.g.,* Johnson Memo at 8. Finally, *Black's* defines "control" as "the power or authority to manage, direct, or

[7] In addition to the monitoring requirements imposed by Section 821, Congress has specifically required monitoring of all greenhouse gases, including $CO_2$, economy-wide, in the 2008 Consolidated Appropriations Act. H.R. 2764; Public Law 110-161, at 285 (enacted Dec. 26, 2007). As a result, $CO_2$ monitoring and reporting is required under the Act separate and apart from Section 821. The Johnson Memo attempts to evade the consequences of the Appropriations Act requirement by, among other things, opining that a pollutant is not "subject to regulation" when Congress specifically tells EPA to regulate it, but only when EPA actually adopts regulations. Johnson Memo at 14. The deadline has passed for EPA to issue the proposed regulations required by the Appropriations Act with no action by EPA.

oversee." *Black's Law Dictionary* (8th ed. 2004). Monitoring and reporting regulations certainly constitute oversight.

The Johnson Memo serves to confuse rather than clarify the definition of regulation. EPA should withdraw it and comply with the plain language of the Act, which requires BACT limits for pollutants subject to monitoring and reporting regulations.

B. The Interpretation in the Johnson Memo is Inconsistent with the Only Relevant Regulatory History.

1. The 1978 Preamble

The Johnson Memo repudiates the only Agency interpretation of the words "subject to regulation under this Act" that the EAB identified as "possess[ing] the hallmarks of an Agency interpretation that courts would find worthy of deference" – the preamble to the Agency's 1978 Federal Register rulemaking, 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). *Bonanza* at 39. In the 1978 Federal Register preamble, the Administrator established that "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. at 26,397. As the Board recognized, that preamble offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. Instead (again, as expressly noted by the Board) it implies that "$CO_2$ became subject to regulation under the Act in 1993 when the Agency included provisions relating to $CO_2$ in Subchapter C." *Id.* at 42 n.43.

Under the 1978 preamble definition, $CO_2$ is "subject to regulation" for BACT purposes because it is regulated under Subchapter C of Title 40 of the Code of Federal Regulations. In its 1993 rulemaking to revise the PSD regulations, EPA did not withdraw its 1978 interpretation of "subject to regulation." *See Bonanza* at 42; *see also* Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals, 58 Fed. Reg. 3,590, 3,701 (Jan. 11, 1993) (final rule implementing § 821's $CO_2$ monitoring and reporting regulations). Nor has any subsequent rulemaking, including the 2002 rulemaking on which the Johnson Memo relies, disturbed the 1978 interpretation. *See*

*Bonanza* at 46. Thus, the only existing EPA interpretation of the phrase "subject to regulation" in Section 165(a)(4), 42 U.S.C. § 7465(a)(4), affirms that BACT is required for $CO_2$ emissions because it is regulated under the Act's implementing regulations.

The Johnson Memo seeks to change this interpretation. It purports to establish that henceforth, BACT will be required for "only those pollutants for which the Agency has established regulations requiring actual controls on emissions," Johnson Memo at 12 precisely the interpretation to which, according to the Board, "the 1978 Federal Register preamble *does not lend support.*" *Bonanza* at 41 (emphasis added).

EPA seeks to elide its amendment of the 1978 interpretation via two routes. First, it asserts that "the specific categories of regulations identified in the second sentence of the passage quoted above are all regulations that require control of pollutant emissions." Johnson Memo at 12. *Bonanza* directly refutes that claim: "Nothing in the 1978 preamble . . . indicates that the Agency intended to depart from the normal use of 'includes' as introducing an illustrative, and non-exclusive, list of pollutants subject to regulation under the Act." *Bonanza* at 40 (holding that "we must reject" the "conten[tion] that only the pollutants identified in the preamble by general category defined the scope of the Administrator's 1978 interpretation).

Second, the Memo claims that the phrase "regulated in" as it appears in the 1978 Preamble is ambiguous and thus subject to clarification by the Agency, such that the 1978 Preamble may be understood to mean "regulated by actual control of emissions" by use of the term "regulated." Johnson Memo at 12. ("[I]t is still not clear that a monitoring or reporting requirement added to subchapter C would make that pollutant 'regulated in' Subchapter C because of the alternative meanings of the term regulation, regulate, and regulated discussed earlier").

This newly proposed understanding of the words "regulated in" fits so unnaturally with the text of the 1978 Federal Register preamble as to defy credibility. That understanding would, entirely *sub silentio,* impose an enormously substantive and restrictive qualification by use of the words "regulated in," while dismissing the far more prominent reference to "Subchapter C of Title 40 of the Code of Federal Regulations" as irrelevant verbiage. Like Congress, agencies cannot be presumed to hide such "elephants in mouseholes." *Whitman v. American Trucking Ass'n*, 531 U.S. 457, 468 (2001). The words "regulated" and "regulation," appear pervasively throughout the 1978 Federal Register preamble, uniformly meaning (as they always do) *any* act of regulating or regulation. *See, e.g.*, 43 Fed. Reg. 26,389 ("The regulations made final today apply to any source . . ."), 26,398 ("In the regulations adopted today, EPA's assessment of the air quality impacts of new major sources and modifications will be based on" certain EPA guidelines), 26,401 ("Such offsets have always been acceptable under the agency's PSD regulations . . . ."), 26,402 ("Environmental groups pointed out that the proposed regulations did not specifically require Federal Land Managers to protect "affirmatively" air quality related values . . . .").

Those references demonstrate that the Agency in 1978 used "regulation" and "regulate" as they are generally used: to encompass all forms of regulation. In explaining the meaning of the phrase "subject to regulation," the Agency offered no hint that, merely by employing the words "regulated in," it was departing from that standard-English definition – much less that it was adopting the Johnson Memo's "alternative" definition. Under any plausible reading, the 1978 Federal Register preamble used "regulated in" to describe *all* the regulations contained "in Subchapter C of Title 40 of the Code of Federal Regulations." *See Bonanza* at 41-42 & n.43 (noting that "plain and more natural reading of the preamble's interpretative statement suggests a different unifying rule" than a rule that would limit "regulation" to actual control of emissions).[8]

The Johnson Memo's proposed interpretation of the term "subject to regulation" via the "regulated in" subterfuge is not only disingenuous, but absurd. The Memo claims that the Agency can freely substitute its new definition of "regulation" as "regulation requiring actual control of emissions" for the word "regulation" in whatever form the latter appears, apparently in any regulatory document. Johnson Memo at 11.

---

[8] Indeed, in *Bonanza* EPA assumed that the 1978 Preamble used the word "regulated" in this most natural sense, hence its reliance on the enumerated examples as limiting "the scope" of the reference to the Code of Federal Regulations, and its citation of the preamble to the 1993 rulemaking as reflecting an intent to avoid including $CO_2$ among the pollutants regulated under the Act. *Bonanza* at 41-42.

Nor, logically, does it stop there: not only "regulation", but also "regulate" and "regulated" are now up for grabs; they now mean anything Administrator Johnson wants them to mean, wherever they might appear in any environmental statute or EPA regulation.

2. The 2002 Regulation

The Johnson Memo attempts to narrow the plain language of the Clean Air Act and EPA's 1978 interpretation of that language by purporting to interpret a 2002 implementing regulation rather than the statute itself. That regulation states:

> *Regulated NSR pollutant,* for purposes of this section, means the following:
>
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and . . . any constituent[s] or precursors for such pollutant[s]. . . . identified by the Administrator [e.g., volatile organic compounds are precursors for ozone];
>
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;
>
> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; [or]
>
> (iv) **Any pollutant that otherwise is subject to regulation under the Act;** except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not be delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

40 C.F.R. § 52.21(b)(50) (emphasis added). The Memo declares that it is interpreting the phrase "any pollutant that otherwise is subject to regulation under the Act" in this definition when it excludes pollutants subject to monitoring regulations and pollutants regulated "solely . . . by a single state in a SIP approved by EPA." Johnson Memo at 15.

In reality, the Johnson Memo is interpreting the language of the statute. The agency's interpretation of its regulation is not entitled to deference because the regulation simply parrots the language of the statute.

> [T]he existence of a parroting regulation does not change the fact that the question here is . . . the meaning of the statute. An agency does not acquire special authority to interpret its own words when, instead of using its expertise and experience to formulate a regulation, it has elected merely to paraphrase the statutory language.

*Gonzales v. Oregon*, 546 U.S. 243, 257 (2006). Moreover, because the regulation merely paraphrases statutory language that EPA already interpreted in 1978, that earlier interpretation applies to the language of both the statute and rule absent an indication in the 2002 rulemaking that EPA was abandoning it; as EAB found, that rulemaking contained no such indication. *Bonanza* at 46. EPA cannot now change its prior interpretation in a memo issued with complete disregard for the public notice and comment that the law requires. *See* pp. 4-9, *supra*.

The Johnson Memo rationalizes its narrow interpretation by relying on a canon of statutory construction known as *ejusdem generis*, which provides that "where general words follow the enumeration of particular classes of things, the general words are most naturally construed as applying only to things of the same general class as those enumerated." *Am. Mining Cong. v. EPA*, 824 F.2d 1177, 1189 (D.C. Cir. 1987) (quoted in *Bonanza* at 45). It reasons that EPA can construe "otherwise subject to regulation" in subsection (iv) to apply to the same class of pollutants allegedly covered by subsections (i) – (iii) of the "regulated NSR pollutant" definition—those "pollutants subject to a promulgated regulation requiring actual control of a pollutant." Johnson Memo at 8.

Numerous defects undermine this reasoning. Most importantly, it directly conflicts with the *Bonanza* decision because the EAB explicitly held that it is not appropriate to use *ejusdem generis* to interpret a parroting regulation "[w]ithout a clear and sufficient supporting analysis or statement of intent *in the regulation's preamble*." *Bonanza* at 46 (emphasis added). The Memo attempts to remedy this omission by belatedly supplying "additional analysis and statement of intent regarding the regulation." Johnson Memo at 9. Analysis in a memo, however, is an inadequate substitute for the missing analysis in the rulemaking itself. The EAB held that the analysis should be in the preamble, and the failure to include it deprives the public of proper notice and the opportunity to comment.

Indeed, *ejusdem generis* is entirely inapplicable in this situation. The fundamental dispute here concerns the meaning of a broadly-worded provision of the Clean Air Act, not the nearly identical language of a subsection of the regulation. The Act does not contain a list; it contains a single broad category of pollutants "subject to regulation." The Supreme Court has cautioned against narrowly interpreting the broad language of the Clean Air Act. *Massachusetts*, 127 S.Ct. at 1462. EPA may not restrict that language through the back door by interpreting a parroting regulation with a narrowing canon of construction not suited to the statute itself.

Even looking at only the regulation, applying *ejusdem generis* is inappropriate because "the whole context dictates a different conclusion." *Norfolk & W. Ry. Co. v. Am. Train Dispatchers' Ass'n*, 499 U.S. 117, 129 (1991). The first three subsections of the regulation refer to pollutants subject to a "standard" that has been promulgated, while the fourth covers "[a]ny pollutant that is *otherwise* subject to *regulation* under the Act." 40 C.F.R. 52.21(b)(50) (emphasis added). The use of "otherwise" and "regulation" indicates that it applies to pollutants regulated in some other way than by a standard. Moreover, subsections (i) through (iii) are not so alike, since subsection (i) refers to ambient air quality standards that in and of themselves do not require control of emissions, (ii) refers to standards governing emissions from sources, and (iii) refers to standards that only indirectly control emissions. Tellingly, the "general class" that the Johnson Memo identifies ("pollutants that are subject to a promulgated regulation requiring actual control of a *pollutant*") differs from the other iterations of the interpretation (pollutants subject to a regulation "that requires actual control of *emissions* of that pollutant)," in a way evidently designed to minimize the differences among the three pollutant categories enumerated. Memo at 8, 1 (emphasis added).

C. The Johnson Memo Contravenes the Purpose and Structure of the Clean <u>Air Act By Prohibiting BACT for $CO_2$ Emissions</u>.

Limiting BACT as described in the Johnson Memo ignores the broad, protective purpose of the PSD program. Congress explicitly stated that the purpose of the PSD program was to "protect public health and welfare from **any** actual or **potential adverse effect** which in the Administrator's judgment may reasonably be anticipate[d] to occur from air pollution . . . notwithstanding attainment and maintenance of all national ambient air quality standards." 42 U.S.C. § 7470(1) (emphasis added). In stark contrast, Congress required EPA to make an endangerment finding before establishing generally applicable standards such as the NAAQS, New Source Performance Standards, or motor vehicle emissions standards. Each of these programs expressly require EPA to find that emissions of a pollutant "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare" as a prerequisite to regulation. *Id.* § 7408(a)(1)(A); *id.* § 7521(a)(1); *see also id.* § 7411(b)(1).

In the PSD program, Congress used language showing that it clearly intended that BACT apply regardless of whether an endangerment finding had been made for that pollutant. Thus Congress – which was quite familiar with the "endangerment trigger" – deliberately established a much lower threshold for requiring BACT than an "endangerment finding." Thus requiring BACT for "each pollutant subject to regulation under the Act" meshes perfectly with the purpose of the PSD program to guard against any "potential adverse effect" as opposed to "endangerment of public health or welfare." And because the BACT analysis entails a case-by-case inquiry, it is more dynamic in assimilating new information than other statutory standards, such as New Source Performance Standards.

As the Johnson Memo's focus on endangerment demonstrates, *see, e.g.*, Johnson Memo at 18, the interpretation it adopts improperly limits the scope of the PSD program and the BACT requirement. It ignores the broader purpose of the PSD program by limiting the BACT requirement to pollutants already subject to limitations on emissions. *Id.* at 13. Strangely, it attempts to justify this interpretation by stating: "The fact that Congress specified in the Act that BACT could be no less stringent than NSPS and other control requirements under the Act indicates that Congress expected BACT to apply to pollutants controlled under these programs." *Id.* But, quite obviously, the fact that BACT *applies* to pollutants controlled under those programs does not mean that it is *limited* to them. Instead, the congressional directive that BACT be no less stringent than those other control requirements is a further indication that BACT is meant to be ***more*** protective and apply more broadly. The Johnson Memo demonstrates a fundamental misperception of the role of the PSD program and its BACT requirement within the Act.

D. The Need to Study Pollutants Does Not Justify Prohibiting BACT for $CO_2$.

The Johnson Memo defends the decision to prohibit BACT limits for $CO_2$ by asserting that it would "frustrate the Agency's ability to gather information using Section 114 and other authority and make informed and reasoned judgments about the need to establish controls or limitations on individual pollutants." *Id.* at 9. This rationale is nothing but a red herring. Throughout the *Bonanza* proceeding, EPA has not identified a single pollutant other than $CO_2$ that would be affected by an interpretation of "regulation" in Section165 to include monitoring and reporting regulations. EPA is free to gather information about pollutants under Section 114 without adopting regulations. And Congress explicitly singled out $CO_2$ as a pollutant of special concern in Section 821. Nothing in that provision indicates that Congress intended $CO_2$ to be considered regulated under the Act for some purposes but not for other purposes. If Congress directs EPA to adopt monitoring regulations under the CAA for particular pollutants, it can choose to expressly exclude those pollutants from BACT requirements, but it did not do so in Section 821.

The Johnson Memo opines that "[t]he current concerns over global climate change should not drive EPA into adopting an unworkable policy of requiring emissions controls under the PSD program any time that EPA promulgates a rule under the Act that requires a source to gather or report emissions data under the Act for any pollutant." *Id.* at 10. But EPA has not demonstrated that anything is unworkable about requiring BACT for pollutants subject to monitoring regulations when Congress has expressly singled out specific pollutants for regulation without excluding them from BACT. And it has not demonstrated that BACT would be required in any other situation. EPA has pointed to nothing in the Act that supports its position that requiring BACT for pollutants subject to monitoring conflicts with Congress' information-gathering objectives under the Act. *See Massachusetts,* 127 S.Ct. at 1460-61 ("And unlike EPA, we have no difficulty reconciling Congress' various efforts to promote . . . research to better understand climate change with the agency's pre-existing mandate to regulate 'any air pollutant' that may endanger the public welfare.") (footnote and citation omitted). As the Supreme Court has held, EPA cannot ignore its duties under the Clean Air Act to address pollutants that cause global climate change, and the statute offers the regulatory flexibility needed to do so. *Id.* at 1462.

The plain language of the Clean Air Act, its structure, and authoritative regulatory history of the phrase, "subject to regulation under this Chapter" all support the conclusion that BACT is required for *each* pollutant subject to any sort of regulation under the Act. The EAB has held that EPA has never established a contrary position in any action entitled to deference, and it may not now do so in an internal agency memorandum.

## III. EPA SHOULD STAY THE EFFECT OF THE JOHNSON MEMO

By its own terms, the Johnson Memo purports to go into effect "immediately." Johnson Memo at 2. Because the Memo so clearly violates both the procedural requirements of the Administrative Procedure Act, the Clean Air Act, and the *Bonanza* decision, as well as the substantive requirements of the Clean Air Act, EPA should stay implementation of the Memo during the pendency of this Petition for Reconsideration and during the pendency of any challenge to the Memo in the U.S. Court of Appeals for the District of Columbia Circuit.

## CONCLUSION

EPA must reconsider its final action for all of the reasons stated above.

DATED: January 6, 2009

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# Attachment C

## Weyman Lee

**From:** Brian Lusher
**Sent:** Wednesday, September 10, 2008 3:19 PM
**To:** Weyman Lee
**Subject:** Fast start up text

The District has been closely following the recent development of new technologies that will allow facilities to reduce their startup times. The District is aware of the software and other operation modifications that have the potential to achieve significant emissions reductions, although it should be noted that at this stage these modifications have only limited operational experience. In addition, some designs utilize an additional source such as an auxiliary boiler which has additional emissions associated with it that would offset the reductions from the shortened startup times. It should be noted that most of the reduced startup time technologies require some new hardware and retrofit packages are not commercially available at this time.

The District has reviewed information about some of the reduced startup time gas turbine/HRSG designs and would note that these designs offer reduced startup times and reduced startup emissions. However, most of these designs are not as efficient as a base load design combined cycle turbine/HRSG plant such as Gateway. The March 2001 Final Staff Assessment for the project has the plant efficiency at 54.1% on a Lower Heating Value basis. The District has reviewed some of the new reduced startup designs that are intermediate peaking designs and these plants have an efficiency just below 50% on a Lower Heating Value basis.

The Gateway project was originally permitted in 2001, however, and at the time such these technologies had not yet been developed. As a result, they were not included in the design and permitting of the project. Moreover, the project owner purchased the combustion turbines and steam turbine generator at that time. Requiring the project to incorporate such technologies at this stage would necessitate a complete redesign of the project and the purchase of new equipment. It would therefore not technologically feasible to implement these reduced start time technologies for the Gateway project at this time.



[redacted]

# Attachment D

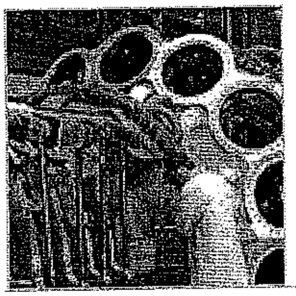
GE
Energy

WORLDWI



# H System™ Combined Cycle Gas Turbine





**60 Percent Fuel Efficiency**

GE's H System – an advanced combined cycle system capab breaking the 60 percent efficiency barrier – integrates the gas steam turbine and heat recovery steam generator into a seam system, optimizing each component's performance. Undoubte leading technology for both 50 and 60 Hz applications, the H ( higher efficiency and output to reduce the cost of electricity of fired power generation system.

## Features & Benefits

**Closed-Loop Steam Cooling**

Open loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. This closed-loop steam cooling enables the H System to achieve 60 percent fuel efficiency at rated conditions while adhering to the strictest low nitrogen oxide standards and reducing carbon dioxide emissions. Additionally, closed-loop cooling also minimizes parasitic extraction of compressor discharge air, thereby allowing more air to flow to the combustor for fuel premixing.

**Single Crystal Materials**

The use of these advanced materials on the first stage nozzles and buckets, and thermal barrier coatings on the first and second stage nozzles and buckets, ensures these components stand up to high firing temperatures while meeting maintenance intervals.

**Dry Low NOx Combustors**

Building on GE's design experience, the H System employs a can-annular lean pre-mix DLN-2.5 Dry Low NOx (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NOx levels in several million hours of field service around the world. The H System DLN 2.5 combustion system wil have increased fuel flexibility, while maintaining the capability to achieve low NOx between 50 and 100% load.

**Small Footprint/High Power Density**

The H System offers improved power density per installed megawatt compared to other combined cycle systems, once

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Power Systems for the 2' Century: "H" Gas Turbine Combined Cycles (252KE

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## News Archive

Dec 11, 2007 GE's H Sys Gas Turbine Hits Project Milestone In Japan

Sep 10, 2007 GE'S First Hertz H System* Gas Tui Project Moves Toward Commercial Startup Next again helping to reduce the overall cost of producing electricity.

**Thoroughly Tested**

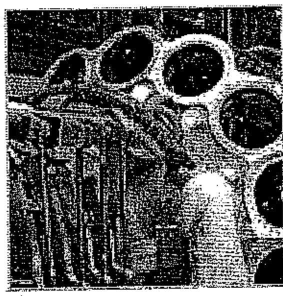
The design, development and validation of the H System has been conducted under a regimen of extensive component, sub-system and full unit testing. Broad commercial introduction has been controlled to follow launch units demonstration. This thorough testing approach provides the introduction of cutting edge technology with high customer confidence. The first H System located at Baglan Bay, Wales has been in commercial operation since September 2003 and has achieved significant operating experience.

Learn more about the H System launch site, Baglan Bay

| Combined Cycle Performance at Rated Conditions | 60 Hz (S107H) | 50 Hz (S 109H) |
|---|---|---|
| Plant Output | 400 MW | 520 MW |
| Heat Rate | 5,690 Btu/kWh (6,000 kj/kWh) | 5,690 Btu/kWh (6,000 kj/kWh) |
| Net Plant Efficiency | 60 Percent | 60 Percent |
| Gas Turbine Number and Type | 1x MS7001H | 1x MS9001H |

# H System™ Combined Cycle Gas Turbine

Home
Products & Services
Products
Gas Turbines - Heavy Duty
H System™ Combined Cycle Gas Turbine
F Class
Medium Size Gas Turbines
Small Heavy Duty
Combined Cycle
IGCC
Services
Lifecycle Services



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## Features & Benefits

**Closed-Loop Steam Cooling**

Open loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. This closed-loop steam cooling enables the H System to achieve 60 percent fuel efficiency at rated conditions while adhering to the strictest low nitrogen oxide standards and reducing carbon dioxide emissions. Additionally, closed-loop cooling also minimizes parasitic extraction of compressor discharge air, thereby allowing more air to flow to the combustor for fuel premixing.

**Single Crystal Materials**

The use of these advanced materials on the first stage nozzles and buckets, and thermal barrier coatings on the first and second stage nozzles and buckets, ensures these components stand up to high firing temperatures while meeting maintenance intervals.

**Dry Low NOx Combustors**

Building on GE's design experience, the H System employs a can-annular lean pre-mix DLN-2.5 Dry Low NOx (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NOx levels in several million hours of field service around the world. The H System DLN 2.5 combustion system wil have increased fuel flexibility, while maintaining the capability to achieve low NOx between 50 and 100% load.

**Small Footprint/High Power Density**

The H System offers improved power density per installed megawatt compared to other combined cycle systems, once

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H System: The World's M Advanced Combined Cyc Technology Brochure (98 PDF)

Power Systems for the 2' Century: "H" Gas Turbine Combined Cycles (252KE

MPG Video: H System: V Most Advanced Combine Gas Turbine (19MB ZIP)

H System™- Rasiing the large combined cycle (23 PDF)

**News Archive**

Dec 11, 2007 GE's H Sys Gas Turbine Hits Project Milestone In Japan

Sep 10, 2007 GE'S First Hertz H System* Gas Tu Project Moves Toward Commercial Startup Next again helping to reduce the overall cost of producing electricity.

**Thoroughly Tested**
The design, development and validation of the H System has been conducted under a regimen of extensive component, sub-system and full unit testing. Broad commercial introduction has been controlled to follow launch units demonstration. This thorough testing approach provides the introduction of cutting edge technology with high customer confidence. The first H System located at Baglan Bay, Wales has been in commercial operation since September 2003 and has achieved significant operating experience.

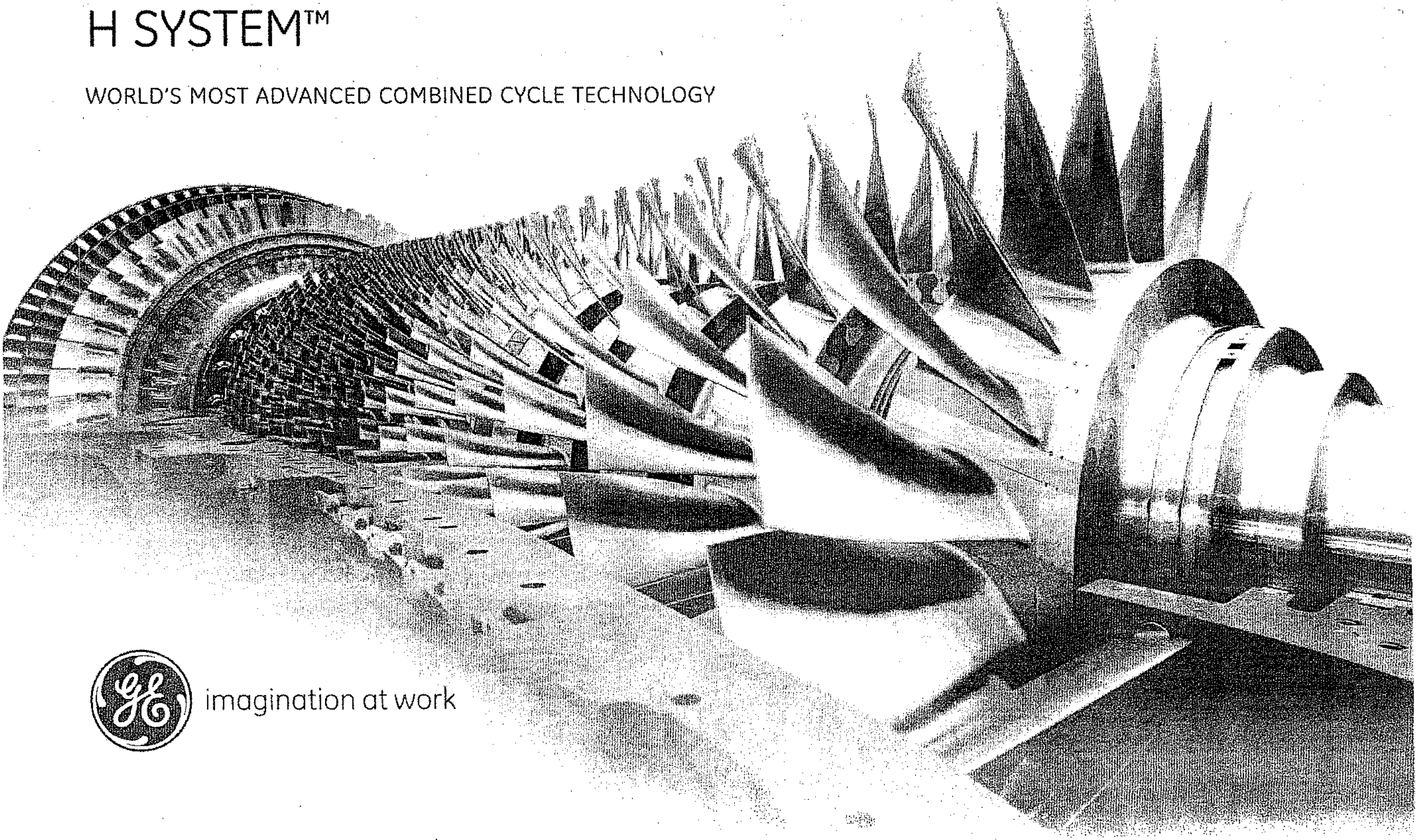
Learn more about the H System launch site, Baglan Bay

| Combined Cycle Performance at Rated Conditions | 60 Hz (S107H) | 50 Hz (S 109H) |
|---|---|---|
| Plant Output | 400 MW | 520 MW |
| Heat Rate | 5,690 Btu/kWh (6,000 kj/kWh) | 5,690 Btu/kWh (6,000 kj/kWh) |
| Net Plant Efficiency | 60 Percent | 60 Percent |
| Gas Turbine Number and Type | 1x MS7001H | 1x MS9001H |

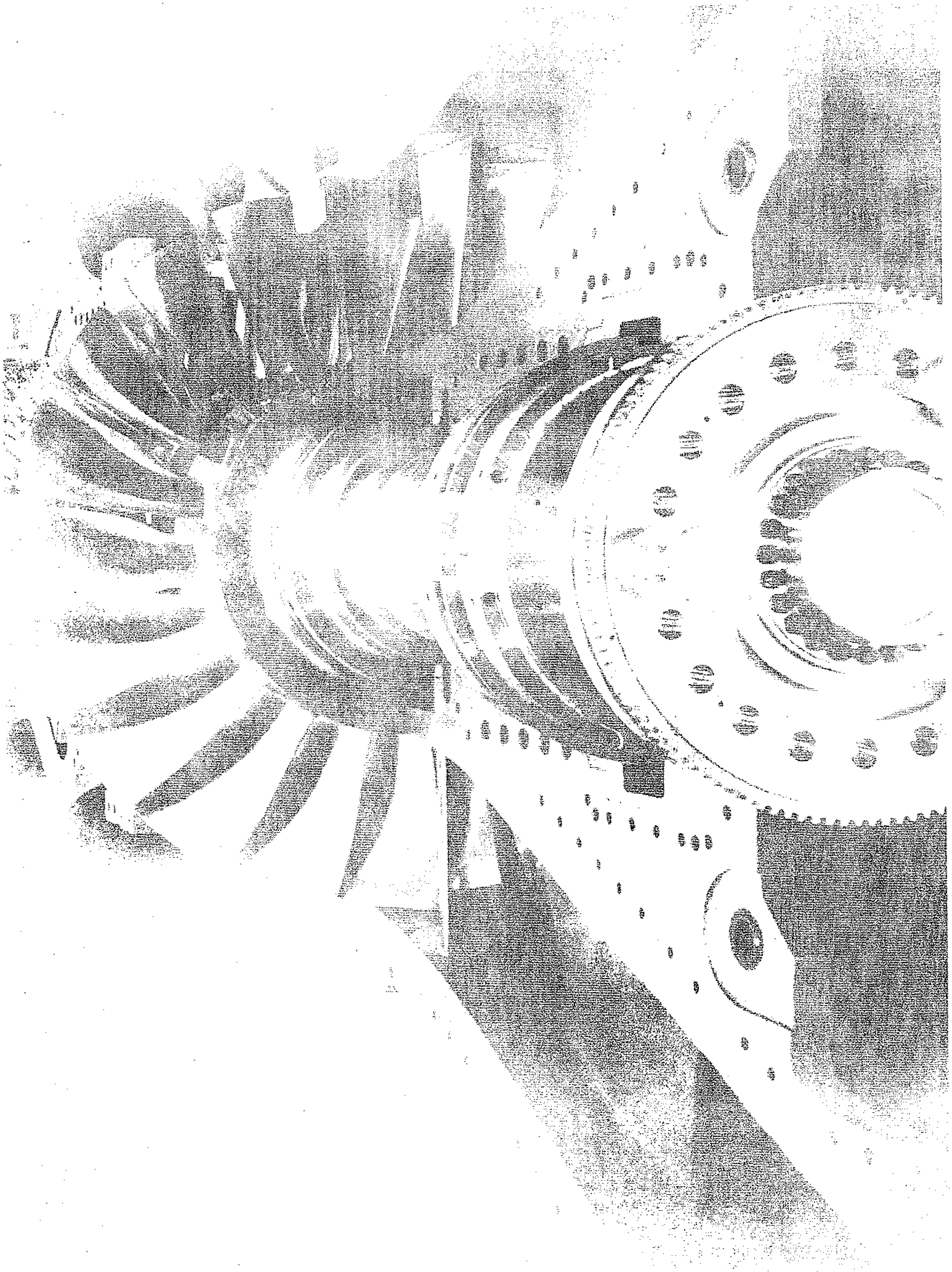
GE Energy

# H SYSTEM™

WORLD'S MOST ADVANCED COMBINED CYCLE TECHNOLOGY



imagination at work



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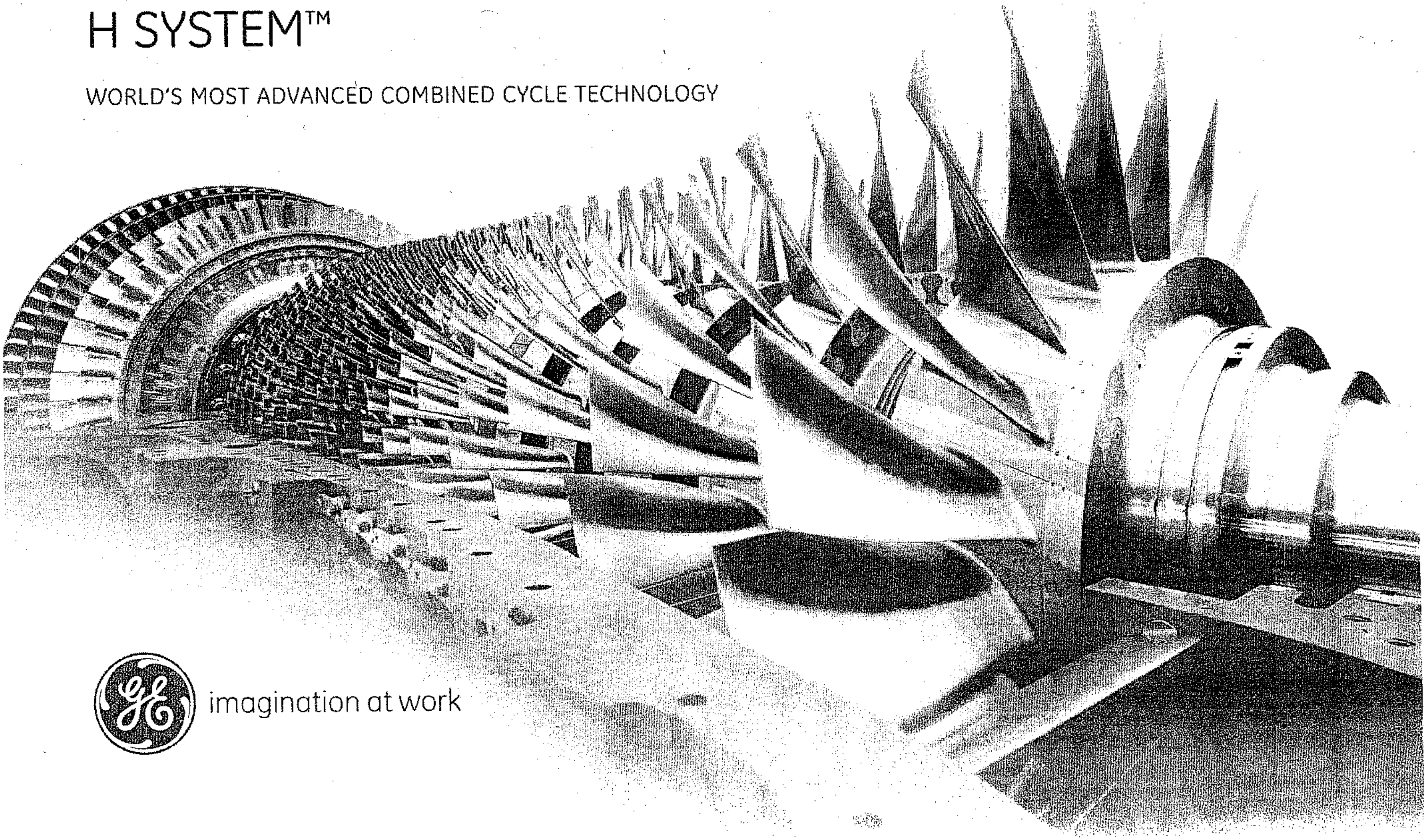

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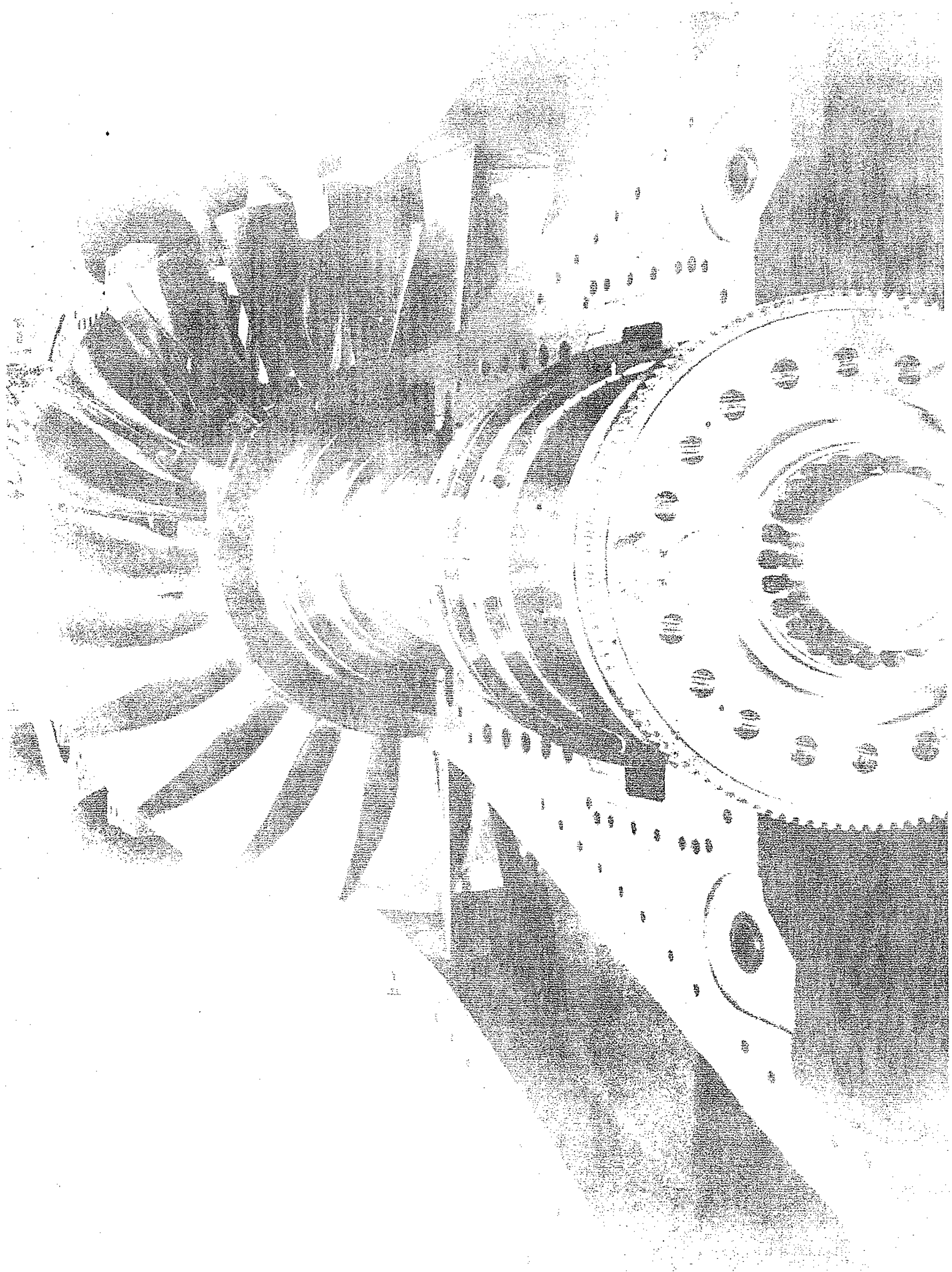
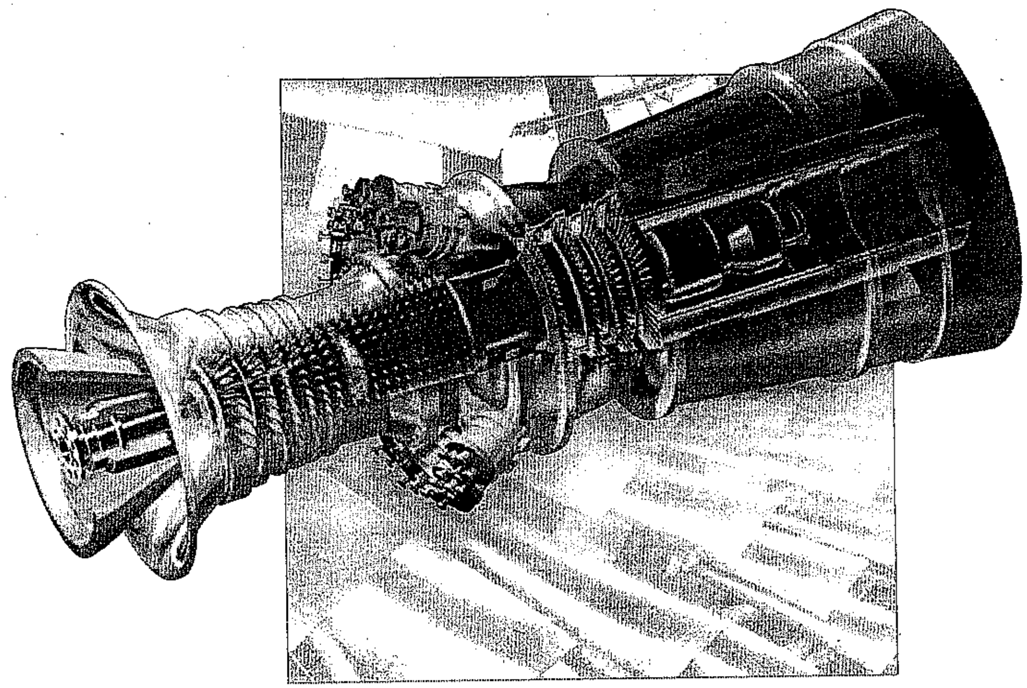


# World's Most Advanced Combined Cycle Gas Turbine Technology

GE's H System™—the world's most advanced combined cycle system and the first capable of breaking the 60% efficiency barrier—integrates the gas turbine, steam turbine and heat recovery steam generator into a seamless system, optimizing each component's performance. Undoubtedly the leading technology for both 50 and 60 Hz applications, the H delivers higher efficiency and output to reduce the cost of electricity of this gas-fired power generation system.

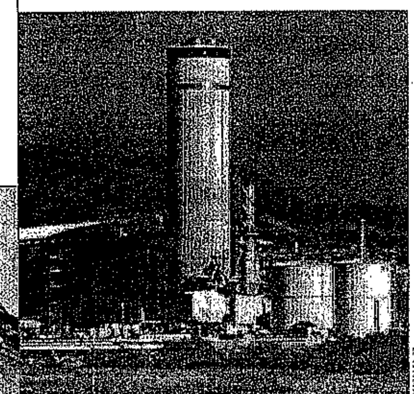


# H System™

## Closed-Loop Steam Cooling

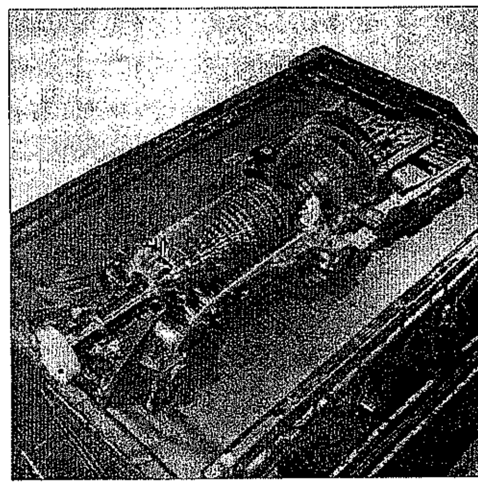
Open-loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which, for a given combustion temperature, reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance. It is this closed-loop steam cooling that enables the H System™ to achieve 60% fuel efficiency capability while maintaining strict adherence to environmental standards. For every unit of power it will use less fuel and produce fewer greenhouse gas emissions compared to other large gas turbines.

Baglan Bay Power Station Port Talbot Wales, UK is the launch site for GE's H System™.



## Single Crystal Materials

The use of these advanced materials, on the first stage nozzles and buckets, and Thermal Barrier Coatings, on the first and second stage nozzles and buckets, ensures that these components will stand up to high firing temperatures while meeting maintenance intervals.



An MS9001H is seen during assembly in the factory.

## Dry Low $NO_x$ Combustors

Building on GE's design experience, the H System™ employs a can-annular lean pre-mix DLN-2.5 Dry Low $NO_x$ (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low $NO_x$ levels in several million hours of field service around the world.

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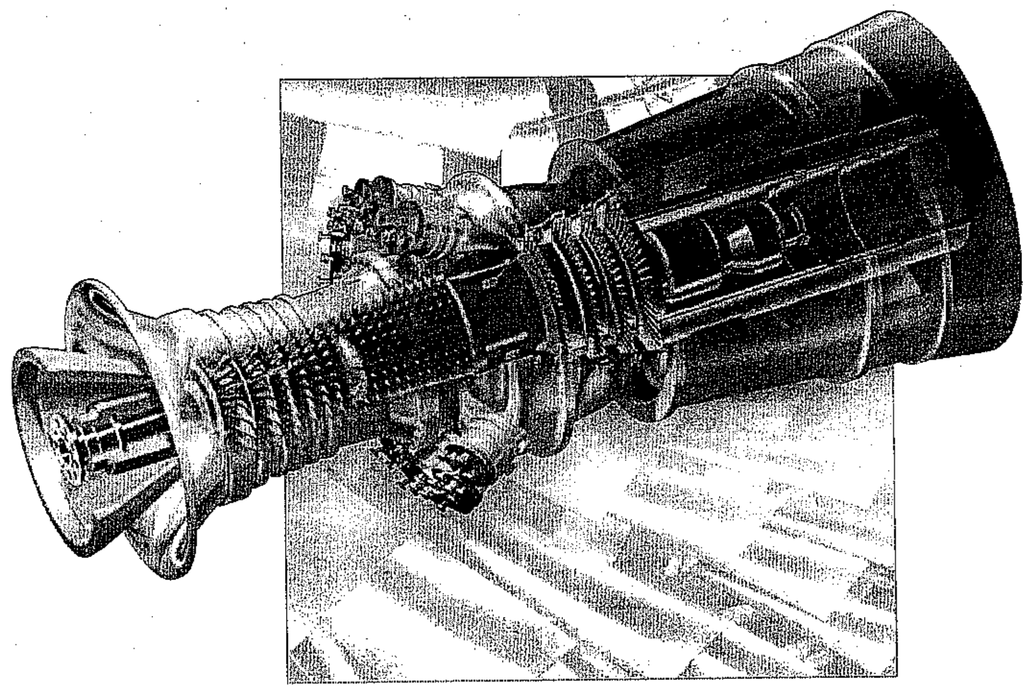

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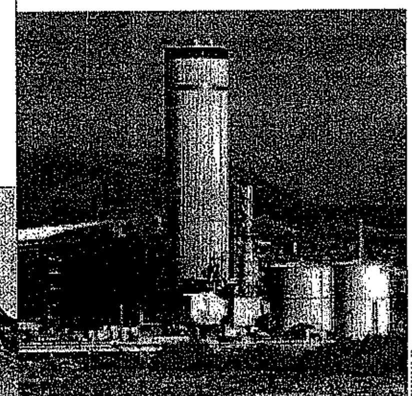

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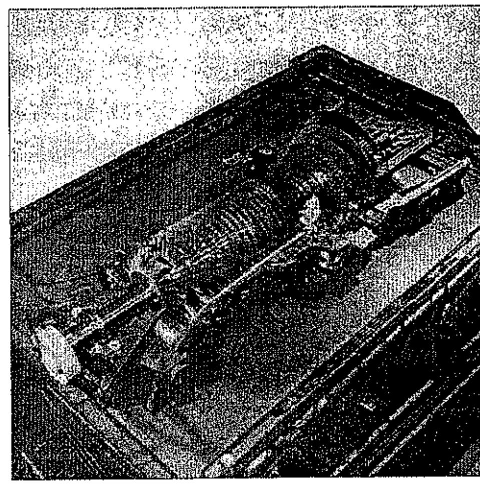

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## Small Footprint/High Power Density

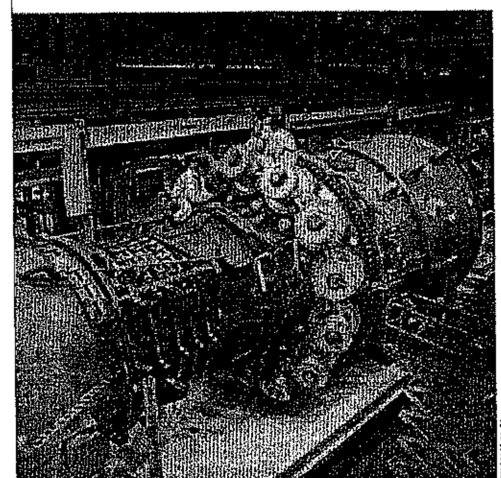
The H System™ offers approximately 40% improvement in power density per installed megawatt compared to other combined cycle systems, once again helping to reduce the overall cost of producing electricity.

## Thoroughly Tested

The design, development and validation of the H System™ has been conducted under a regimen of extensive component, sub-system and full unit testing. Broad commercial introduction has been controlled to follow launch units demonstration. This thorough testing approach provides the introduction of cutting edge technology with high customer confidence.

## MS9001H/MS7001H Combined Cycle Performance

| | | Net Plant Output (MW) | Heat Rate (Btu/kWh) | Heat Rate (kJ/kWh) | Net Plant Efficiency | GT Number & Type |
|---|---|---|---|---|---|---|
| 50 Hz | S109H | 520 | 5,690 | 6,000 | 60.0% | 1 x MS9001H |
| 60 Hz | S107H | 400 | 5,690 | 6,000 | 60.0% | 1 x MS7001H |



A 9H gas turbine is readied for testing.

# Baglan Bay Power Station Port Talbot, Wales*

100% GE-owned investment in validation of the revolutionary H System™ technology and turnkey construction—comprised of two power plants.

## 109H System Combined Cycle Power Plant

- 520 MW; single shaft
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; $NO_x$ emissions: < 25 ppm

**Steam Turbine:** GE design; reheat, single flow exhaust; co-mfg. with Toshiba

**Generator:** GE 550 MW LSTG; 660 MVA liquid cooled

**HRSG:** 3 pressure level reheat

## LM2500 Combined Heat and Power Plant

- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park**
  — Electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

## Other Baglan Power Station Features

- GE Mark VI-based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies Treatment Plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to Baglan Energy Park
- Pipeline Reception Facility (PRF)
  - For 12 km Baglan pipeline spur to National Transmission (Gas) System
  - Gas compression and pressure reduction capability, featuring GE centrifugal compressors

* Plant located on site leased from BP
** Baglan Energy Park
• Joint development among BP, Welsh Development Agency and Neath Port Talbot County Borough Council

Cover Photo: PSP30502-01. Inside Cover Photos: PSP30502-02, PSP30316. Designed by GE Energy's Creative Services team.

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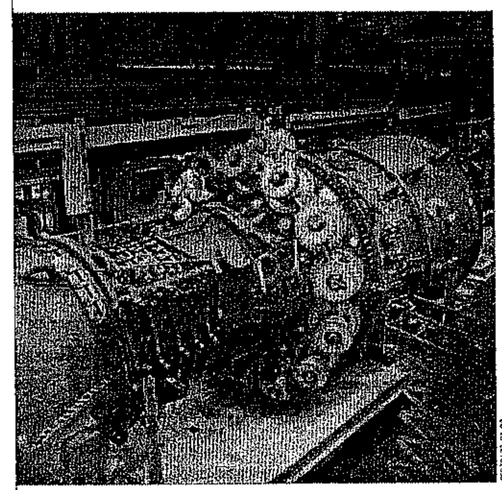

A 9H gas turbine is readied for testing.

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Cover Photo: PSP30502-01, Inside Cover Photos: PSP30502-02, PSP30336 Designed by GE Energy's Creative Services team.

## GE Products and Services Used at Baglan Include:

9H Gas Turbine, LP Steam Turbine, Generator and other Power Train Equipment and Accessories

EPC Project Management

Technical Advisors

Operations & Maintenance; Monitoring and Diagnostics

LM2500, Plant Compressors, Gas Compressors

Water Treatment Systems

2 MW Diesel Generator

Construction and Testing Power (Energy Rentals)

Switchyard Control System; GT Instruments

BOP PLCs and Operator Interfaces

Plant-Merchant Systems Integration Software

IT Integration Support

Plant Financing

Integrated Control System with Mark VIs

6.9 kV Switchgear

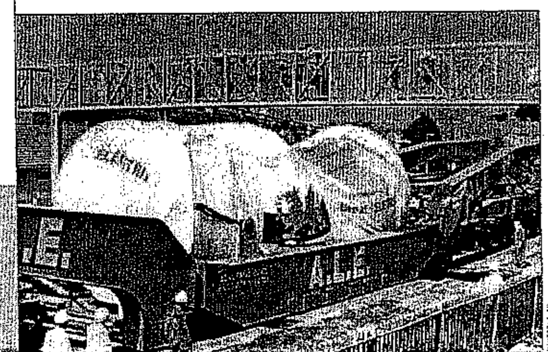
Various Pump and Valve Motors

Turbine Hall and BOP Lighting

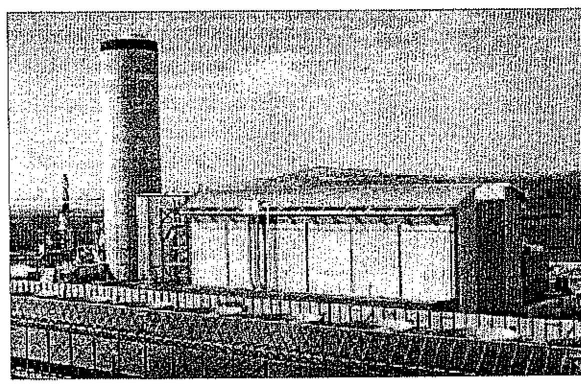
PRF Control Systems Integration

Commissioning

Pipe Installation Technical Advisors



World's first 9H gas turbine is transported through Wales to Baglan Bay Power Station.



GE Energy

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Atlanta, GA 30339

gepower.com

GEA 13585C (11/05)

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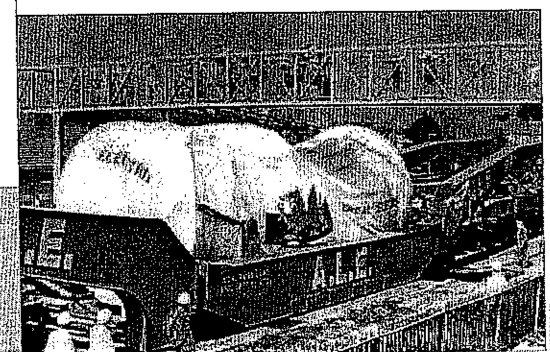

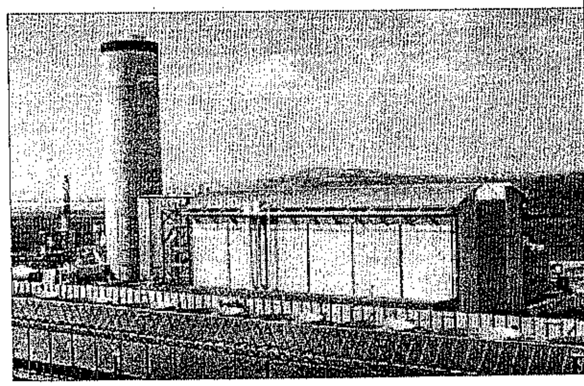

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GER-3935B

GE Power Systems

# Power Systems for the 21st Century – "H" Gas Turbine Combined-Cycles

**R.K. Matta**
**G.D. Mercer**
**R.S. Tuthill**
GE Power Systems
Schenectady, NY

GER-3935B

GE Power Systems

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## Contents

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## Abstract

This paper provides an overview of GE's *H System*™ technology and describes the intensive development work necessary to bring this revolutionary technology to commercial reality. In addition to describing the magnitude of performance improvement possible through use of *H System*™ technology, this paper discusses the technological milestones during the development of the first 9H (50 Hz) and 7H (60 Hz) gas turbines.

To illustrate the methodical product development strategy used by GE, this paper discusses several technologies which are essential to the introduction of the *H System*™. Also included herein are analyses of the series of comprehensive tests of materials, components and subsystems which necessarily preceded full-scale field testing of the *H System*™. This paper validates one of the basic premises on which GE started the *H System*™ development program: Exhaustive and elaborate testing programs minimize risk at every step of this process, and increase the probability of success when the *H System*™ is introduced into commercial service.

In 1995, GE, the world leader in gas turbine technology for over half a century, introduced its new generation of gas turbines. This *H System*™ technology is the first gas turbine ever to achieve the milestone of 60% fuel efficiency. Because fuel represents the largest individual expense of running a power plant, an efficiency increase of even a single percentage point can substantially reduce operating costs over the life of a typical gas-fired, combined-cycle plant in the 400 to 500 megawatt range.

The *H System*™ is not simply a state-of-the-art gas turbine. It is an advanced, integrated, combined-cycle system every component of which is optimized for the highest level of performance.

The unique feature of an H technology, combined-cycle system is the integrated heat transfer system, which combines both the steam plant reheat process and gas turbine bucket and nozzle cooling. This feature allows the power generator to operate at a higher firing temperature, which in turn produces dramatic improvements in fuel-efficiency. The end result is generation of electricity at the lowest, most competitive price possible. Also, despite the higher firing temperature of the *H System*™, combustion temperature is kept at levels that minimize emission production.

GE has more than two million fired hours of experience in operating advanced technology gas turbines, more than three times the fired hours of competitors' units combined. The *H System*™ design incorporates lessons learned from this experience with knowledge gleaned from operating GE aircraft engines. In addition, the 9H gas turbine is the first ever designed using "Design for Six Sigma" methodology, which maximizes reliability and availability throughout the entire design process. Both the 7H and 9H gas turbines will achieve the reliability levels of our F-class technology machines.

GE has tested its *H System*™ gas turbine more thoroughly than any system previously introduced into commercial service. The *H System*™ gas turbine has undergone extensive design validation and component testing. Full-speed, no-load testing (FSNL) of the 9H was achieved in May 1998 and pre-shipment testing was completed in November 1999. This *H System*™ will also undergo approximately a half-year of extensive demonstration and characterization testing at the launch site.

Testing of the 7H began in December 1999, and full-speed, no-load testing was completed in February 2000. The 7H gas turbine will also be subjected to extensive demonstration and characterization testing at the launch site.

## Background and Rationale for the H System™

The use of gas turbines for power generation has been steadily increasing in popularity for more than five decades. Gas turbine cycles are inherently capable of higher power density, higher fuel efficiency, and lower emissions than the competing platforms. Gas turbine performance is driven by the firing temperature, which is directly related to specific output, and inversely related to fuel consumption per kW of output. This means that increases in firing temperature provide higher fuel efficiency (lower fuel consumption per kW of output) and, at the same time, higher specific output (more kW per pound of air passing through the turbine).

The use of aircraft engine materials and cooling technology has allowed firing temperature for GE's industrial gas turbines to increase steadily. However, higher temperatures in the combustor also increase $NO_x$ production. In the "Conceptual Design" section of this paper, we describe how the GE *H System*™ solved the $NO_x$ problem, and is able to raise firing temperature by 200°F / 110°C over the current "F" class of gas turbines and hold the $NO_x$ emission levels at the initial "F" class levels.

The General Electric Company is made up of a number of different businesses. The company has thrived and grown due, in part, to the rapid transfer of improved technology and business practices among these businesses. The primary technology transfer channel is the GE Corporate Research & Development (CR&D) Center located in Schenectady, NY. The *H System*™ new product introduction (NPI) team is also located in Schenectady, facilitating the efficient transfer of technology from CR&D to the NPI team. Formal technology councils, including, for instance, the Thermal Barrier Coatings Council, High Temperature Materials Council, and the Dry Low $NO_x$ (DLN) Combustion Council, also promote synergy among the businesses, fostering development of advanced technology.

GE Power Systems (GEPS) and GE Aircraft Engines (GEAE) share many common links, including testing facilities for DLN, compressor components, and steam turbine components. In a move which could only have occurred within GE, with its unique in-house resources, over 200 engineers were transferred from GEAE and CR&D to GEPS, to support the development of the *H System*™. These transfers became the core of the *H System™'s* "Design and Systems" teams. *H System*™ technology is shared in its entirety between GEPS and GEAE, including test data and analytical codes.

In contrast to the free exchange of core technical personnel between GEPS and GEAE, several of GE's competitors have been forced to purchase limited aircraft engine technology from outside companies. This approach results in the acquisition of a specific design with limited detail and flexibility, but with no understanding of the underlying core technology.

In contrast, the transfer from GE Aircraft Engines to GEPS includes, but is not limited to, the following technologies, which are described later in the paper:

- Compressor aerodynamics, mechanical design and scale model rig testing
- Full-scale combustor testing at operating pressures and temperatures
- Turbine aerodynamics, heat transfer, and nozzle cascade testing
- Transfer of materials and coating data
- Processing for turbine blade and wheel superalloys

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In contrast to the free exchange of core technical personnel between GEPS and GEAE, several of GE's competitors have been forced to purchase limited aircraft engine technology from outside companies. This approach results in the acquisition of a specific design with limited detail and flexibility, but with no understanding of the underlying core technology.

In contrast, the transfer from GE Aircraft Engines to GEPS includes, but is not limited to, the following technologies, which are described later in the paper:

- Compressor aerodynamics, mechanical design and scale model rig testing
- Full-scale combustor testing at operating pressures and temperatures
- Turbine aerodynamics, heat transfer, and nozzle cascade testing
- Transfer of materials and coating data
- Processing for turbine blade and wheel superalloys

- Gas turbine instrumentation application and monitoring.

Technology contributed by CR&D includes:

- Development of heat transfer and fluid flow codes
- Process development for thermal barrier coatings
- Materials characterization and data
- Numerous special purpose component and subsystem tests
- Design and introduction of non-destructive evaluation techniques.

## Conceptual Design

The GE *H System*™ is a combined-cycle plant. The hot gases from the gas turbine exhaust proceed to a downstream boiler or heat recovery steam generator (HRSG). The resulting steam is passed through a steam turbine and the steam turbine output then augments that from the gas turbine. The output and efficiency of the steam turbine's "bottoming cycle" is a function of the gas turbine exhaust temperature.

For a given firing temperature class, 2600°F / 1430°C for the *H System*™, the gas turbine exhaust temperature is largely determined by the work required to drive the compressor, that is, in turn, affected by the "compressor pressure ratio". The *H System*™*'s* pressure ratio of 23:1 was selected to optimize the combined-cycle performance, while at the same time allowing for an uncooled last-stage gas turbine bucket, consistent with past GEPS practice.

The 23:1 compressor-pressure ratio, in turn, determined that using four turbine stages would provide the optimum performance and cost solution. This is a major change from the earlier "F" class gas turbines, which used a 15:1 compressor-pressure ratio and three turbine stages. With the *H System*™*'s* higher pressure ratio, the use of only three turbine stages would have increased the loading on each stage to a point where unacceptable reduction in stage efficiencies would result. By using four stages, the H turbine is able to specify optimum work loading for each stage and achieve high turbine efficiency.

## The Case for Steam Cooling

The GE *H System*™ gas turbine uses closed-loop steam cooling of the turbine. This unique cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. It is this closed-loop steam cooling that enabled the combined-cycle GE *H System*™ to achieve 60% fuel efficiency while maintaining adherence to the strictest, low $NO_x$ standards (*Figure 1*).

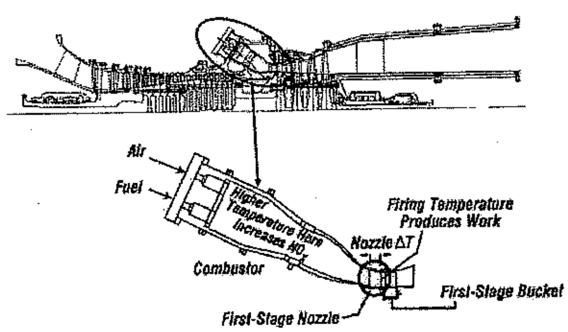


**Figure 1.** Combustion and firing temperatures

Combustion temperature must be as low as possible to establish low $NO_x$ emissions, while the firing temperature must be as high as possible for optimum cycle efficiency. The goal is to adequately cool the stage 1 nozzle, while minimizing the decrease in combustion product temperature as it passes through the stage 1 nozzle. This is achieved with closed-loop steam cooling.

In conventional gas turbines, with designs predating the *H System*™, the stage 1 nozzle is cooled with compressor discharge air. This cooling process causes a temperature drop across the stage 1 nozzle of up to 280°F/155°C. In H System™ gas turbines, cooling the stage 1 nozzle with a closed-loop steam coolant reduces the temperature drop across that nozzle to less than 80°F/44°C (*Figure 2*). This results in a firing temperature class of 2600°F/1430°C, or 200°F/110°C higher than in preceding systems, yet with no increase in combustion temperature. An additional benefit of the *H System*™ is that while the steam cools the nozzle, it picks up heat for use in the steam turbine, transferring what was traditionally waste heat into usable output. The third advantage of closed-loop cooling is that it minimizes parasitic extraction

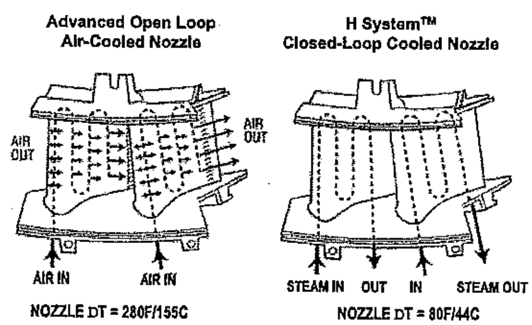


**Figure 2.** Impact of stage 1 nozzle cooling method

of compressor discharge air, thereby allowing more to flow to the head-end of the combustor for fuel premixing.

In conventional gas turbines, compressor air is also used to cool rotational and stationary components downstream of the stage 1 nozzle in the turbine section. This air is traditional labeled as "chargeable air", because it reduces cycle performance. In *H System*™ gas turbines, this "chargeable air" is replaced with steam, which enhances cycle performance by up to 2 points in efficiency, and significantly increases the gas turbine output, since all the compressor air can be channeled through the turbine flowpath to do useful work. A second advantage of replacing "chargeable air" with steam accrues to the *H System™'s* cycle through recovery of the heat removed from the gas turbine in the bottoming cycle.

## H Technology, Combined-Cycle System

The H technology, combined-cycle system consists of a gas turbine, a three-pressure-level HRSG and a reheat steam turbine.

The features of the combined-cycle system, which include the coolant steam flow from the steam cycle to the gas turbine, are shown in *Figure 3*. The high-pressure steam from the HRSG is expanded through the steam turbine's high-pressure section. The exhaust steam from this turbine section is then split. One part is returned to the HRSG for reheating; the other is combined with intermediate-pressure (IP) steam and used for cooling in the gas turbine.

Steam is used to cool the stationary and rotational parts of the gas turbine. In turn, the heat transferred from the gas turbine increases the steam temperature to approximately reheat temperature. The gas turbine cooling steam is returned to the steam cycle, where it is mixed with the reheated steam from the HRSG and introduced to the IP steam turbine section. Further details about the H combined-cycle system and its operation can be found in GER 3936A, "Advanced Technology Combined-Cycles" and will not be repeated in this paper.

## H Product Family and Performance

The H technology, with its higher pressure ratio and higher firing temperature design, will establish a new family of gas turbine products. The 9H and 7H combined-cycle specifications

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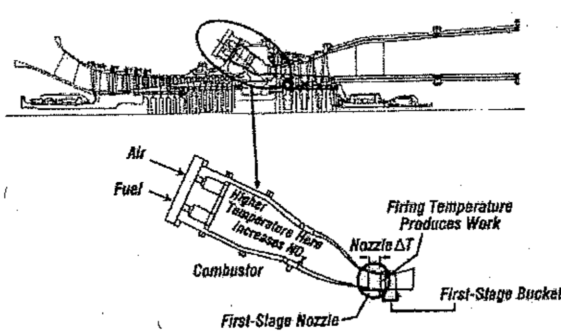


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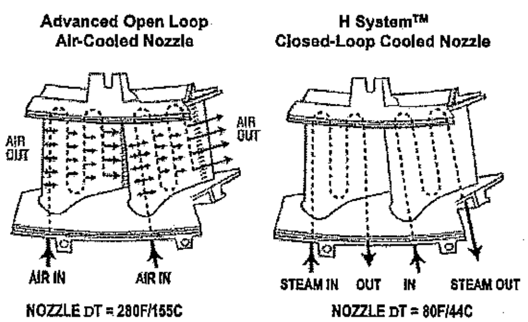


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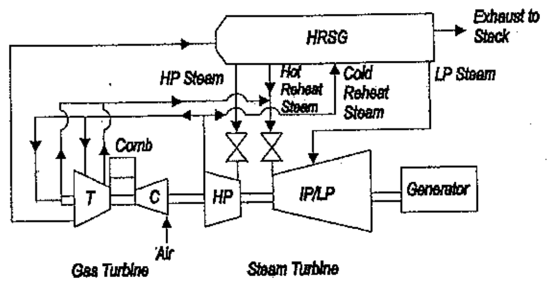


**Figure 3.** H Combined-cycle and steam description

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The 9H and 7H are not scaled geometrically to one another. This is a departure from past prac-

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| Pressure Ratio | 15 | 23 |
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**Table 1.** H Technology performance characteristics (50 Hz)

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**Table 2.** H Technology performance characteristics (60 Hz)

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One extremely attractive feature of the H technology, combined-cycle power plants is the high specific output. This permits compact plant designs with a reduced "footprint" when compared with conventional designs, and consequently, the potential for reduced plant capital costs (*Figure 4*). In a 60 Hz configuration, the H technology's compact design results in a 54% increase in output over the FA plants with an increase of just 10% in plant size.

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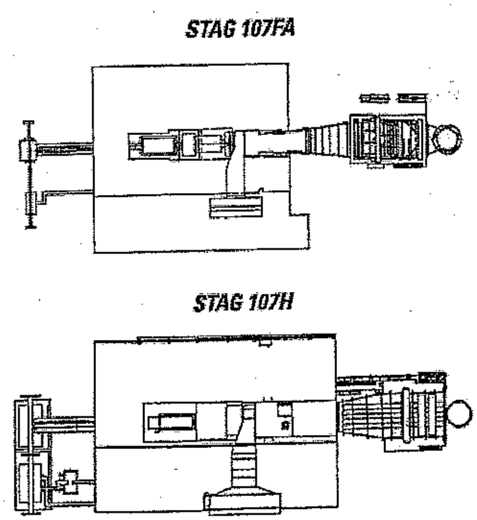


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The 7H development has made progress as part of the Advanced Turbine Systems program of the U.S. Department of Energy and its encouragement and support is gratefully acknowledged.

## System Strategy and Integration

While component and subsystem validation is necessary and is the focus of most NPI programs, other factors must also be considered in creating a successful product. The gas turbine must operate as a system, combining the compressor, combustor and turbine at design point (baseload), at part load turndown conditions, and at no load. The power plant and all power island components must also operate at steady state and under transient conditions, from start-up, to purge, to full speed.

Unlike traditional combined-cycle units, the *H System*™ gas turbine, steam turbine and HRSG are linked into one, interdependent system. Clearly, the reasoning behind these GE *H System*™ components runs contrary to the traditional approach, which designs and specifies each component as a stand-alone entity. In the *H System*™, the performance of the gas turbine, combined-cycle and balance of plant has been modeled, both steady state and transient; and analyzed in detail, as one large, integrated system, from its inception.

The GE *H System*™ concept incorporates an integrated control system (ICS) to act as the glue, which ties all the subsystems together (*Figure 5*).

Systems and controls teams, working closely with one another as well as with customers, have formulated improved hardware, software, and control concepts. This integration was facilitated by a new, third-generation, full-authority digital system, the Mark VI controller. This control system was designed with and is supplied by GE Industrial Systems (GEIS), which is yet another GE business working closely with GEPS.

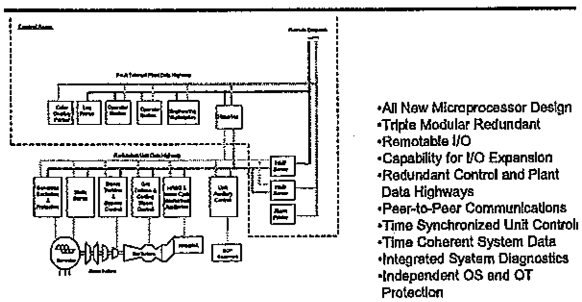


**Figure 5.** Mark VI – ICS design integrated with *H Systems™* design

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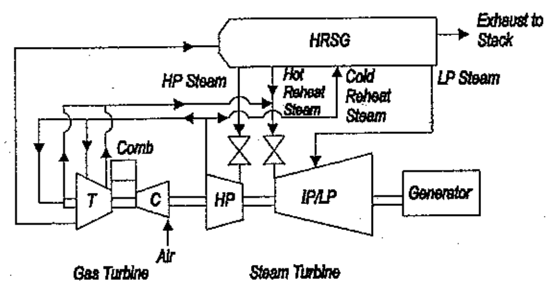


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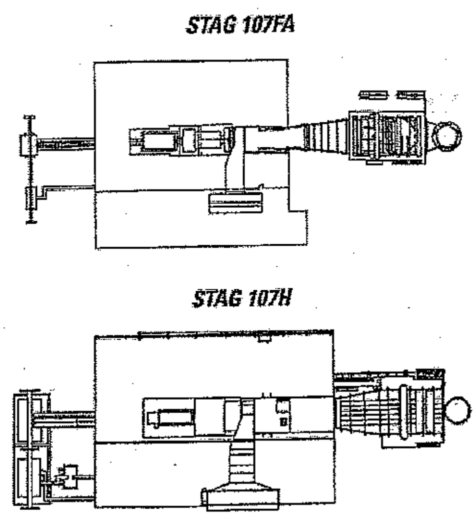


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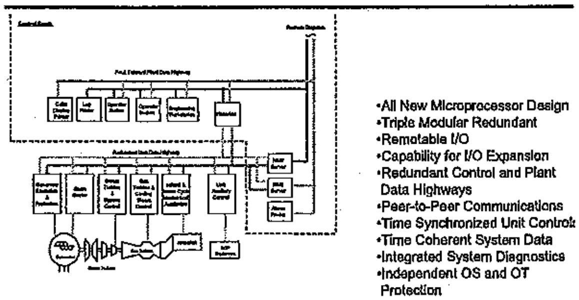


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## H Gas Turbine

The heart of the GE *H System*™ is the gas turbine. The challenges, design details, and validation program results follow. We start with a brief overview of the 9H and 7H gas turbine components (*Figure 6*).

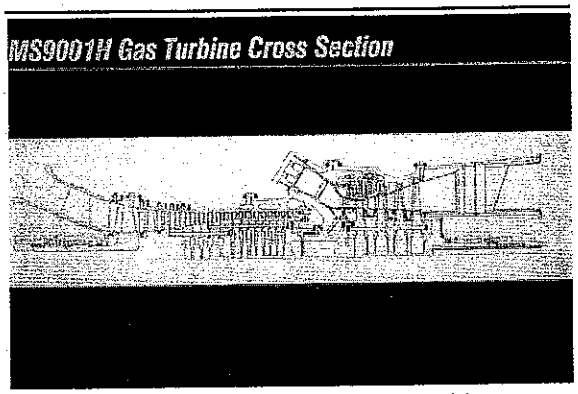



**Figure 6.** Cross-section H gas turbine

### Compressor Overview

The H compressor provides a 23:1 pressure ratio with 1510 lb/s (685 kg/s) and 1230 lb/s (558 kg/s) airflow for the 9H and 7H gas turbines, respectively. These units are derived from the high-pressure compressor GE Aircraft Engines (GEAE) used in the CF6-80C2 aircraft engine and the LM6000 aeroderivative gas turbine. For use in the H gas turbines, the CF6-80C2 compressor has been scaled up (2.6:1 for the MS7001H and 3.1:1 for the MS9001H) with four stages added to achieve the desired combination of airflow and pressure ratio. The CF6 compressor design has accumulated over 20 million hours of running experience, providing a solid design foundation for the *H System*™ gas turbine.

In addition to the variable inlet guide vane (IGV), used on prior GE gas turbines to modulate airflow, the H compressors have variable stator vanes (VSV) at the front of the compressor. They are used, in conjunction with the IGV, to control compressor airflow during turndown, as well as to optimize operation for variations in ambient temperature.

### Combustor Overview

The *H System*™ can-annular combustion system is a lean pre-mix DLN-2.5 *H System*™, similar to the GE DLN combustion systems in FA-class service today. Fourteen combustion chambers are used on the 9H, and twelve combustion chambers are used on the 7H. DLN combustion systems have demonstrated the ability to achieve low $NO_x$ levels in field service and are capable of meeting the firing temperature requirements of the GE *H System*™ gas turbine while obtaining single-digit (ppm) $NO_x$ and CO emissions.

### Turbine Overview

The case for steam cooling was presented earlier under Conceptual Design. The GE *H System*™ gas turbine's first two stages use closed-loop steam cooling, the third stage uses air cooling, while the fourth and last stage is uncooled.

Closed-loop cooling eliminates the film cooling on the gas path side of the airfoil, and increases the temperature gradients through the airfoil walls. This method of cooling results in higher thermal stresses on the airfoil materials, and has led GEPS to use single-crystal super-alloys for the first stage, in conjunction with thin ceramic thermal barrier coatings (*Figure 7*). This is a combination that GEAE has employed in its jet engines for 20 years. GEPS reached into the extensive GEAE design, analysis, testing and production database and worked closely with GEAE, its supplier base, and CR&D to translate this experience into a reliable and effective feature of the *H System*™ gas turbine design.

GE follows a rigorous system of design practices which the company has developed through hav-

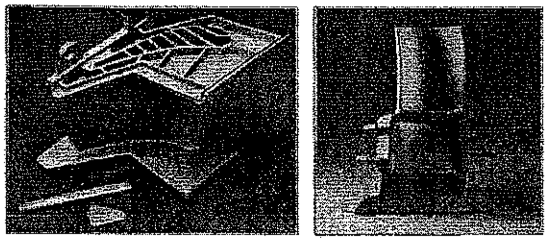


**Figure 7.** H Stage 1 nozzle and bucket – single crystal

ing a wide range of experiences with gas turbines in the last 20 years. For instance, GEAE's experience base of over 4000 parts indicates that thermal barrier coating on many airfoils is subject to loss early in operation, and that maximization of coating thickness is limited by deposits from environmental elements, evidenced by coating spallation when thickness limits are exceeded. Through laboratory analyses and experience-based data and knowledge, GE has created an airfoil that has shown, during field tests, that it maintains performance over a specific minimum cyclic life coatings, even with localized loss of coatings, as has been noted during field service.

## Gas Turbine Validation: Testing to Reduce Risk

Although GEPS officially introduced the *H System*™ concept and two product lines, the 9H and 7H gas turbines, to the industry in 1995, *H System*™ technology has been under development since 1992. The development has been a joint effort among GEPS, GEAE, and CR&D, with encouragement and support from the U.S. Department of Energy, and has followed GE's comprehensive design and technology validation plan that will, when complete, have spanned 10 years from concept to power plant commissioning.

The systematic design and technology-validation approach described in this paper has proved to be the aerospace and aircraft industry's most reliable practice for introduction of complex, cutting-edge technology products. The approach is costly and time consuming, but is designed to deliver a robust product into the field for initial introduction. At its peak, the effort to develop and validate the *H System*™ required the employment of over 600 people and had annual expenses of over $100 million.

Other suppliers perceive that design and construction of a full-scale prototype may be a faster development-and-design approach. However, it is difficult, if not impossible, for a prototype to explore the full operating process in a controlled fashion. For example, prototype testing limits the opportunity to evaluate alternative compressor stator gangs and to explore cause-and-effect among components when problems are encountered. The prototype approach also yields a much greater probability of failure during the initial field introduction of a product than does the comprehensive design approach, coupled with "Six Sigma" disciplines and the technology validation plan used by GE (*Figure 8*).

The first phase in the *H System*™ development process was a thorough assessment of product options, corresponding design concepts, and system requirements. Also crucial in the first phase was careful selection of materials, components and subsystems. These were sorted into categories of existing capabilities or required technology advancements. All resources and technological capabilities of GEAE and CR&D were made available to the Power Systems' H-technology team.

For each component and subsystem, risk was assessed and abatement analyses, testing, and

## H Gas Turbine

The heart of the GE *H System*™ is the gas turbine. The challenges, design details, and validation program results follow. We start with a brief overview of the 9H and 7H gas turbine components (*Figure 6*).

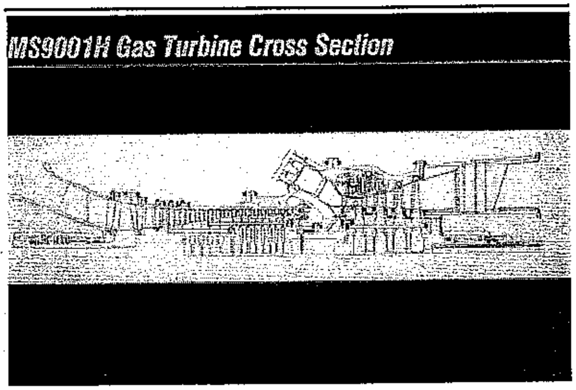



**Figure 6.** Cross-section H gas turbine

### Compressor Overview

The H compressor provides a 23:1 pressure ratio with 1510 lb/s (685 kg/s) and 1230 lb/s (558 kg/s) airflow for the 9H and 7H gas turbines, respectively. These units are derived from the high-pressure compressor GE Aircraft Engines (GEAE) used in the CF6-80C2 aircraft engine and the LM6000 aeroderivative gas turbine. For use in the H gas turbines, the CF6-80C2 compressor has been scaled up (2.6:1 for the MS7001H and 3.1:1 for the MS9001H) with four stages added to achieve the desired combination of airflow and pressure ratio. The CF6 compressor design has accumulated over 20 million hours of running experience, providing a solid design foundation for the *H System*™ gas turbine.

In addition to the variable inlet guide vane (IGV), used on prior GE gas turbines to modulate airflow, the H compressors have variable stator vanes (VSV) at the front of the compressor. They are used, in conjunction with the IGV, to control compressor airflow during turndown, as well as to optimize operation for variations in ambient temperature.

### Combustor Overview

The *H System*™ can-annular combustion system is a lean pre-mix DLN-2.5 *H System*™, similar to the GE DLN combustion systems in FA-class service today. Fourteen combustion chambers are used on the 9H, and twelve combustion chambers are used on the 7H. DLN combustion systems have demonstrated the ability to achieve low $NO_x$ levels in field service and are capable of meeting the firing temperature requirements of the GE *H System*™ gas turbine while obtaining single-digit (ppm) $NO_x$ and CO emissions.

### Turbine Overview

The case for steam cooling was presented earlier under Conceptual Design. The GE *H System*™ gas turbine's first two stages use closed-loop steam cooling, the third stage uses air cooling, while the fourth and last stage is uncooled.

Closed-loop cooling eliminates the film cooling on the gas path side of the airfoil, and increases the temperature gradients through the airfoil walls. This method of cooling results in higher thermal stresses on the airfoil materials, and has led GEPS to use single-crystal super-alloys for the first stage, in conjunction with thin ceramic thermal barrier coatings (*Figure 7*). This is a combination that GEAE has employed in its jet engines for 20 years. GEPS reached into the extensive GEAE design, analysis, testing and production database and worked closely with GEAE, its supplier base, and CR&D to translate this experience into a reliable and effective feature of the *H System*™ gas turbine design.

GE follows a rigorous system of design practices which the company has developed through hav-

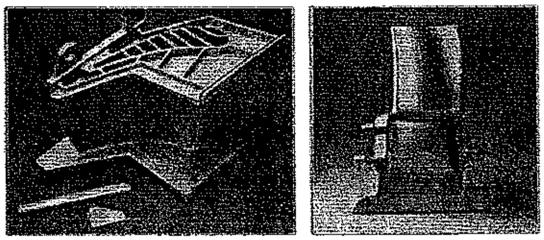


**Figure 7.** H Stage 1 nozzle and bucket – single crystal

ing a wide range of experiences with gas turbines in the last 20 years. For instance, GEAE's experience base of over 4000 parts indicates that thermal barrier coating on many airfoils is subject to loss early in operation, and that maximization of coating thickness is limited by deposits from environmental elements, evidenced by coating spallation when thickness limits are exceeded. Through laboratory analyses and experience-based data and knowledge, GE has created an airfoil that has shown, during field tests, that it maintains performance over a specific minimum cyclic life coatings, even with localized loss of coatings, as has been noted during field service.

## Gas Turbine Validation: Testing to Reduce Risk

Although GEPS officially introduced the *H System*™ concept and two product lines, the 9H and 7H gas turbines, to the industry in 1995, *H System*™ technology has been under development since 1992. The development has been a joint effort among GEPS, GEAE, and CR&D, with encouragement and support from the U.S. Department of Energy, and has followed GE's comprehensive design and technology validation plan that will, when complete, have spanned 10 years from concept to power plant commissioning.

The systematic design and technology-validation approach described in this paper has proved to be the aerospace and aircraft industry's most reliable practice for introduction of complex, cutting-edge technology products. The approach is costly and time consuming, but is designed to deliver a robust product into the field for initial introduction. At its peak, the effort to develop and validate the *H System*™ required the employment of over 600 people and had annual expenses of over $100 million.

Other suppliers perceive that design and construction of a full-scale prototype may be a faster development-and-design approach. However, it is difficult, if not impossible, for a prototype to explore the full operating process in a controlled fashion. For example, prototype testing limits the opportunity to evaluate alternative compressor stator gangs and to explore cause-and-effect among components when problems are encountered. The prototype approach also yields a much greater probability of failure during the initial field introduction of a product than does the comprehensive design approach, coupled with "Six Sigma" disciplines and the technology validation plan used by GE (*Figure 8*).

The first phase in the *H System*™ development process was a thorough assessment of product options, corresponding design concepts, and system requirements. Also crucial in the first phase was careful selection of materials, components and subsystems. These were sorted into categories of existing capabilities or required technology advancements. All resources and technological capabilities of GEAE and CR&D were made available to the Power Systems' H-technology team.

For each component and subsystem, risk was assessed and abatement analyses, testing, and

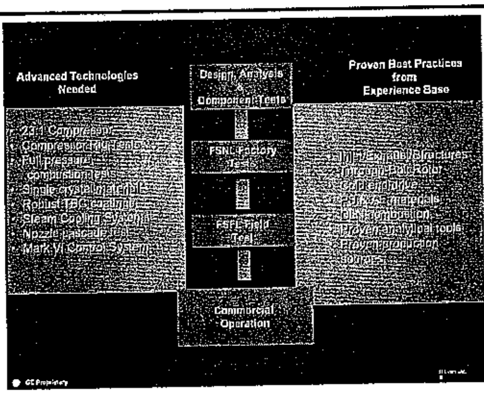



**Figure 8.** GE validation process

data were specified. Plans to abate risk and facilitate design were arranged, funded, and executed.

The second development phase covered product conceptual and preliminary designs, and included the introduction of knowledge gained through experience, materials data, and analytical codes from GEPS and GEAE.

The *H System*™ development program is currently in its third and final phase, technology readiness demonstration. This phase includes execution of detailed design and product validation through component and gas turbine testing. A high degree of confidence has been gained through component and subsystem testing and validation of analysis codes. Completion of the development program results in full-scale gas turbine testing at our factory test stand in Greenville, SC, followed by combined-cycle power plant testing at the Baglan Energy Park launch site, in the United Kingdom.

### Compressor Design Status

Modifications and proof-of-design are made through a rigorous design process that includes GEAE and GEPS experience-based analytical tools, component tests, compressor rig tests and instrumented product tests. The aerodynamic design process uses pitchline design and off-design performance evaluation, axisymmetric streamline curvature calculations with empiricism for secondary flows and mixing, two-dimensional inviscid blade-to-blade analysis and three dimensional viscous CFD blade row analysis. The aerodynamic design is iterated in concert with the aeromechanical design of the individual blade stages, optimizing on GEAE and GEPS experience-supported limits on blade loading, stage efficiency, surge margin, stress limits, etc.

The program has completed the third and final compressor rig test at GEAE's Lynn, MA test facility.

Tests are run with CF6 full-scale hardware, which amounts to a one-third scale test for the 9H and 7H gas turbines. Each rig test is expensive, approximately $20M, but provides validation and flexibility, significantly surpassing any other test options. The 7H rig test had over 800 sensors and accumulated over 150 hours to characterize the compressor's aerodynamic and aeromechanical operations (*Figure 9*). Key test elements include optimum ganging of the variable guide vanes and stators; performance mapping to quantify airflow, efficiency, and stall margins; stage pressure and temperature splits; start-up, acceleration, and turndown character-

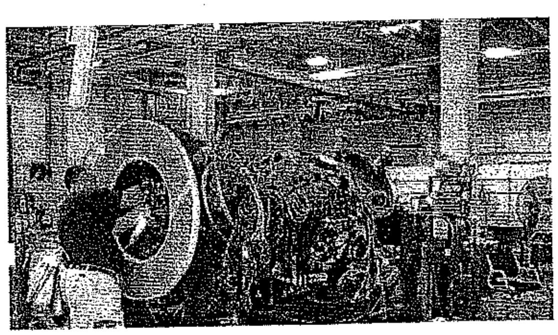


**Figure 9.** 7H compressor test rig

istics; and identification of flutter and vibratory characteristics of the airfoils (aeromechanics).

The three-test series has accomplished the following:

- Proof of concept, with four stages added to increase pressure ratio, and initial power generation operability – completed August 1995.
- 9H compressor design validation and maps including tri-passage diffuser performance and rotor cooling proof-of-concept – completed August 1997.
- 7H compressor design validation – completed August 1999, (*Figure 10*)

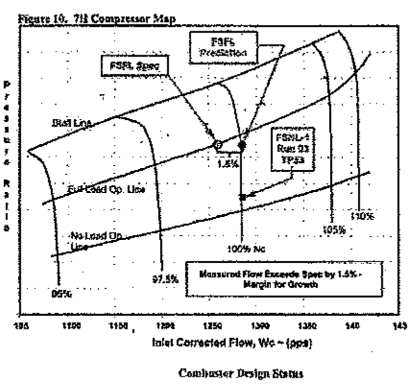


**Figure 10.** Compressor map

## Combustor Design Status

*Figure 11* shows a cross-section of the combustion system. The technical approach features a tri-passage radial prediffuser which optimizes the airflow pressure distribution around the combustion chambers, a GTD222 transition piece with an advanced integral aft frame mounting arrangement, and impingement sleeve cooling of the transition piece. The transition piece seals are the advanced cloth variety for minimum leakage and maximum wear resistance. The flow sleeve incorporates

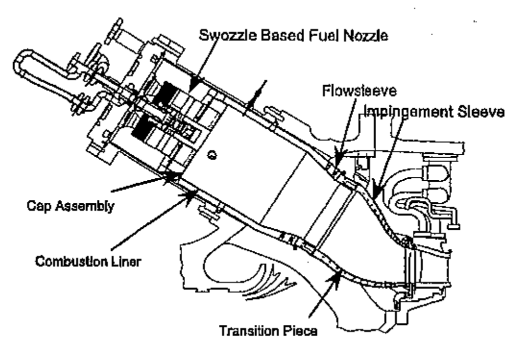



**Figure 11.** Combustion system cross-section

impingement holes for liner aft cooling. The liner cooling is of the turbolator type so that all available air can be allocated to the reaction zone to reduce $NO_X$. Advanced 2-Cool™ composite wall convective cooling is utilized at the aft end of the liner. An effusion-cooled cap is utilized at the forward end of the combustion chamber.

## Fuel Injector Design Status

The *H System*™ fuel injector is shown in *Figure 12* and is based on the swozzle concept. The term swozzle is derived by joining the words "swirler" and "nozzle." The premixing passage of the swozzle utilizes swirl vanes to impart rotation to the admitted airflow, and each of these swirl vanes also contains passages for injecting fuel into the premixer airflow. Thus, the premixer is very aerodynamic and highly resistant

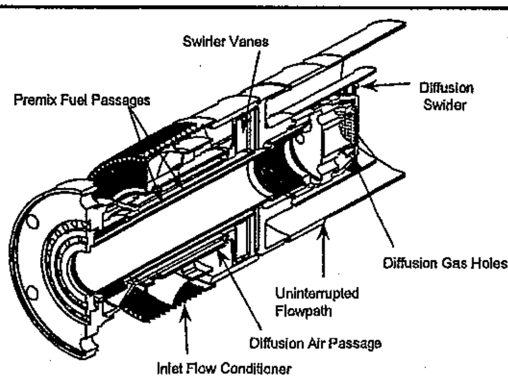
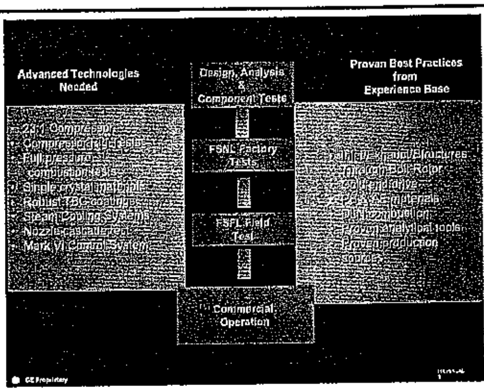



**Figure 12.** Fuel injector system cross-section

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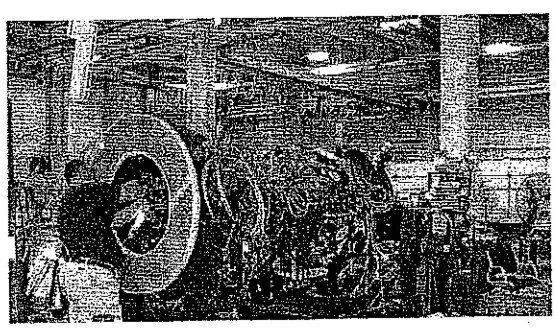

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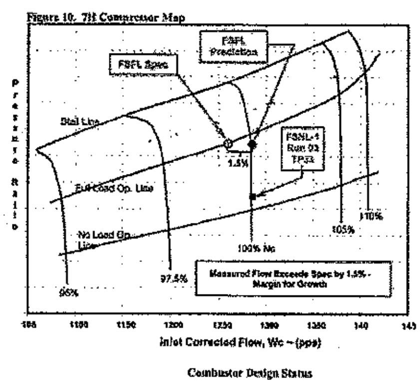


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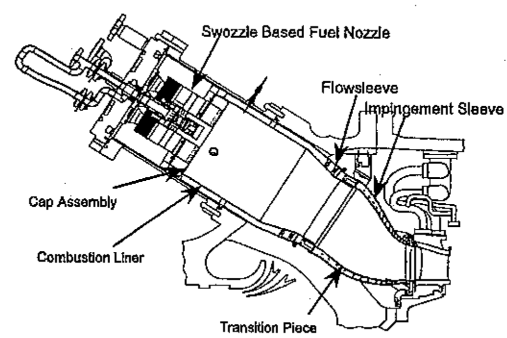


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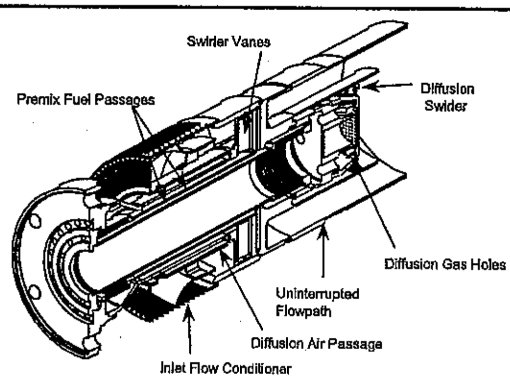



**Figure 12.** Fuel injector system cross-section

to flashback and flameholding. Downstream of the swozzle vanes, the outer wall of the premixer is integral to the fuel injector to provide added flameholding resistance. Finally, for diffusion flame starting and low load operation, a swirl cup is provided in the center of each fuel injector.

The *H System*™ combustor uses a simplified combustion mode staging scheme to achieve low emissions over the premixed load range while providing flexible and robust operation at other gas turbine loads. *Figure 13* shows a schematic diagram of the staging scheme. The most significant attribute is that there are only

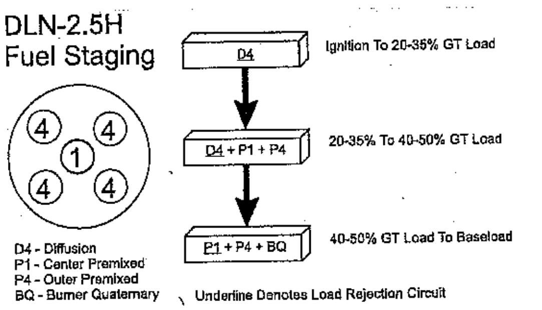



**Figure 13.** Combustion mode staging scheme

three combustion modes: diffusion, piloted premix, and full premix mode. These modes are supported by the presence of four fuel circuits: outer nozzle premixed fuel (P4), center nozzle premixed fuel (P1), burner quaternary premixed fuel (BQ), and diffusion fuel (D4). The gas turbine is started on D4, accelerated to Full-Speed No-Load (FSNL), and loaded further. At approximately 20-35% gas turbine load, two premixed fuel streams P1, and P4, are activated in the transfer into piloted premix. After loading the gas turbine to approximately 40-50% load, transfer to full premix mode is made and all D4 fuel flow is terminated while BQ fuel flow is activated. This very simplified staging strategy has major advantages for smooth unit operability and robustness.

The *H System*™ combustor was developed in an extensive test series to ensure low emissions, quiet combustion dynamics, ample flashback/flameholding resistance, and rigorously assessed component lifing supported by a complete set of thermal data. In excess of thirty tests were run at the GEAE combustion test facility, in Evendale, OH, with full pressure, temperature, and airflow. *Figure 14* shows typical $NO_x$ baseload emissions as a function of combustor exit temperature, and *Figure 15* shows the comparable combustion dynamics data. The H components have significant margin in each case. In addition, hydrogen torch

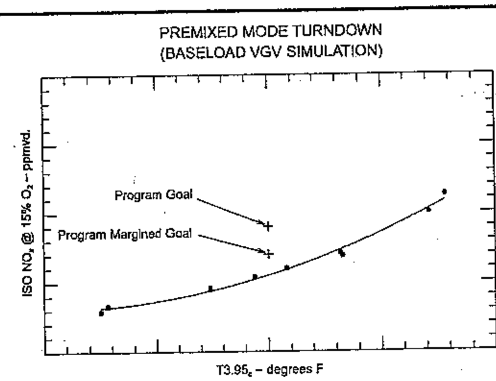



**Figure 14.** $NO_x$ baseload emissions as a function of combustor exit temperature

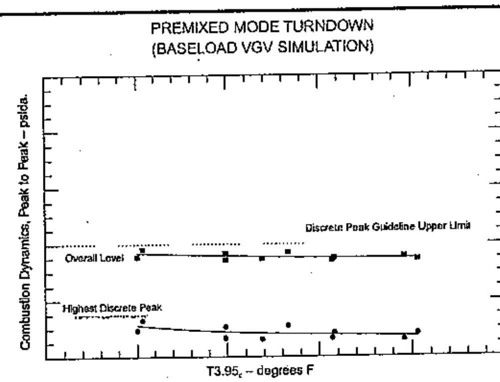



**Figure 15.** Comparable combustion dynamics data

ignition testing was performed on the fuel injector premixing passages. In all cases the fuel injectors exhibited well in excess of 30 ft/s flameholding margin after the hydrogen torch was de-activated. In addition, lifing studies have shown expected combustion system component lives with short term Z-scores between 5.5 and 7.5 relative to the combustion inspection intervals on a thermal cycles to crack initiation basis. Thus, there is a 99.9% certainty that component lifing goals will be met.

## Turbine Design Status

The turbine operates with high gas path temperatures, providing the work extraction to drive the compressor and generator. Two of the factors critical to reliable, long life are the turbine airfoil's heat transfer and material capabilities. When closed circuit steam cooling is used, as on the H turbine, the key factors do not change. However, the impact of steam on the airfoil's heat transfer and material capabilities must also be considered.

For many years, the U.S. Department of Energy (DOE) Advanced Turbine System has provided cooperative support for GE's development of the H System™ turbine heat transfer materials capability and steam effects. Results have fully defined and validated the factors vital to successful turbine operation. A number of different heat transfer tests have been performed to fully characterize the heat transfer characteristics of the steam-cooled components. *Figure 16* shows results for stage 1 nozzle internal cooling heat transfer. An extensive array of material tests has been performed to validate the material characteristics in a steam environment. Testing has included samples of base material and joints and the testing has addressed the following mechanisms: cyclic oxidation, fatigue crack propagation, creep, low-cycle fatigue and notched low-cycle fatigue (*Figure 17*).

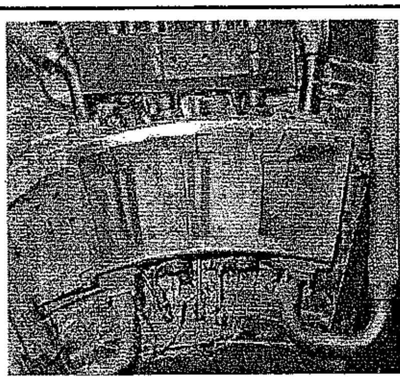


**Figure 16.** Full-scale stage 1 nozzle heat transfer test validates design and analysis predictions

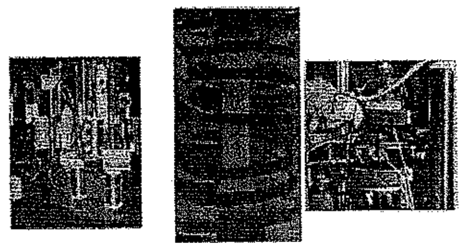
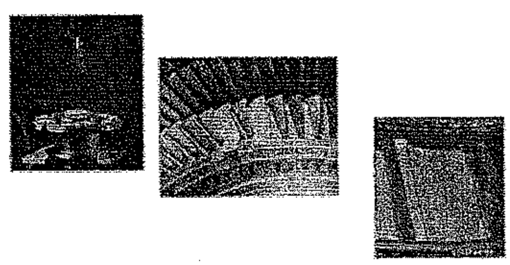


**Figure 17.** Materials validation testing in steam

Thermal barrier coating (TBC) is used on the flowpath surfaces of the steam-cooled turbine airfoils. Life validation has been performed using both field trials (*Figure 18*) and laboratory analysis. The latter involved a test that duplicates thermal-mechanical conditions, which the TBC will experience on the H System™ airfoils.

Long-term durability of the steam-cooled components is dependent on avoidance of internal deposit buildup, which is, in turn, dependent on steam purity. This is accomplished through system design and filtration of the gas turbine cooling steam. Long-term validation testing,



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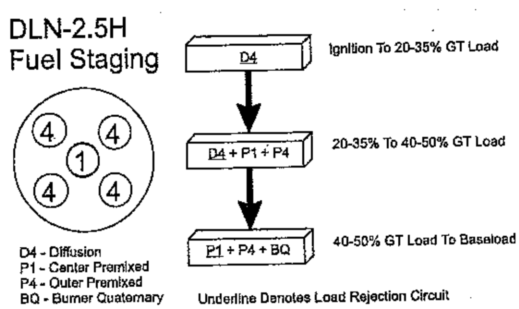


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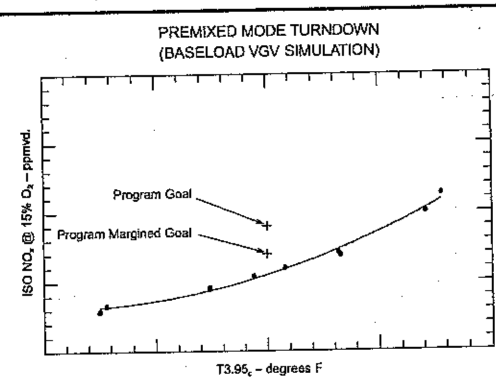


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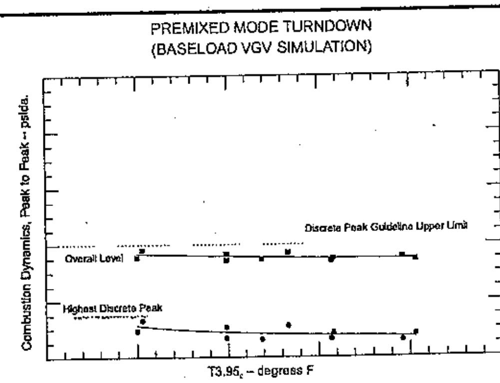


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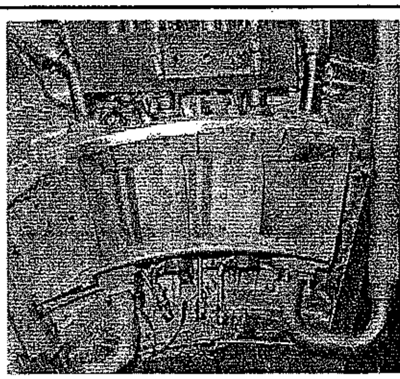

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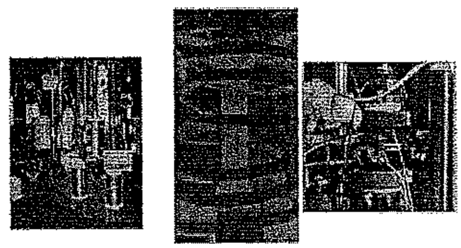

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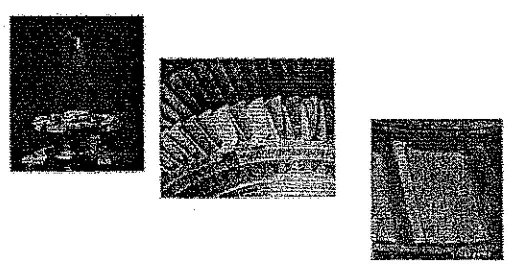


**Figure 18.** Thermal barrier coating durability

currently underway at an existing power plant, has defined particle size distribution and validated long-term steam filtration. As further validation, specimens duplicating nozzle cooling passages have initiated long-term exposure tests. A separate rotational rig is being used for bucket validation.

The H turbine airfoils have been designed using design data and validation test results for heat transfer, material capability and steam cooling effects. The durability of ceramic thermal barrier coatings has been demonstrated by three different component tests performed by CR&D:

- Furnace cycle test
- Jet engine thermal shock tests
- Electron beam thermal gradient testing

The electron beam thermal gradient test was developed specifically for GEPS to accurately simulate the very high heat transfers and gradients representative of the *H System*™ gas turbine. Heat transfers and gradients representative of the *H System*™ gas turbine have also been proven by field testing of the enhanced coatings in E- and F-class gas turbines.

The stage 1 nozzle, which is the H System™ component subjected to the highest operating temperatures and gradients, has been validated by another intensive component test. A nozzle cascade facility was designed and erected at GEAE (*Figure 19*). It features a turbine segment carrying two closed-loop steam-cooled nozzles downstream from a full-scale H System™ combustor and transition piece. This testing facility accurately provides the actual gas turbine operating environment. Two prototype nozzles complete with pre-spalled TBC were tested in April 1998. Data was obtained validating the aerodynamic design and heat transfer codes. Accelerated endurance test data was also obtained. A second test series, with actual 9H production nozzles, is scheduled to start in the 4th quarter of 2000).

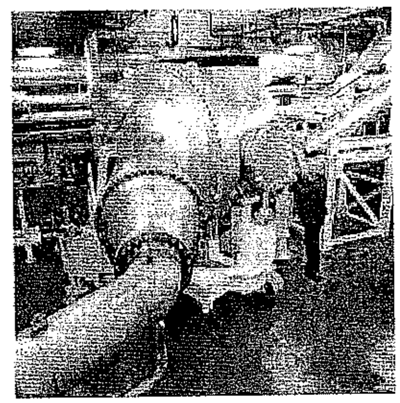


**Figure 19.** Nozzle cascade test facility

The rotor steam delivery system delivers steam for cooling stage 1 and 2 turbine buckets. This steam delivery system relies on "spoolies" to deliver steam to the buckets without detrimental leakage, which would lead to performance loss and adverse thermal gradients within the rotor structure. The basic concept for power system steam sealing is derived from many years of successful application of spoolies in the GE CF6 and CFM56 aircraft engine families.

In the conceptual design phase, material selection was made only after considering the effects of steam present in this application. Coatings to improve durability of the spoolie were also tested. These basic coupon tests and operational experience provided valuable information to the designers.

In the preliminary design phase, parametric analysis was performed to optimize spoolie configuration. Component testing began for both air and steam systems. The spoolie was instrumented to validate the analysis. Again, the combination of analysis and validation tests provided confirmation that the design(s) under consideration were based on the right concept.

Over 50 component tests have been conducted on these spoolies, evaluating coatings, lateral loads, fits, axial motion, angular motion, temperature and surface finish.

The detailed design phase focused on optimization of the physical features of the subsystem, spoolie-coating seat. In addition, refined analysis was performed to allow for plasticity lifecycle calculations in the region of the highest stresses. This analysis was again validated with a spoolie cyclic life test, which demonstrated effective sealing at machine operating conditions with a life over of 20,000 cycles.

Spoolies were also used on the *H System*™ FSNL gas turbine tests. During the 9H FSNL-2 testing, compressor discharge air flowed through the circuit. This is typical of any no-load operation. Assembly and disassembly tooling and processes were developed. The spoolies were subjected to a similar environment with complete mechanical G loading. Post-testing condition of the seals was correlated to the observation made on the component tests. This provided another opportunity for validation.

A rotating steam delivery rig (*Figure 20*) has been designed and manufactured to conduct cyclic endurance testing of the delivery system under any load environment. The rotating rig will subject components to the same centrifugal forces and thermal gradients that occur during actual operation of the turbine. This system testing will provide accelerated lifecycle testing.

Leakage checks will be completed periodically to monitor sealing effectiveness. Test rig instrumentation will insure that the machine matches the operating environment. The rig has been installed in the test cell, and testing should resume in April 2000.

## Gas Turbine Factory Tests

The first six years of the GE H System™ validation program focused on sub-component and component tests. Finally, in May 1998, the program moved on to the next stage, that of full-scale gas turbine testing at the Greenville, South Carolina factory (*Figure 21*). The 9H gas turbine achieved first fire and full speed and, then, over a space of five fired tests, accomplished the full set of objectives. These objectives included confirmation of rotor dynamics: vibration levels and onset of different modes; compressor airfoil aero-mechanics; compressor performance, including confirmation of airflow and efficiency scale-up effects vs. the CF6 scale rig tests; measurement of compressor and turbine rotor clearances; and demonstration of the gas turbine with the Mark VI control system.

The testing also provided data on key systems:

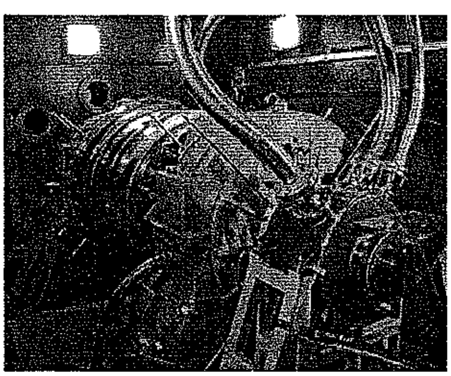


**Figure 20.** Rotating rig installed in test stand

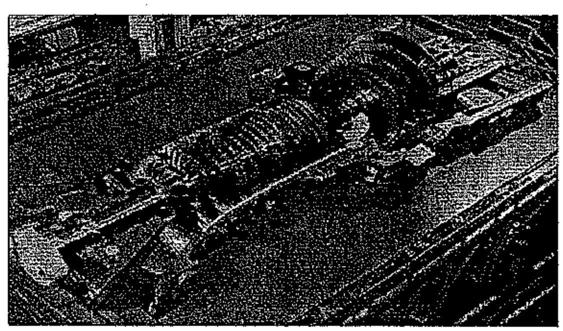


**Figure 21.** 9H gas turbine in half shell prior to first FSNL test

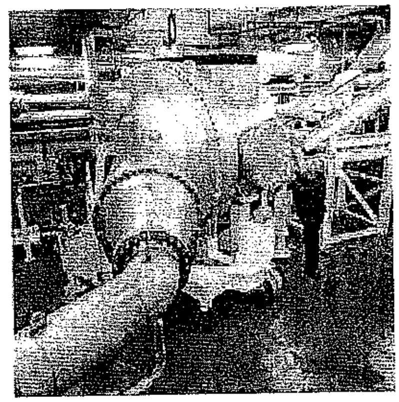
currently underway at an existing power plant, has defined particle size distribution and validated long-term steam filtration. As further validation, specimens duplicating nozzle cooling passages have initiated long-term exposure tests. A separate rotational rig is being used for bucket validation.

The H turbine airfoils have been designed using design data and validation test results for heat transfer, material capability and steam cooling effects. The durability of ceramic thermal barrier coatings has been demonstrated by three different component tests performed by CR&D:

- Furnace cycle test
- Jet engine thermal shock tests
- Electron beam thermal gradient testing

The electron beam thermal gradient test was developed specifically for GEPS to accurately simulate the very high heat transfers and gradients representative of the *H System*™ gas turbine. Heat transfers and gradients representative of the *H System*™ gas turbine have also been proven by field testing of the enhanced coatings in E- and F-class gas turbines.

The stage 1 nozzle, which is the H System™ component subjected to the highest operating temperatures and gradients, has been validated by another intensive component test. A nozzle cascade facility was designed and erected at GEAE (*Figure 19*). It features a turbine segment carrying two closed-loop steam-cooled nozzles downstream from a full-scale H System™ combustor and transition piece. This testing facility accurately provides the actual gas turbine operating environment. Two prototype nozzles complete with pre-spalled TBC were tested in April 1998. Data was obtained validating the aerodynamic design and heat transfer codes. Accelerated endurance test data was also obtained. A second test series, with actual 9H production nozzles, is scheduled to start in the 4th quarter of 2000).



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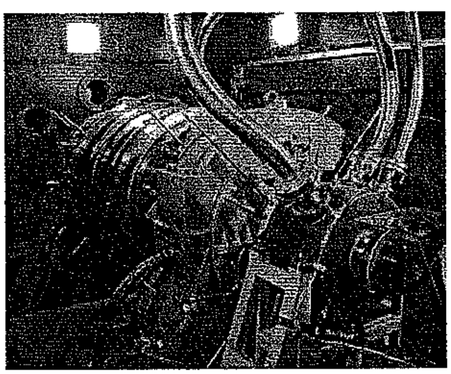

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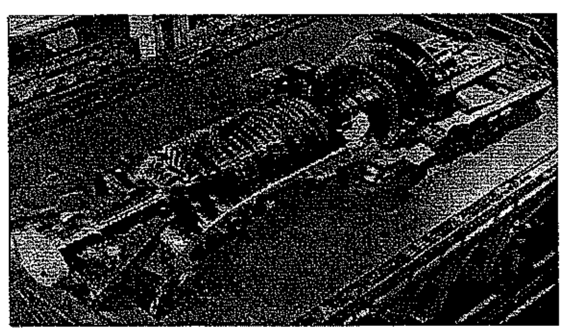

**Figure 21.** 9H gas turbine in half shell prior to first FSNL test

bearings, rotor cooling, cavity temperatures and effectiveness of the clearance control systems.

Following the testing, the gas turbine was disassembled in the factory and measured and scrutinized for signs of wear and tear. The hardware was found to be in excellent condition.

The 9H gas turbine was rebuilt with production turbine airfoils and pre-shipment tests performed in October and November 1999. This unit was fully instrumented for the field test to follow and, thus, incorporated over 3500 gauges and sensors (*Figure 22*).

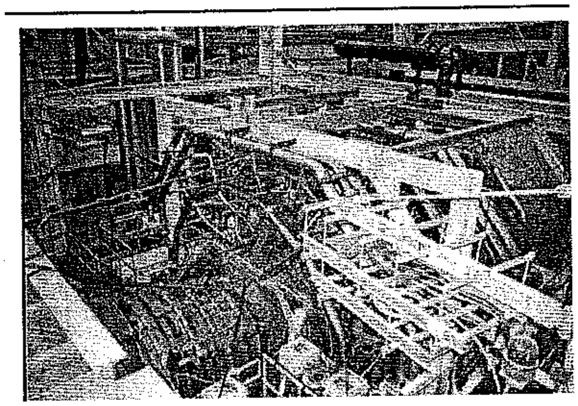

**Figure 22.** 9H gas turbine in test stand for pre-shipment test

This second 9H test series took seven fired starts and verified that the gas turbine was ready to ship to the field for the final validation step. Many firsts were accomplished. The pre-shipment test confirmed that the rotating air/steam cooling system performed as modeled and designed. In particular, leakage, which is critical to the cooling and life of the turbine airfoils and the achievement of well-balanced and predictable rotor behaviors, was well under allowable limits.

Compressor and turbine blade aeromechanics data were obtained at rates of up to 108% of the design speed, clearing the unit to run at design and over-speed conditions. Rotor dynamics were once again demonstrated, and vibration levels were found to be acceptable without field balance weights.

The Mark VI control system demonstrated full control of both the gas turbine and the new *H System*™ accessory and protection systems.

The first 7H gas turbine was assembled and moved to the test stand in December 1999 (*Figure 23*). This 7H went through a test series similar to that for the first 9H factory test. However, the 7H not only covered the 9H test objectives described earlier, but also ran separately with deliberate unbalance at compressor and turbine ends to characterize the rotor sensitivity and vectors. The rotor vibrations showed excellent correlation with the rotor dynamic model and analysis.

The 7H gas turbine is now back in the factory for disassembly and inspection, following the same sequence used for the 9H.

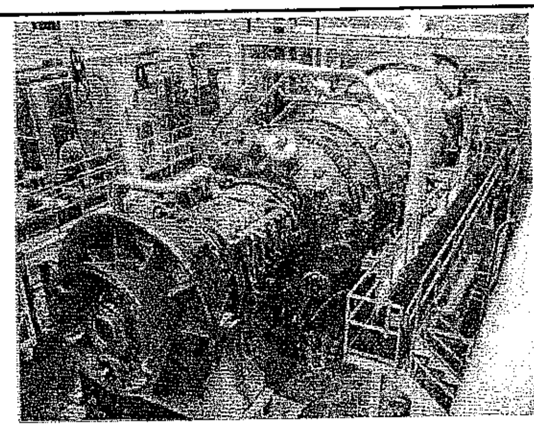

**Figure 23.** 7H gas turbine being installed in test stand

## Validation Summary

GE is utilizing extensive design data and validation test programs to ensure that a reliable *H System*™ power plant is delivered to the customer. A successful baseline compressor test program has validated the *H System*™ compressor design approach. As a result of the 9H and

7H compressor tests, the H compressors have been fully validated for commercial service. The H turbine airfoils have been validated by extensive heat tests, materials testing in steam, TBC testing and steam purity tests. Test results have been integrated into detailed, three-dimensional, aerodynamic, thermal and stress analysis. Full size verification of the stage 1 nozzle design is being achieved through the steam-cooled nozzle cascade testing.

Both 9H and 7H gas turbines have undergone successful factory testing and the 9H is now poised for shipment to the field and final validation test.

## Conclusion

The rigorous design and technology validation of the *H System*™ is an illustration of the GE NPI process in its entirety. It began with a well-reasoned concept that endured a rigorous review and validation process. This ensures the highest probability of success, even before the product or shipping to customers and/or the product has begun operation in the field.

The H technology, combined-cycle power plant creates an entirely new echelon of power generation systems. Its innovative cooling system allows a major increase in firing temperature, which allows the turbine to reach record levels of efficiency and specific work while retaining low emissions capability.

The design for this "next generation" power generation system is now established. Both the 50 Hz and 60 Hz family members are currently in the production and final validation phase. The extensive component test validation program, already well underway, will ensure delivery of a highly reliable, combined-cycle power generation system to the customer.

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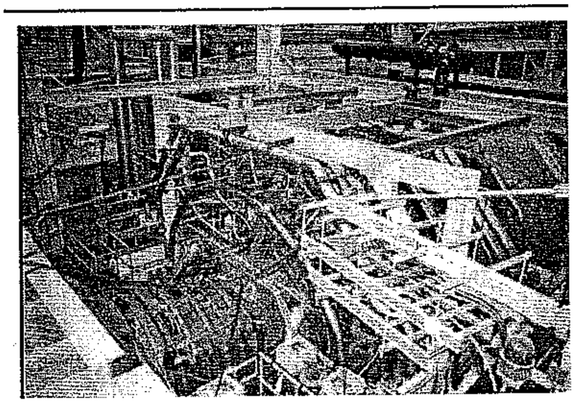

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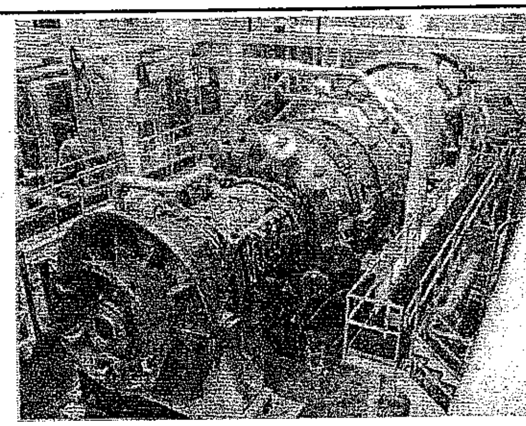

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## List of Figures



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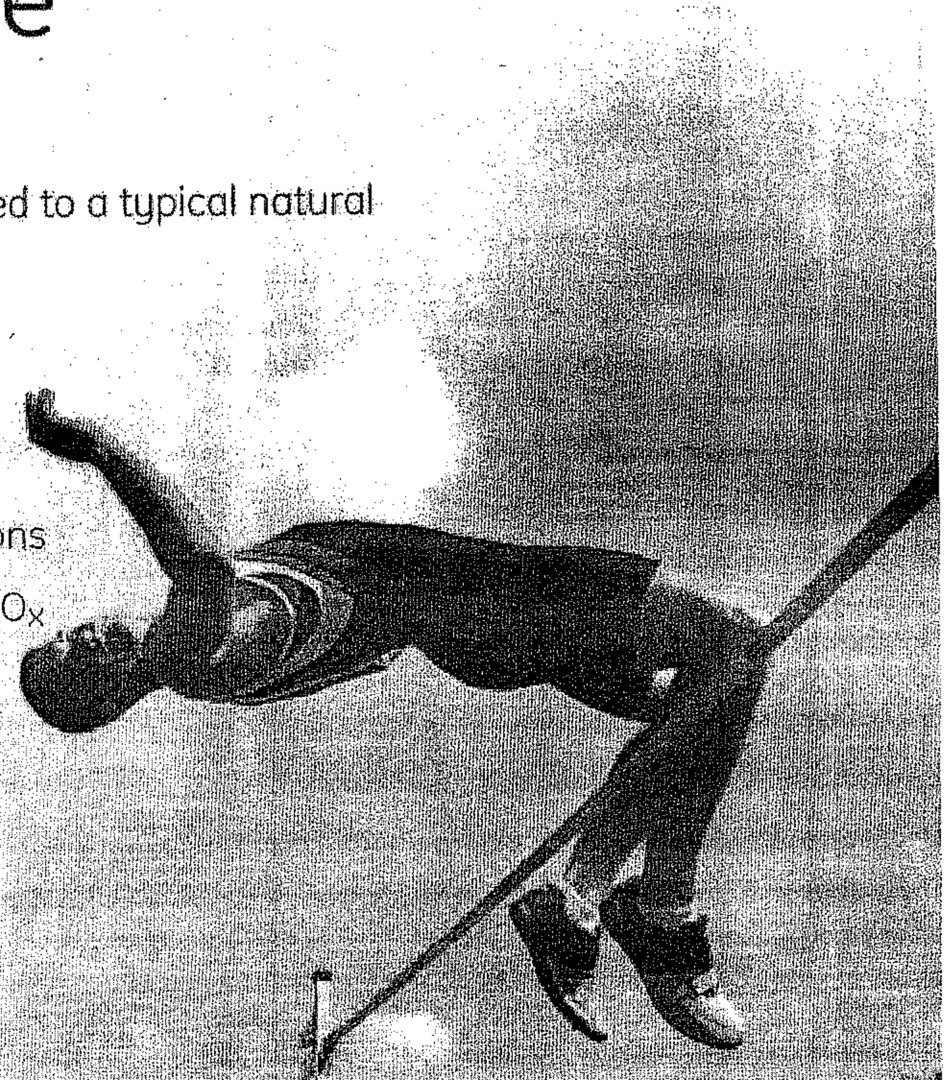
GE Energy

# H System™ – Raising the Bar for Large Combined Cycle

- 9,000 fired hours experience at Baglan Bay
- Lower $NO_x$ and $CO_2$ per unit of electricity when compared to a typical natural gas fired combined cycle power plant
  - New rating: 520MW @ 60% efficiency
- Operational flexibility similar to F Class
  - 50% combined cycle part load operation at ISO
  - 24,000 hour hot gas path; 48,000 hour major inspections
  - 12,000 hour combustion inspection with $30mg/Nm^3$ $NO_x$
  - 60 minute hot start-up time

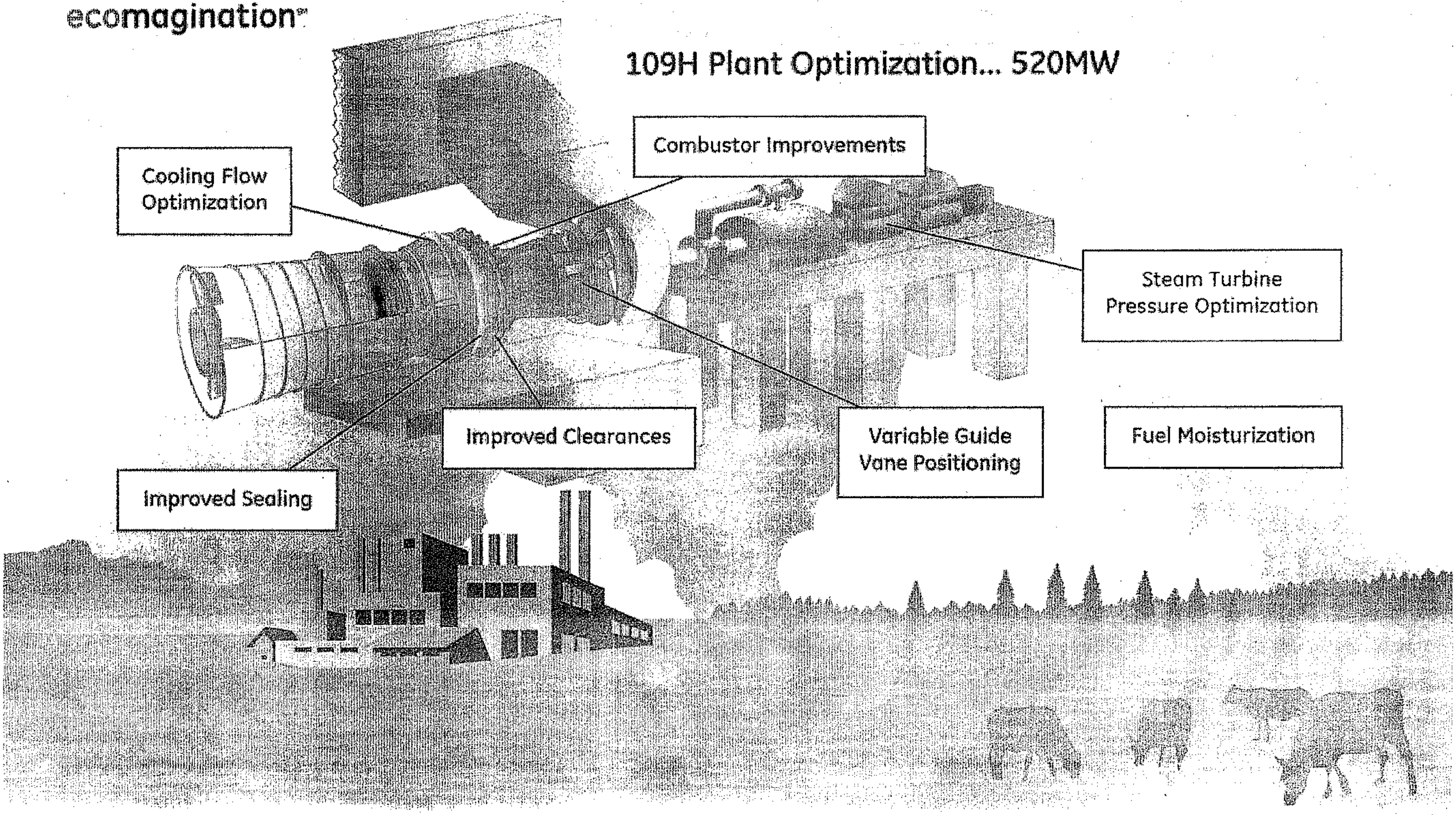


gepower.com

GE imagination at work

a product of
ecomagination℠

# 109H Plant Optimization... 520MW




GE imagination at work

At GE, we believe some of the world's most pressing environmental challenges present an opportunity to do what we do best: imagine and build innovative solutions that benefit our customers and society at large. Ecomagination is our commitment to help solve environmental challenges profitably, today and for generations to come.

GEA-14150 (06/05)

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## Press Release

### GE's H System* Gas Turbine Hits Project Milestone In Japan

*First Firing at TEPCO Plant*

**NEW ORLEANS, LA - December 11, 2007 :** – GE Energy's first commercial H System gas turbi achieved first firing at Tokyo Electric Power Company's Futtsu Thermal Power Station. TEPCO F first commercial site for GE's most advanced, gas turbine combined-cycle system.

Futtsu Thermal Power Station will feature three H Systems, each including GE Energy's 9H gas t with a steam turbine and generator provided by Toshiba under an agreement with GE. The three cycle blocks will enter commercial operation between 2008 and 2010, with a total output of 1,520

"This successful milestone of unit 1 for the Futtsu project is a key step in the commercial develop H System gas turbine," said Steve Bolze, vice president-power generation for GE Energy. "It is a chapter in an on-going relationship with TEPCO, which has been implementing our technology fo years."

With a total production of 60 gigawatts, TEPCO is one of the largest utilities in the world, and is o largest customers. Other TEPCO sites utilizing GE Energy's gas turbine combined-cycle technolc Yokohama, Chiba and Shinagawa.

Futtsu Thermal Power Station marks the second location where GE Energy's H System gas turbi operation. The world's first 50-hertz 9H combined-cycle system entered service in 2003 at Baglar South Wales, and has surpassed 26,500 operating hours. The first 60-hertz project is the Inland I Energy Center in California, scheduled to begin service in 2008.

**H System gas turbine**

The H System gas turbine integrates a gas turbine, steam turbine and heat recovery steam gene GE Energy's most advanced gas turbine combined-cycle system. The technology features an inn closed-loop steam cooling system that allows the turbine to fire at higher temperatures, enabling efficiency, reduced emissions and less fuel consumption per megawatt of power generated.

The H System gas turbine is the industry's first combined-cycle system designed with the capabil achieve 60 percent thermal efficiency, an industry milestone. It also offers 40 percent improveme density per installed megawatt compared to other combined-cycle systems, reducing the overall producing electricity.

The H system gas turbine is capable of producing 87,000 fewer metric tons of greenhouse gases when compared to a typical gas turbine combined-cycle plant generating an equivalent amount o The H System gas turbine is ecomagination certified, a GE product-line certification based on op environmental performance.

* H System gas turbine is a trademark of the General Electric Company.

**About GE Energy**

GE Energy (www.ge.com/energy) is one of the world's leading suppliers of power generation and delivery technologies, with 2006 revenue of $19 billion. Based in Atlanta, Georgia, GE Energy wc areas of the energy industry including coal, oil, natural gas and nuclear energy; renewable resou water, wind, solar and biogas; and other alternative fuels. Numerous GE Energy products are ce

ecomagination, GE's corporate-wide initiative to aggressively bring to market new technologies tl
customers meet pressing environmental challenges.

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## Press Release

**GE'S First 60-Hertz H System* Gas Turbine Project Moves Toward Commercial Startu Year**

*Milestones Mark Progress at Inland Empire Energy Center*

**ATLANTA, GEORGIA - September 10, 2007 :-** The world's first installation of GE Energy's 60-h System* gas turbine, the Inland Empire Energy Center in southern California, remains on target f commercial startup in the summer of 2008.

In a recent project milestone, back feed power was provided to one of the two GE Frame 107H g at the site, clearing the way for startup and commissioning of the power plant auxiliary systems.

A GE-designed demineralization water system is currently being commissioned. This system will demineralized water purified from recycled water feedstock to provide all needed steam plant ma for the entire site operation.

The first 107H gas turbine at the site (unit #1) is expected to achieve first firing by the end of this unit #2 first firing expected in early 2008. Unit #1 will be heavily instrumented and will undergo ex validation testing throughout the first half of 2008, to validate the 107H combined-cycle system.

An innovative, closed-loop steam cooling system and advanced coating materials are key feature System gas turbine's ability to achieve the higher firing temperatures required for increased effici also translates into improved environmental performance. For every unit of electricity generated, System gas turbine uses less fuel and produces fewer greenhouse gases and other emissions w compared to other large gas turbine combined-cycle systems. The H System gas turbine is a key GE ecomagination, a corporate-wide initiative to develop and market technologies that will help c meet pressing environmental challenges.

Operating on natural gas, the two GE 107H combined-cycle systems at Inland Empire will produc 775 megawatts, or enough power to supply nearly 600,000 households. Located in Romoland, ne Riverside, the plant will come on line in the summer of 2008, in time to help offset state-forecaste shortfalls in southern California.

"We're extremely pleased with the progress to date on the Inland Empire project," said John Reir manager of gas turbine and combined-cycle products for GE Energy. "Southern California, with it focus on finding more efficient methods to meet its growing power requirements, is an ideal place showcase our most advanced 60-hertz combined-cycle technology."

GE is financing and will own the Inland Empire Energy Center. Calpine Power Services is manag construction and Calpine Energy Services will market the plant's output and manage fuel requirei a long-term marketing arrangement with GE. Following an extended period of GE ownership, Cal expects to purchase the plant and become its sole owner and operator, with GE continuing to prc maintenance services under a contractual agreement with Calpine.

The 50-hertz version of GE's H System gas turbine made its global commercial debut in 2003 at Bay Power Station in South Wales, where it recently surpassed 24,000 hours of service. The wor installation of 109H technology is Tokyo Electric Power Company's Futtsu Thermal Power Statioi where the first of three 109H combined-cycle systems will enter service in 2008.

**About GE Energy**
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* H System is a trademark of General Electric Company.

# Baglan Bay begins

**It's been 12 years from drawing board to commercial operation, but GE's revolutionary H System gas turbine is now up and running at a combined-cycle plant in Wales. [illegible] visits Baglan Bay.**

The 510MW Baglan Bay power station in Port Talbot, Wales.

Without doubt, the 9H is the most carefully designed, engineered, tested and validated gas turbine in power generation history.

Its specifications also make it the largest, most powerful and efficient such machine in the world. Using the 50Hz 9H or 60Hz 7H turbine, GE's H System combined-cycle configuration is the first capable of breaking the 60 per cent thermal efficiency barrier. The turbine was more than a decade in the making; it finally saw its commercial launch in September at Baglan Bay power plant in the UK (see sidebar page 12).

The higher thermal efficiency of the H System will translate into lower generating costs and less plant emissions. GE estimates that a natural gas-fired CCGT plant using the technology has the capability of realising fuel cost savings of US$2 million a year, compared to existing combined-cycle plant, which operate in the range of 57-58 per cent at best.

The $500m Baglan Bay power station, is built on land leased from BP Chemicals, and provides electricity and process steam to the adjacent Baglan Energy Park and BP's isopropanol plant. Remaining electricity goes to the UK national grid.

Baglan Energy Park is a joint development between BP, Neath Port Talbot County Borough Council and the Welsh Development Agency. The Energy Park currently comprises approximately 200 acres of development land and will feature business and manufacturing facilities. The Baglan Bay redevelopment is the largest single such site in the UK and is made up of several phases, to be developed over the next 20 years.

The availability of clean, low-cost power is expected to play a significant role in attracting new businesses to the park. With the power plant's proximity and high efficiency, businesses in the Energy Park can potentially benefit from up to a 30 per cent saving in electrical costs.

## Development programme

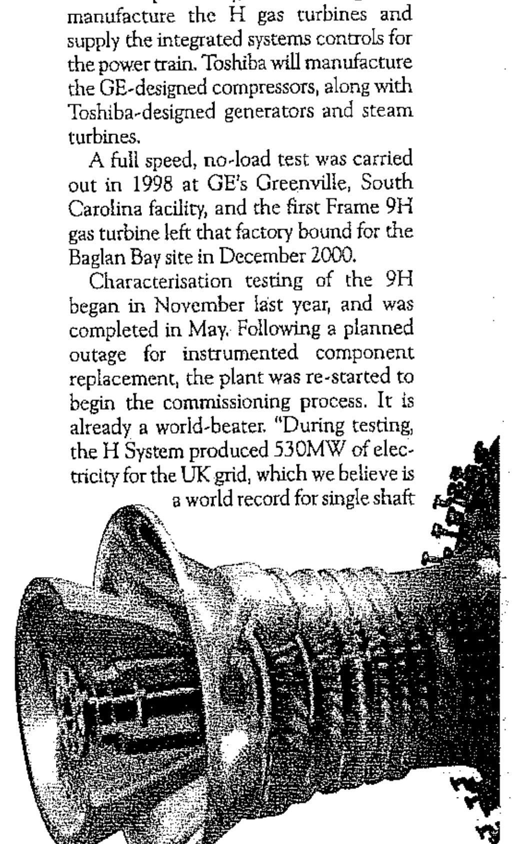
The energy source behind the Park started many years before however. GE engineers produced the H System concept in 1991. It took four years refining the turbine technology before a development programme was announced in 1995.

This was done as part of the US Department of Energy's Advanced Turbine System programme, and included GE Aircraft Engines and the company's Global Research Centre. Two years later the compressor was tested and the first set of single crystal airfoils produced.

Future shipments for the H System will be covered under a previously announced agreement signed by GE and Toshiba of Japan in 1998. Under this agreement, GE has H System integration and performance responsibility, and will design and manufacture the H gas turbines and supply the integrated systems controls for the power train. Toshiba will manufacture the GE-designed compressors, along with Toshiba-designed generators and steam turbines.

A full speed, no-load test was carried out in 1998 at GE's Greenville, South Carolina facility, and the first Frame 9H gas turbine left that factory bound for the Baglan Bay site in December 2000.

Characterisation testing of the 9H began in November last year, and was completed in May. Following a planned outage for instrumented component replacement, the plant was re-started to begin the commissioning process. It is already a world-beater. "During testing, the H System produced 530MW of electricity for the UK grid, which we believe is a world record for single shaft



combined-cycle power generation," says Mark Little, vice-president, Energy Products at GEPS. That recorded output was achieved at site conditions of 7°C, even on a warmer day, the H still produced in excess of 500MW.

The H System integrates gas and steam turbine (single-shaft configuration at Baglan Bay), repressure heat recovery steam generator (HRSG) and 660MVA liquid-cooled generator into one unit, optimising each component's performance. The steam turbine is a D10 three-pressure reheat, single-flow exhaust machine, co-manufactured with Toshiba. Baglan Bay also uses a ten cell cooling tower with low plume, and has its own 2MW diesel generator for black start capability, also used by the CHP plant. The 9H transformer is 22kV, stepped up to 275kV for transmission to the UK national grid.

In addition to the H System, the power station also includes a 33MW combined heat and power plant based on a GE LM2500 gas turbine (see right sidebar).

## World's largest turbine

But it is the gas turbine represents the heart and focus of the project. The 50Hz 480MW-rated Frame 9H gas turbine measures 12 metres long, five meters in diameter; and weighing 370 metric tonnes – it is the largest gas turbine in the world. Much of the H design is based on proven turbine technology.

The compressor system is derivative of GE's Aircraft Engine business, the CF6-80C2 engine (and its aero-derivative LM6000 turbine), a core machine with more than 10 million flight hours.

Building on GE's design experience, the H employs a can-annular lean premix DLN-2.5 dry low NOx (DLN) combustor system. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. It mixes fuel and air prior to ignition to reduce emissions to 25ppm.

This type of combustion system has been proven in millions of hours of operation on other GE gas turbines around the world. It produces more than a million horsepower alone and is the key energy source for the entire plant, including the power turbine, HRSG and steam turbine.

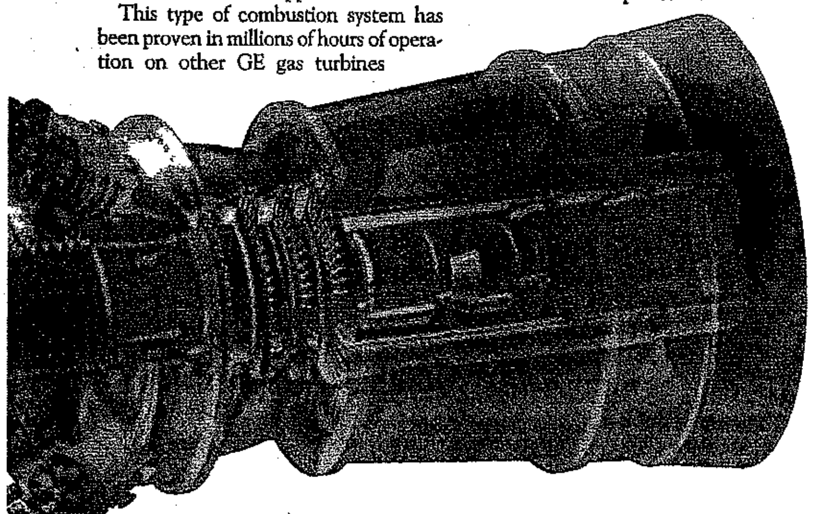
But the revolution so far as gas turbine design is concerned is the firing temperature and cooling system. The 60 per cent plant thermal efficiency is made possible by an increase in gas turbine firing temperature of more than 212°F (100°C) above the most efficient combined-cycle systems currently operating, including GE's own F-technology. Current combined-cycle systems achieve a firing temperature at the gas turbine inlet of around 1,300°C; the new H System increases that to 1,430°C (2,606°F).

This higher firing temperature is made possible by a series of technological advances including the world's largest single crystal airfoils, superior component and coating materials, and an advanced closed-loop steam cooling system.

"It is conditions friendly because the steam cooling in the H System allows the combustion system of the engine to run essentially at the same temperatures as our current F-technology," says Jon Ebacher, vice president of power systems technology at GEPS. "While the turbine inlet is 110°C above that and this is the section that produces power in the gas turbine."

Use of single crystal materials on the first stage nozzles and blades plus the special coatings used ensures that the parts can withstand the high temperatures – temperatures that are significantly higher than the melting point of most metals.

The most critical element of an advanced gas turbine is its hot gas path. The compressor discharge air and fuel are mixed and combusted in a chamber at a specific condition-combustion temperature. The flow stream of high-pressure, high-temperature combustion products is accelerated as it passes through the first stationary airfoil (stage 1 nozzle segment). The firing temperature – the flow stream temperature at the inlet to the first rotational state (stage 1 blade) – establishes the power output. The difference between firing temperature and combustion temperature entering the first stage nozzle is the temperature drop across the stage 1 nozzle.



## The cogeneration plant

The CHP station at Baglan provides steam and electricity to a BP Chemicals process plant, situated close by.

In terms of configuration, the plant is powered by a GE LM2500 aero-derivative gas turbine, with a bypass stack and a heat recovery steam generator on the back end; this is also connected up to a three flue common chimney (for the LM and 9H). "The third flue is for the auxiliary boiler, which provides redundancy for the process steam that is supplied to BP," says Brian Ray, managing director of Baglan Generating Ltd.

The LM2500 also provides the Baglan Bay Power Station (including the H System) with black start capability, so it has its own diesel generator. "Power from the CHP plant is provided not only to BP Chemicals but also to the surrounding Baglan Energy Park," says Ray. "There is still room for expansion; there are a few tenants already in the Energy Park and some more on the way, but at present it's not fully populated."

The CHP plant also provides process cooling for BP Chemicals, so there is a separate two cell cooling tower for that purpose. In addition, an attemperated feedwater line also gives BP that product along with demineralised water from the site's water treatment plant.

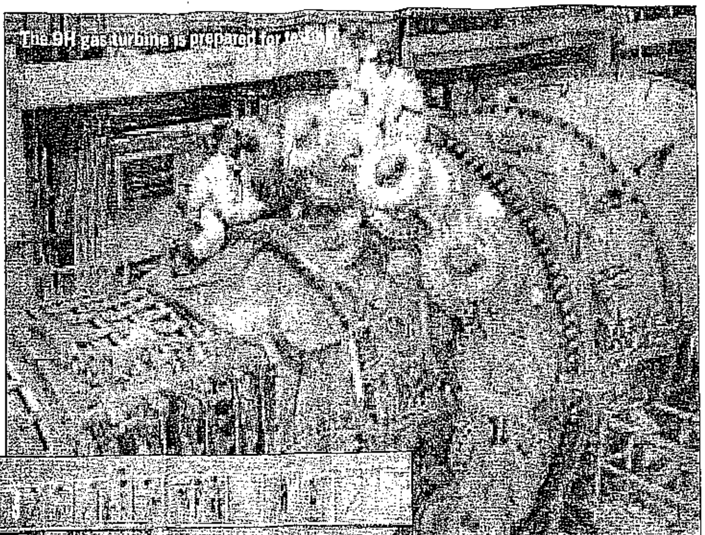
## Cooling process

In current advanced gas turbines, the stage 1 nozzle is cooled with compressor discharge air flowing through the airfoil and discharging out into the combustion gas stream as the airfoil is cooled. The cooling process causes a temperature drop of up to 155°C across the stage 1 nozzle. If the nozzle can be cooled with a closed-loop coolant without film cooling, the temperature drop across the stage 1 nozzle would be less than 44°C, which would permit a 110°C rise in firing temperature with no increase in combustion temperature. That in turn, of course, means no increase in NOx emissions. This is the basis behind GE's steam cooling with the H System.

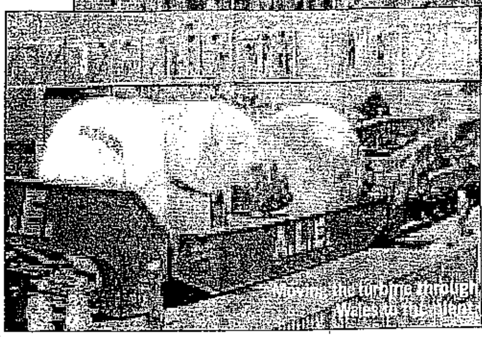
Steam exiting the HP turbine flows through gas turbine blades, nozzles and other parts, cooling them, and simultaneously re-heating the steam before it enters the IP steam turbine.

The steam cooling concept has a dual effect, allowing higher firing temperatures to be achieved without combustion temperature increases and permitting more compressor discharge air to flow to the head-end of the combustor for fuel premixing.

"The benefit is that for about 8 per cent



The 9H gas turbine is prepared for [illegible]



Moving the turbine through Wales to the [illegible]

more airflow than a 50Hz 9F we get 25 per cent more power with similar conditions," says Ebacher. "As the combustor is running at about the same temperature, there's 200°F less drop across the stage 1 nozzle, so as we go into the first stage blade, that generates the real power, 200°F hotter than we do in the F machine, and that's why we get more power.

"We start the machine on air-cooling, waste heat generates steam and at about 10 per cent power we do a transition to steam cooling. When we first looked at this system we knew that the control system would be challenging to make sure that there was no load transients visible to the grid during the transition to steam cooling."

## Most tested turbine

With revolutionary steam cooling capability and the new materials and use of high temperatures, it is little wonder that GE has been extremely cautious with the commercial introduction of the H-technology. The H System represents the most thoroughly tested industrial gas turbine technology in the company's 100-year-plus history. Tests, which involved more than 7,000 sensors placed on the equipment, validated GE's closed-loop steam cooling system.

Following the successful conclusion of the tests, instrumented components used to gather data were replaced with commercial non-instrumented components. The system has been restarted for commercial operation.

The H benefits from four years of extensive testing and design validation," says Mark Little. "From compressor blade tests, combustion tests and launch system integrated control test. Prior to shipping to the Baglan site the 9H gas turbine underwent two full speed no-load tests in the factory, which fully met our design expectations.

"Here at Baglan, GE has undertaken a further five months of full characterisation testing during which time we've validated key technologies at the heart of the H turbine."

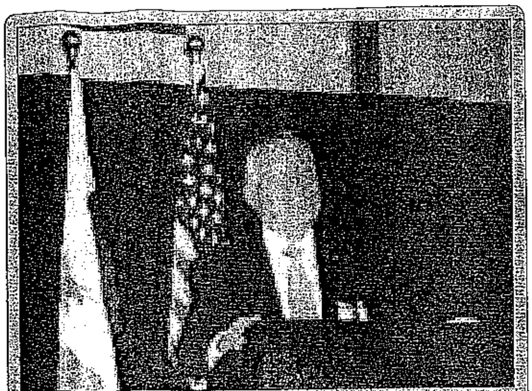
This testing phase encompassed materials, component, subsystem, and system testing of the compressor rigs, as well as tests of the combustion, inlet aero, and Mark VI-based integrated control systems.

## First firing

First firing of the turbine occurred in November, with validation testing lasting until May. Having met its expectations, GE is naturally proud of the new machine's performance. "As anyone involved in commissioning combined-cycle plant knows it is a difficult process," says Don Hoffmann, H System product line manager.

"Since first firing in November 2002, we've had 29 start attempts and everyone of those has been successful, no failures at all." And after 12 years of design, engineering and testing commercial launch of the Baglan Bay CCGT plant took place in September.

The H System gas turbine plant has been the most eagerly awaited project for many years. On its launch GE executives and UK politicians lauded the technology. Known for its caution and procrastination, the power industry as a whole will watch with close interest the performance of the turbine at Baglan. IPG



# The plant launch

Over 200 customers, executives, politicians, invited guests and media were in South Wales in September for the launch of the Baglan Bay project.

The opening conference was addressed by the Secretary of State for Wales, Peter Hain, plus John Rice, GE Power Systems president and CEO, and local Welsh politicians. Hain brought a stark note of reality to the event, "I have noticed that GE's turnover is bigger than the entire Welsh budget!

"Within two years UK gas imports will outstrip its production making it imperative that there is an efficient use of gas. The 9H CCGT plant is capable of 60 per cent efficiency compared to 21-39 per cent for coal-fired power stations, and produces 30 per cent less carbon emissions than a typical coal plant."

These words were eagerly echoed by GE's ensemble of executives. "We have much to celebrate," said Del Williamson, GEPS president of global sales. "This H System is a new technology platform that significantly advances large-scale power generation."

Rice spoke about the teamwork that went into the H System and Baglan Bay, "I can't be prouder of the team that brought the H System to life. In truth, this is a total team effort spanning a multitude of companies, countries and political bodies."

But it didn't entirely go to plan. A couple of days before the launch there was an alarm indicating a localised temperature increase that caused the unit to be taken offline.

As part of the recommissioning process GE found that there were three turbine blades out of 120, in one section, that appear to have restricted steam flow. "That was not present in the earlier testing but it is being addressed and the machine will run again and produce those high powers," said Jon Ebacher, vice president of power systems technology at GEPS.

Subsequent thorough inspection of the stage two blades re-confirmed that the elevated temperature was the result of a localised cooling flow restriction caused by foreign material collecting in the steam cooling path during the supplier's manufacturing process.

The milestone 60 per cent thermal efficiency figure was not realised at Baglan. GE's prime purpose here has been to run and validate the gas turbine technology.

Also announced at the September launch was that GE expects to begin offering the H System as a commercial product beginning in the last quarter of this year. It already has an order from TEPCO to supply three 109H systems for a project in Japan. Meanwhile GE is actively looking for a launch site for its 60Hz 7H gas turbine.

GE Energy



# H System Launch Site



**Baglan Bay Power Station Port Talbot, Wales***
100% GE-owned investment in validation of the revolutionary technology and turnkey construction-comprised of two power

View the 9H photo gallery

**Features**

**109H System Combined Cycle Power Plant**

- 480 MW; single shaft; 60% CC efficiency platform
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; $NO_x$ emissions: 25 ppm

**Steam Turbine:** GE design; reheat, single flow exhaust; co-mfg. with Toshiba
**Generator:** GE 550 MW LSTG; 660 MVA liquid cooled
**HRSG:** 3 pressure level reheat

**LM2500 Combined Heat and Power Plant**

- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park** and BP Chemical Plant*** - electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

**Other Baglan PowerStation Features**

- GE Mark VI based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies treatment plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to BP Chemicals and Baglan Energy Park
- Pipeline Reception Facility (PRF)
  - For 12 km Baglan pipeline spur to National Transmission (Gas) System
  - Gas compression and pressure reduction capability, featuring GE centrifugal compressors

**GE Products & Services Used at Baglan**

**Download More Informat**

- Article Reprint from Interr Power Generation: "Bagl Begins" (344KB PDF)
- H System: The World's M Advanced Combined Cyc Technology Brochure (98 PDF)
- Power Systems for the 2 Century: "H" Gas Turbine Combined Cycles (252KE
- MPG Video: H System: W Most Advanced Combine Gas Turbine (19MB ZIP)

**GE**
- 9H gas turbine, LP steam turbine, generator, other power train equipment and accessories
- EPC project management
- Technical advisors
- Operations & maintenance; monitoring and diagnostics
- LM2500, plant compressors, gas compressors
- Water treatment systems
- 2 MW diesel generator
- Construction and testing power (GE Rentals)
- Switchyard control system; GT instruments
- BOP PLCs and operator interfaces
- Plant-merchant systems integration software

**GE Capital**
- IT integration support
- Plant financing

**GE Industrial Systems**
- Integrated control system with Mark VIs
- 6.9 kV switchgear
- Various pump and valve motors

**GE Lighting**
- Turbine hall and BOP lighting

**Silvertech**
- PRF control systems integration

**Penpower**
- Commissioning

**QCI**
- Pipe installation technical advisors

* Plant located on site leased from BP

** Baglan Energy Park is a joint development among BP, Welsh Development Agency and Neal Talbot County Borough Council

*** BP Chemicals Limited - Isopropanol plant adjacent to power station

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# Attachment
# E

# WESTINGHOUSE'S ADVANCED TURBINE SYSTEMS PROGRAM

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## ABSTRACT

The paper describes the goals of the Westinghouse Advanced Turbine Systems program. This program is being undertaken in response to the DOE Fossil Energy requirements for improved efficiency, lower cost of electricity, lower emissions, and state-of-the-art reliability levels.

It describes in detail the objectives of the program and the approach taken by Westinghouse to achieve those goals. The evolutionary approach taken by Westinghouse is explained together with the development program and component testing undertaken in the last year.

The benefits of this new advanced turbine are discussed and the future activities of the program are explained.

## INTRODUCTION

U.S. Department of Energy, Office of Fossil Energy Advanced Turbine Systems Program is a multi-year effort to develop the necessary technologies, which will result in a significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity and a decrease in harmful emissions. In Phase 1 of the ATS Program, preliminary investigations on different gas turbine cycles demonstrated that net plant efficiency greater than 60% is achievable. The more promising cycles were evaluated in greater detail in Phase 2 and the closed-loop cooled combined cycle was selected because it offered the best solution with the least risk for achieving the ATS Program goals of net plant efficiency, emissions, cost of electricity, reliability-availability-maintainability (RAM), as well as commercial operation by the year 2000.

The Westinghouse ATS plant is based on an enhanced technology gas turbine design combined with an advanced steam turbine and a high efficiency generator. To meet the challenging performance, emissions, and RAM goals, existing technologies were extended and new technologies developed. The attainment of ATS performance goal necessitated advancements in aerodynamics, sealing, cooling, coatings, and materials technologies. To reduce emissions to the required levels, demanded a development effort in the following combustion technology areas: lean premixed ultra-low NOx combustion, catalytic combustion, combustion instabilities, and optical diagnostics. To achieve the RAM targets, required the utilization of proven design features, with quantified risk analysis, and advanced materials, coatings, and cooling technologies.

The 501ATS engine is the next frame in the series of successful utility turbines developed by Westinghouse over the last 50 years. During that time, Westinghouse engineers made significant contributions in advancing gas turbine technology as applied to heavy-duty industrial and utility engines. Some of the innovations included single-shaft two-bearing engine design, cold-end drive, axial exhaust, first cooled turbine airfoils in an industrial engine, and tilting pad bearings, features which all major gas turbine manufacturers have incorporated in their designs. The evolution of large gas turbines started at Westinghouse with the introduction of the 45 MW 501A engine in 1968 (see Table 1). Continuous enhancements in performance were made up to the 100 MW 501D5 introduced in 1981. The next engine was the 160 MW 501F introduced in 1991. The 230 MW 501G was next in the series and is the initial step in ATS engine development. Each successive engine design was based on the proven concepts used in the previous design.

The 501F was introduced at 160 MW and a simple cycle efficiency of 36%. Its current uprated rating is 167 MW and its combined cycle net efficiency is greater than 55%. The first four 501F engines that entered service with Florida Power and Light have demonstrated 99% reliability and 94% availability in over 33,000 operating hours each.

The 501G produces 230 MW in simple cycle and its combined cycle net efficiency is 58%. This engine incorporates further advancements in materials, cooling technology, and component aerodynamic design. The 19:1 pressure ratio compressor uses advanced profile high efficiency airfoils. The combustion system incorporates 16 dry low NOx combustors, with similar flame temperature as in the 501F, and hence, the same low emissions. This was made possible by the closed-loop steam cooled transition design, which eliminated transition cooling air ejection into the gas path. The four-stage 501G turbine uses full 3-D design airfoils and proven aeroderivative materials and coatings.

Westinghouse's strategy to achieve, and exceed, the ATS Program goals is to build on the proven technologies used in the successfully operating fleet of its utility gas turbines, such as the 501F, and to extend the technologies developed for the 501G.

**ATS DESCRIPTION**

The ATS plant consists of the gas turbine, generator, and steam turbine, connected together in an in-line arrangement with a clutch located between the generator and the steam turbine. The gas turbine exhaust gases produce steam in the three-pressure level heat recovery steam generator. The high pressure steam turbine exhaust steam is used to cool the transitions and two rows of stators. The reheated steam is then returned to the steam cycle for induction into the intermediate pressure steam turbine.

The ATS engine is a state-of-the-art 300 MW class design incorporating many proven design features used in previous Westinghouse gas turbines and new design features and technologies required to achieve the ATS Program goals.

## Compressor

The compressor shares many common parts with the 501G 16-stage compressor. The mass flow is identical, but the ATS higher rotor inlet temperature and closed-loop cooling has required an increase in pressure ratio from 19:1 to 29:1. This increased pressure ratio was achieved by adding stages to the rear of the 501G compressor. The latest 3-D viscous codes and custom-designed airfoils were used in the compressor aerodynamic design. Variable stators have been added to stages 1 and 2 to improve starting capability and part-load performance.

## Combustion System

The 501ATS incorporates 16 combustors based on the lean premixed multi-stage piloted ring design. The burner outlet temperature was kept at the same level as in the 501F and 501G, by using closed-loop steam cooling (with air as an alternate coolant) in the transitions and turbine stators, so that more compressor delivery air was available in the combustor head end. Therefore, this allowed very lean, premixed combustion and hence single digit NOx emissions.

To aid in ATS combustor design and development, extensive use was made of computational fluid dynamics (CFD) analysis. Using CFD analysis expedited combustion system development and allowed screening of modifications prior to testing. This resulted in combustors with more predictable performance and reliability.

## Turbine

The four-stage turbine design was based on 3-D design philosophy and viscous analysis codes. The airfoil loadings were optimized to enhance aerodynamic performance while minimizing airfoil solidity. The reduced solidity resulted in lower cooling requirements and increased efficiency. To further enhance plant efficiency, the following features were included: turbine airfoil closed-loop cooling, active blade tip clearance control on the first two stages, improved rotor sealing, and optimum circumferential alignment of airfoils.

The ATS engine utilized advanced thin wall designs with thermal barrier coatings and the state-of-the-art aero engine cooling technology. The first and second stage vanes used closed-loop steam cooling and the first two stages of blades used closed-loop air cooling. Air was chosen for blade cooling because it does not have the risks of steam corrosion, deposition, and complexity that closed-loop cooling with steam poses. In addition, the air can be cooled after it is removed from the combustor shell so that only relatively small amounts of cooling air are needed for the rotor. The cooling air is filtered to remove dirt particles before being ducted to the rotor blades. The difference in plant thermal efficiency between blade closed-loop cooling by air instead of steam is about 0.2%. Thus, based on a cost benefit analysis and RAM analysis, closed-loop air cooling is the preferred approach.

Westinghouse has been using thermal barrier coatings (TBC) on turbine airfoils since 1986 and has built an extensive experience base. It is a standard "bill of material" for new 501D5, 501F, and 251B11/12 engines. Recent field trials have demonstrated excellent results after operation for 24,000 hours. In the 501ATS engine, further improvements in TBC coating, with improved bond coats and new ceramic materials, will be utilized.

The 501ATS turbine design used the latest aero engine blade and vane nickel-based alloys. Single crystal nickel alloy, CMSX-4, was employed on the first stage vanes and blades to provide increased creep strength and fatigue resistance compared to conventional materials.

**Rotor Design**

The power level transmitted through the rotor and the resulting high stresses make rotor design an extremely important component of the engine. The 501ATS rotor consists of four ruggedized alloy steel discs clamped together with 12 through-bolts. Alloy steel was used to extend the excellent past operating experience with this material to the ATS engine and to reduce engine cost. In this design, torque transmission and alignment are achieved by the use of a Curvic™ clutch, which is a beveled male and female tooth form. This design has been proven by use on all Westinghouse-designed gas turbines over the past 40 years.

During the rotor design process, extensive finite element analysis modeling was carried out to calculate rotor critical speeds and cyclic life. In order to ensure rotor stability, a transient analysis from startup to baseload was carried out to verify that there was no slipping or gapping of the torque carrying members. The analysis has demonstrated that during all conditions analyzed, the torque carrying Curvic™ clutch arms do not come out of engagement. This virtually eliminates frettage or slippage which could give rise to vibration or cracking.

The compressor rotor is a series of discs clamped together with 12 through-bolts. However, the torque transmission is via friction and radial keys between all discs. This method was also used on the 501F and shown to be reliable. Alignment of the discs is maintained by a spigot at the base of the discs and by the shoulder on the radial pins. Computer modeling was used to ensure the rotor stability over its complete operating range with no chance of slippage or gapping.

## TECHNOLOGY VERIFICATION PROGRAMS

To ensure that ATS program goals are achieved, an extensive technology verification program is in progress in the following areas: combustion, cooling, aerodynamics, leakage control, coatings, and materials.

## Combustion

The 501ATS piloted ring combustor is the most successful candidate of combustors developed by Westinghouse over the past 10 years. It consists of a pilot and two separate premixed zones arranged axially, the primary and secondary zones. Premixed fuel and air enter the primary zone where combustion is stabilized by a swirl-produced recirculation zone and a centrally located pilot. The second zone is located downstream and is fed premixed fuel and air through an annular passage surrounding the primary zone. This combustor, which achieved single digit NOx emissions and excellent stability on low pressure tests, is currently undergoing evaluation at high pressures.

## Cooling

Elimination of cooling air injection into the turbine flow path, as a result of closed-loop steam cooling, is the major contributor to the increase in ATS plant efficiency. This results in an increase in gas temperature downstream of the first stage vane and hence an increase in gas energy level during the expansion process. A secondary contributor is the elimination of mixing losses associated with cooling air ejection. The combination of these effects results in a significant increase in ATS plant efficiency. In addition, NOx emissions are reduced because more air is available for the lean premixed combustor at the same burner outlet temperature. Achieving acceptable blade metal temperatures in a closed-loop cooling design is a challenge due to the absence of a cooling air film to shield the turbine airfoil and shroud wall, and no shower-head or trailing edge ejection to provide enhanced cooling in the critical leading and trailing edge regions. To produce an optimized closed-loop cooling design, the following approaches were utilized: (1) airfoil aerodynamic design tailored to provide minimum gas side heat transfer coefficients, (2) minimum coolant inlet temperature, (3) thermal barrier coating applied on airfoil and end wall surfaces to reduce heat input, (4) maximized cold side surface area, (5) turbulators to enhance cold side heat transfer coefficients, and (6) minimum outside wall thicknesses to reduce wall temperature gradients and hence the internal heat transfer coefficients required to cool the airfoil.

The thin-wall closed-loop cooled first stage vane and blade design was completed and casting development started at Allison-Single Crystal Operations. To verify the critical cooling designs, a three part program was undertaken. The internal heat transfer coefficients and pressure drops are being measured on plastic models of the different vane and blade cooling features at Carnegie Mellon University. A liquid crystal thermochromic paint technique was used to measure the internal heat transfer coefficients. The outside heat transfer coefficients will be measured on model turbine tests. The first stage vane cooling design will be verified at ATS operating conditions in a hot cascade test rig in the Westinghouse high pressure combustion test facility located at the Arnold Engineering Development Center, in Arnold AFB, Tennessee.

## Compressor Aerodynamics Development

To determine its performance and operating characteristics over the complete operating range, the full-scale ATS compressor was tested in a specially designed facility located at the

U.S. Navy Base in Philadelphia. The facility was designed for subatmospheric inlet pressure to reduce the power required to drive the compressor. The inlet system consisted of a filter house, straight pipe with a flow straightener and a flow meter, inlet throttle valve, diffuser with flow straightening devices, 90° bend with turning vanes, and a silencer. Because of the subatmoshperic operation, two stages of compressor bleed air were ducted into the inlet diffuser, after passing through coolers. The exhaust system included a large diameter back pressure valve to provide control on the test pressure ratio. A small diameter quick-acting valve, located in a bypass line around the large back pressure valve, was used for recovery from compressor surge.

The compressor was instrumented with static pressure taps, fixed temperature and pressure rakes, thermocouples, tip clearance probes, blade vibration monitoring probes, rotor vibration probes, acoustic probes, and strain gauges. Provisions were made for radial traverses in eight axial locations in the compressor and four radial locations in the inlet duct. More than 500 individual measurements were recorded. A dedicated data acquisition system was used to collect and reduce the test data. Important performance and health monitoring parameters were displayed on computer screens in real time. After the compressor test facility was commissioned, an extensive test program was performed. The test program included design point performance verification, blade vibration and diaphragm strain gauge measurements, inlet guide vane and variable stator optimization, compressor map definition and starting characteristics optimization.

## Turbine Aerodynamic Development

The first two 501ATS turbine stages will be tested at 1/3-scale in a model turbine test rig, located at Ohio State University, to verify aerodynamic performance with reduced airfoil solidity, to quantify performance benefits due to optimum circumferential alignment of turbine airfoils, and to measure outside heat transfer coefficients on the airfoils of this advanced 3-D aero design turbine. The model turbine component manufacture was completed. Pressure sensor and thermocouple installation on the model turbine airfoils was also completed. The heat flux gauge installation is nearing completion. The test facility, which was moved from Buffalo to Ohio State University, was commissioned and is ready for model turbine testing.

## Leakage Control

To reduce air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals were incorporated under the compressor diaphragms, turbine disc front, turbine rim, and turbine interstage locations. A development program was initiated to incorporate an effective, reliable, and long-lasting brush seal system into a heavy-duty industrial gas turbine. Tests were performed to select the appropriate bristle materials, to quantify wear characteristics and to determine leakage. The brush seal performance under the compressor diaphragms was verified during the 501ATS compressor testing. To test their performance over long operating times, turbine interstage seals were installed on a new 501F engine and will be retrofitted into 501D5 engines.

A face seal was designed to prevent rotor cooling air leakage as it is introduced at the rotor rear. Seal hardware has been ordered and a test rig is being constructed. Tests will be carried out to verify the face seal performance.

### Coatings

The ATS engine turbine component coatings must be capable of operation for 24,000 hours. To ensure this, a program is in progress to develop an improved bond coat/TBC system. Different bond coats are being evaluated under accelerated oxidation test conditions. New ceramic candidate materials are also undergoing testing. The objective of this program is to combine the optimum bond coat with the best performing TBC to provide a coating system with maximum service life at the ATS operating conditions. An advanced bond coat/TBC system has accumulated more than 20,000 hours in cyclic testing at 1010°C (1850°F) with excellent results.

### Materials

To enhance performance and reliability, single crystal (SC) blades are used in the ATS engine. A casting development program was carried out to demonstrate castability of large industrial turbine blades in CMSX-4 material. Existing 501F engine tooling was used to cast single crystal blades. The castings were evaluated by grain etching, selected NDE methods and dimensional inspection methods to determine their metallurgical acceptability. After several trials, excellent results were obtained on a solid and a cored blade thus demonstrating that SC blades are castable in CMSX-4 alloy. Further process development is in progress to optimize post-cast heat treatment, evaluate effects of grain defects, generate SC material design data, and further develop the casting process.

## FUTURE ACTIVITIES

Technology development efforts to date have demonstrated that ATS Program goals are obtainable. The results have been incorporated into the 501ATS design. Future ATS Phase 3 activities will complete the technology verification process. High pressure testing on the ATS piloted ring combustor will be carried out to optimize the design and demonstrate single digit NOx emissions. Catalytic combustion development will proceed toward full-scale testing of catalytic combustor by the end of the year. The two-stage model turbine tests, to verify aerodynamic performance and to measure outside heat transfer coefficients, will be completed. Rig testing will be completed on the turbine brush seals and rotor face seal. Abradability tests will be carried out on the turbine blade tip treatments, which will be applied to blade tips for wear protection. Pre-production casting development will continue on the single crystal thin wall stage 1 vanes and blades and thick wall stage 2 blades. Long term verification tests on advanced bond coat/TBC system will be carried out on test rigs and rainbow tests with coated blades on operating engines. The next phase of the ATS Program includes building the prototype 501ATS engine and carrying out extensive testing to verify its performance and mechanical integrity.

## ACKNOWLEDGMENTS

The research discussed in this paper is sponsored by the U.S. Department of Energy's Federal Energy Technology Center (FETC), under Contract DE-FC21-95MC32267 with Westinghouse Electric Corporation, 4400 Alafaya Trail, Orlando, Florida 32826-2399; telefax 407-281-5633. The period of performance is from September 1995 to December 1997. This program is administered under the guidance of FETC's Program Manager, Dr. Richard A. Johnson.

| Engine | 501A | 501B | 501D | 501D5 | 501D5A | 501F | 501G | 501/ATS |
|---|---|---|---|---|---|---|---|---|
| Commercial Operation | 1968 | 1973 | 1976 | 1982 | 1994 | 1993 | 1997 | 2000 |
| Power, MW | 45 | 80 | 95 | 107 | 120 | 160 | 230 | 420* |
| Rotor Inlet Temp.,°F | 1615 | 1819 | 2005 | 2070 | 2150 | 2330 | 2583 | 2750 |
| Air Flow, Lb/Sec | 548 | 746 | 781 | 790 | 832 | 961 | 1200 | 1200 |
| Pressure Ratio | 7:5 | 11:2 | 12:6 | 14:1 | 15:1 | 15:1 | 19:1 | 29:1 |
| No. Comp. Stages | 17 | 17 | 19 | 19 | 19 | 16 | 16 | 20 |
| No. Turbine Stages | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| No. Cooled Rows | 1 | 3 | 4 | 4 | 4 | 6 | 6 | 6 |
| Exhaust Temp., °F | 885 | 907 | 956 | 981 | 1004 | 1083 | 1100 | 1100 |
| Heat Rate (Btu/kWh)<br>Simple<br>Combined | <br>12,600<br>9,000 | <br>11,600<br>7,350 | <br>10,925<br>7,280 | <br>10,040<br>7,055 | <br>9,900<br>7,024 | <br>9,610<br>6,429 | <br>8,860<br>5,881 | <br>--<br>5,686 |

*Combined cycle output power

# Attachment
# F

# Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Linda S. Adams
*Secretary for Environmental Protection*

Arnold Schwarzenegger
*Governor*

December 17, 2007

Mr. Wayne Nastri
Regional Administrator
Region 9
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, California 94105-3901

Dear Mr. Nastri:

We are transmitting our recommendations for area designations and boundaries under the federal air quality standards for particulate matter 2.5 microns or less in diameter (PM2.5) as requested in your July 10, 2007 letter to Governor Schwarzenegger.

**PM2.5 Nonattainment Areas**

We base our recommendations on ambient PM2.5 concentrations measured from 2004 through 2006 by 81 Federal Reference Method (FRM) monitors located throughout California. The Air Resources Board's (ARB) recommendation is that the U.S. Environmental Protection Agency (U.S. EPA) designate seven areas as nonattainment for the revised PM2.5 24-hour standard:

- South Coast Air Basin.
- San Joaquin Valley Air Basin.
- Bay Area Air Quality Management District.
- Sacramento Metropolitan Air Quality Management District.
- The combined cities of Yuba City/Marysville within the Feather River Air Quality Management District.
- The City of Chico within the Butte County Air Quality Management District.
- The City if Calexico within the Imperial County Air Pollution Control District.

We also recommend that U.S. EPA designate twelve areas as attainment, where air quality data are sufficient to determine that they meet the federal standard. Finally, 28 areas should be deemed unclassifiable, where air quality data are insufficient to make a determination.

**Nonattainment Area Boundaries**
Regarding nonattainment area boundaries, ARB staff has the following recommendations:

- Retaining the existing nonattainment area boundaries for South Coast and San Joaquin Valley.
- Establishing nonattainment area boundaries for the Bay Area and Sacramento consistent with the air district boundary for each region.
- Establishing focused nonattainment areas for the cities of Chico, and the combined cities of Marysville and Yuba City to reflect the localized nature of the PM2.5 problem in these regions.

We also recommend a focused nonattainment area for the city of Calexico. ARB staff believes that violations of the daily PM2.5 standard in Calexico during the 2004 – 2006 period result from emissions in the densely populated city of Mexicali across the border. We believe that the City of Calexico would attain the PM2.5 air quality standard but for emissions emanating from outside of the United States. ARB plans to use the provisions in the Clean Air Act for dealing with air quality problems along international border areas.

**Enclosures**
We include the following materials in this package:

- Recommended nonattainment/attainment/unclassifiable areas (Enclosure 1).
- Staff Report (Enclosure 2).
- Information supporting recommendations for nonattainment areas (Enclosure 3).
- Boundary descriptions (Enclosure 4).
- 2004 – 2006 data for all of California's PM2.5 monitoring sites (Enclosure 5).

If you have any questions, please call Lynn Terry, Deputy Executive Officer, at (916) 322-2739, or have your staff contact Karen Magliano, Chief, Air Quality Data Branch, at (916) 322-7137.

Sincerely,

***Original signed by***

James N. Goldstene
Executive Officer

Enclosures

cc: See next page.

cc: Stephen Birdsall, APCO
Imperial County Air Pollution Control District
150 South 9th Street
El Centro, California 92243

Jack Broadbent, APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, California 94109-7799

Larry Green, APCO
Sacramento Metropolitan Air Quality Management District
777 12th Street, Third Floor
Sacramento, California 95814-1908

Seyed Sadredin, APCO
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg
Fresno, California 93736

Dave Valler, APCO
Feather River Air Quality Management District
938 14th Street
Marysville, California 95901-4149

W. James Wagoner, APCO
Butte County Air Quality Management District
2525 Dominic Drive, Suite J
Chico, California 95928-7184

Barry Wallerstein, APCO
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, California 91765-4182

Lynn Terry
Air Resources Board

Karen Magliano
Air Resources Board

## Enclosure 1

### State of California
### Initial Recommendations for Area Designations under the Revised Federal PM2.5 Standard

(based on 2004 – 2006 monitoring data)

| Recommended PM2.5 Nonattainment Areas in California | | | |
|---|---|---|---|
| **Nonattainment Area** | **24-Hour Design Value** | **High Monitor Location** | **Areas Included** |
| South Coast Air Basin | 57 | Riverside County – Rubidoux | Western Los Angeles, Orange, Southwestern San Bernardino, and Western Riverside Counties |
| San Joaquin Valley Air Basin | 64 | Kern County – Bakersfield | San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulare, and Western Kern Counties |
| San Francisco Bay Area | 39 | Santa Clara County - San Jose | Southern Sonoma, Napa, Marin, San Francisco, Contra Costa, Alameda, Santa Clara, San Mateo, and Western Solano Counties |
| Sacramento Metropolitan Air District | 49 | Sacramento County – Del Paso Manor | Sacramento County |
| City of Calexico | 40 | Imperial County Calexico – Ethel St. | City of Calexico |
| Combined Cities of Marysville and Yuba City | 40 | Sutter County – Yuba City | Cities of Marysville and Yuba City |
| City of Chico | 56 | Butte County - Chico | City of Chico |

| Recommended PM2.5 Attainment Areas in California | | | |
|---|---|---|---|
| **Attainment Area** | **24-Hour Design Value** | **High Monitor Location** | **Areas included** |
| Calaveras County | 21 | San Andreas | Calaveras County |
| Imperial County | 25 | El Centro | Imperial County excluding the recommended Calexico nonattainment area |
| Colusa County | 27 | Colusa | Colusa County |
| Shasta County | 22 | Redding | Shasta County |
| Plumas County | 30 | Portola | Plumas County |
| Mendocino County | 16 | Ukiah | Mendocino County |
| Lake County | 14 | Lakeport | Lake County |
| Nevada County | 16 | Truckee | Nevada County |
| Placer County | 31 | Roseville | Placer County |
| Yolo/Solano Air District | 30 | Woodland | Yolo and Eastern Solano Counties |
| Ventura County | 30 | Simi Valley | Ventura County |
| San Diego County | 28 | Chula Vista | San Diego County |

| Recommended PM2.5 Unclassifiable Areas in California |
|---|
| Butte County (excluding the recommended nonattainment area for the city of Chico) |
| Sutter County (excluding the recommended nonattainment area for the combined cities of Marysville and Yuba City) |
| Yuba County (excluding the recommended nonattainment area for the combined cities of Marysville and Yuba City) |
| Alpine County |
| Glenn County |
| Humboldt County |
| Del Norte County |
| El Dorado County |
| Inyo County |
| Lassen County |
| Mariposa County |
| Monterey County |
| Modoc County |
| Mono County |
| San Benito County |
| Santa Cruz County |
| San Luis Obispo County |
| Santa Barbara County |
| Siskiyou County |
| Sierra County |
| Tehama County |
| Trinity County |
| Tuolumne County |
| Amador County |
| Eastern Kern County |
| Northern Sonoma County |
| Eastern Los Angeles County |
| Eastern Riverside County |
| Northeastern San Bernardino County |

State of California

California Environmental Protection Agency
AIR RESOURCES BOARD

# Nonattainment Area Designations for the Revised Federal PM2.5 24-Hour Standard

Release Date: December 4, 2007
Public Meeting Date: December 6 - 7, 2007

## CALIFORNIA AIR RESOURCES BOARD

**NOTICE OF PUBLIC MEETING TO HEAR A REPORT ON STAFF'S NONATTAINMENT AREA RECOMMENDATIONS FOR THE REVISED FEDERAL PM2.5 STANDARD**

The Air Resources Board (the Board or ARB) staff will present nonattainment area recommendations for the new federal 35 ug/m$^3$ 24-hour $PM_{2.5}$ standard. ARB will submit these recommendations to the United States Environmental Protection Agency (U.S. EPA) by December 18, 2007.

| | |
|---|---|
| DATE: | December 6 & 7, 2007 |
| TIME: | 9:00 a.m. |
| PLACE: | Air Resources Board<br>Auditorium<br>9530 Telstar Avenue<br>El Monte, California 91731 |

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, and will continue at 8:30 a.m., December 7, 2007. This item is expected to be considered on December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

**BACKGROUND**

The federal Clean Air Act requires U.S. EPA to set health-based National Ambient Air Quality Standards. On December 18, 2006, the U.S. EPA lowered the 24-hour $PM_{2.5}$ standard from 65 ug/m$^3$ to 35 ug/m$^3$. Due to the standard revision, ARB is required to submit nonattainment area recommendations and appropriate boundaries to U.S. EPA for this standard by December 18, 2007. The nonattainment area recommendations are based on 2004-2006 $PM_{2.5}$ air quality monitoring data.

U.S. EPA plans to finalize nonattainment area designations effective April 2009, based on 2005-2007 $PM_{2.5}$ air quality monitoring data. State implementation plans will be due three years after the effective date of designations. Attainment for this new standard will be required by April 2019.

## PROPOSED ACTION

ARB staff will recommend that the South Coast Air Quality Management District, the San Joaquin Valley Air Pollution Control District, the Bay Area Air Quality Management District, the Sacramento Air Quality Management District, the combined cities of Yuba City/Marysville, the city of Chico, and the city of Calexico be designated as nonattainment for the new 35 $ug/m^3$ 24-hour $PM_{2.5}$ standard.

## AVAILABILITY OF DOCUMENTS

ARB staff will prepare a written Staff Report prior to the meeting. Copies of the Staff Report may be obtained from the Board's Public Information Office, 1001 "I" Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990. This notice and Staff Report may also be obtained from ARB's internet site at www.arb.ca.gov/desig/pm25desig/pm25desig.htm.

## SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and in writing or by e-mail before the meeting. To be considered by the Board, written comment submissions not physically submitted at the meeting must be received **no later than 12:00 noon, December 5, 2007,** and addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and any other search engines.

The Board requests, but does not require that 30 copies of any written statement be submitted and that written and e-mail statements be filed at least 10 days prior to the meeting so that ARB staff and Board members have time to fully consider each comment. Further inquiries regarding this matter should be directed to Ms. Sylvia Zulawnick, Manager of the Particulate Matter Analysis Section, Planning and Technical Support Division, 1001 I Street, Sacramento, California 95814 or by e-mail at szulawni@arb.ca.gov, or Jill Glass, Air Pollution Specialist, Planning and Technical Support Division at (916) 322-6161, 1001 I Street, Sacramento, California 95814 or by e-mail at jglass@arb.ca.gov.

CALIFORNIA AIR RESOURCES BOARD

/S/

James N. Goldstene
Executive Officer

Date: November 20, 2007

## Background

On December 18, 2006, the U.S. EPA strengthened the federal 24-hour average air quality standard for particulate matter 2.5 microns or less in diameter (PM2.5) from 65 $ug/m^3$ to 35 $ug/m^3$. The State of California is required to submit nonattainment area recommendations and appropriate boundaries to U.S. EPA for this standard by December 18, 2007. The purpose of this report is to share with the Board the staff's technical analysis and nonattainment recommendations that will be sent to U.S. EPA. U.S. EPA will make final designations in April 2009.

ARB staff has performed an analysis to determine appropriate nonattainment areas throughout the state using criteria outlined in the U.S. EPA's guidance memorandum (*June 8, 2007, Area Designations for the Revised 24-Hour Fine Particle National Ambient Air Quality Standards, Memorandum from Robert J. Meyers, Acting Assistant Administrator, Office of Air and Radiation to Regional Administrators, Regions I-X*). Determination of attainment/nonattainment is based on comparing a three-year average of the $98^{th}$ percentile 24-hour average concentration to the level of the standard. The nonattainment area recommendations contained in this report are based on 2004-2006 PM2.5 air quality monitoring data.

U.S. EPA guidance recommends that in making boundary recommendations for nonattainment areas, states evaluate each area on a case-by-case basis in consideration of the following nine factors:

- Emissions
- Air quality data
- Population density
- Traffic and commuting patterns
- Expected growth
- Meteorology
- Geography/topography
- Jurisdictional boundaries
- Level of emission control

The Clean Air Act requires that a nonattainment area must include not only the area that is violating the standard, but also nearby areas that contribute to the violation. Accordingly, ARB's recommended nonattainment boundaries are sufficiently large to include both the areas that violate the standard and the areas that contribute to the violations.

The guidance further states that air quality monitoring data affected by exceptional events may be excluded from use in identifying a violation if they meet certain criteria. In 2007, wildfires may have impacted PM2.5

concentrations throughout the State. ARB will submit the required documentation to U.S.EPA in accordance with federal policy.

## Air Quality Analysis

ARB maintains a comprehensive PM2.5 monitoring network, including Federal Reference Method (FRM) mass samplers, continuous mass samplers, and chemical speciation samplers. We use FRM monitoring data to determine PM2.5 concentrations in relation to the federal standard, and we use speciation samplers to determine the nature of the PM2.5 pollution. We base our initial recommendations on ambient PM2.5 concentrations measured from 2004 through 2006 by 81 FRM, sited and operated in accordance with federal requirements, located throughout the State. Table 1 provides the 24-hour PM2.5 design value for air districts with monitors violating the standard.

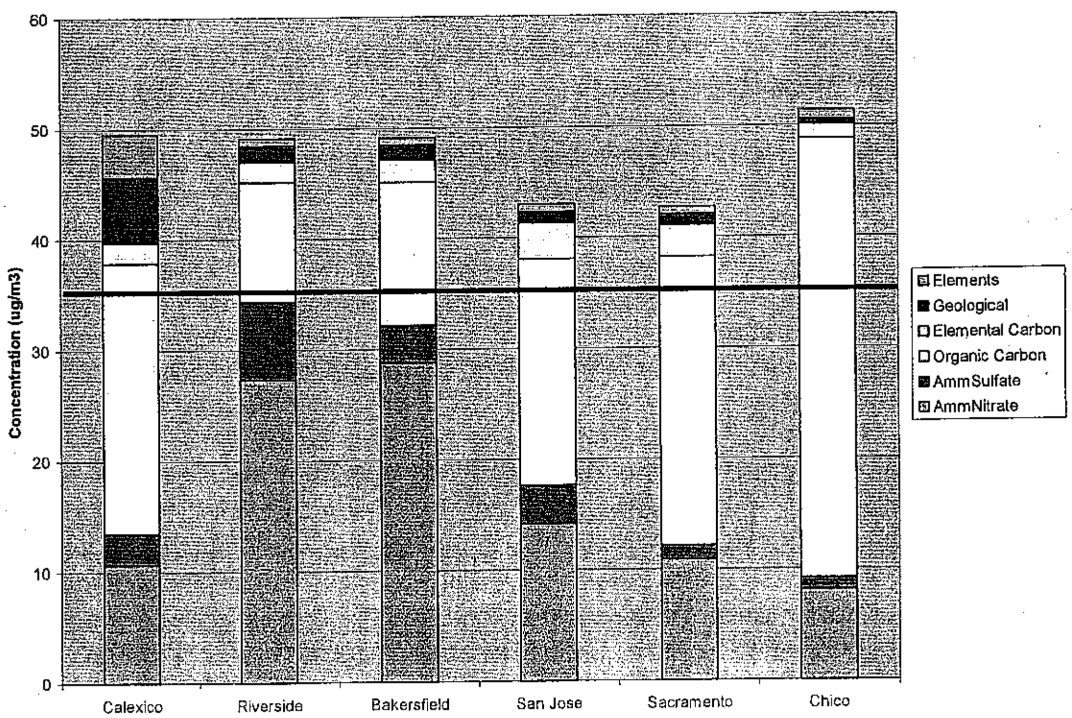
**Table 1: Violating Area Design Values**

| Violating Area | 24-hour Design Value | Air District |
|---|---|---|
| Riverside – Rubidoux, Riverside County | 57 ug/m3 | South Coast Air District |
| Bakersfield, Kern County | 64 ug/m3 | San Joaquin Valley Air District |
| Chico, Butte County | 56 ug/m3 | Butte County Air District |
| Calexico – Ethel St., Imperial County | 40 ug/m3 | Imperial County Air District |
| Sacramento – Del Paso Manor, Sacramento County | 49 ug/m3 | Sacramento Metropolitan Air District |
| San Jose – Jackson, Santa Clara County | 39 ug/m3 | Bay Area Air District |
| Vallejo, Solano County | 36 ug/m3 | Bay Area Air District |
| Yuba City, Sutter County | 40 ug/m3 | Feather River Air District |

Figure 1 displays the average chemical composition on days with PM2.5 concentrations greater than the 35 ug/m3 standard in these areas. As shown, ammonium nitrate and organic carbon are the two greatest contributors to the total PM2.5 concentration. Ammonium nitrate is a secondary pollutant, formed from reactions of NOx and ammonia. Recent studies conducted during the California Regional Particulate Matter Air Quality Study (CRPAQS), have demonstrated that ammonium nitrate is regionally distributed, with similar concentrations in both urban and rural areas (Chow 2005, Turkiewicz 2006). The majority of the emissions that cause high ammonium nitrate are dominated by mobile sources. ARB's statewide mobile source strategy is currently, and will continue to reduce emissions leading to ammonium nitrate formation.

In contrast, organic carbon is a localized pollutant and typically is not transported beyond a small source region. In northern California, concentrations of organic carbon are highest during the winter months, November through February, suggesting that residential wood combustion is a key source, along with other combustion emissions from vehicles, agricultural and prescribed burning, and stationary sources. Conditions during the winter months are cold and stagnant, with light winds (Chow 2006, Turkiewicz 2006). CRPAQS research indicates that organic and elemental carbon is low at rural sites, consistent with a weak source of primary emissions in rural areas (Chow 2006). In addition transport does not play a large role in patterns of wintertime organic carbon. MacDonald 2006 found that "Particulate OM [organic matter] concentrations were high at the urban core sites and low at most rural sites. At distances >50 km from the urban areas, OM concentrations typically declined by a factor of 3-7. Overall, these spatial patterns of OM suggest the impact of urban emissions was largely confined to the urban areas..." Finally, analysis conducted by the Desert Research Institute during CRPAQS on the spatial zone of influence of different source types found that residential wood burning, a large contributor to wintertime carbon concentrations, typically had a zone of influence of only 4 to 5 miles (Chow 2005).

**Figure 1: PM2.5 Chemical Composition at Six Nonattainment Areas**



## Boundary Analysis

In California, the primary considerations for air quality planning are air basin and air district boundaries if the pollution problem is regional in nature. Under State law, air basins are based on a rigorous scientific assessment of geography and meteorology, with consideration of political jurisdictions. Basin boundaries are formally adopted by ARB in regulation. Air districts were established by State statute. ARB typically uses a combination of air basin and air district lines to set boundaries for areas that violate California air quality standards, with exceptions when a single city or community has a unique air pollution problem distinct from the region.

ARB staff recommends retaining the existing nonattainment area boundaries for South Coast and San Joaquin Valley. Ammonium nitrate is the dominant constituent in both the South Coast and the San Joaquin Valley, indicating a region-wide pollution problem. In addition, monitors distributed throughout these two areas record violations of the standard. We recommend the nonattainment areas include the entire air basin for South Coast and San Joaquin Valley to reflect the regional nature of PM2.5 pollution in these areas.

Because organic carbon is primarily an urban scale problem, we are focusing the nonattainment area boundaries for those areas dominated by organic carbon on the urbanized region of each air district. Violations of the PM2.5 standard in San Jose and Vallejo are representative of the broad, urbanized Bay Area. The Bay Area Air Quality Management District is made up of several highly urbanized counties. In addition, speciation data for the Bay Area exhibits a larger contribution from ammonium nitrate and sulfate, reflecting a regional aspect. For these reasons we recommend designating the entire District nonattainment of the PM2.5 standard. Likewise, Sacramento County is predominantly one continuous urbanized area, with multiple monitors violating the standard. While there are urbanized areas on the periphery of Sacramento County, monitors in these areas do not violate the standard. Therefore, ARB staff recommends the Sacramento Metropolitan Air Quality Management District be designated nonattainment of the PM2.5 standard.

In contrast, the Feather River and Butte Air Districts have large rural portions, therefore, we are proposing designating only the primary urbanized area within each district where the population density is sufficient to contribute to localized wood smoke problems. Other small communities in the Sacramento Valley with PM2.5 monitoring show concentrations below the standard, suggesting that the problem is limited to the identified urban areas. ARB staff recommends a focused nonattainment area for the cities of Chico, and Yuba City/Marysville to reflect the localized nature of the PM2.5 problem in these regions.

In the case of Calexico, we believe that the City of Calexico would attain the PM2.5 air quality standard but for emissions emanating from outside of the

United States. Calexico is on the U.S. – Mexico border, at the southern end of Imperial County. Based on the available information, we believe that violations of the PM2.5 standard are localized in Calexico and the much larger adjacent city of Mexicali, Mexico. ARB plans to use the provisions in the Clean Air Act for dealing with plans along international border areas.

## Designation Recommendations

After careful evaluation of nine factors, ARB recommends that the U.S. EPA designate seven areas as nonattainment for the PM2.5 standard:

- South Coast Air Basin
- San Joaquin Valley Air Basin
- Bay Area Air Quality Management District
- Sacramento Metropolitan Air Quality Management District
- The combined cities of Yuba City/Marysville within the Feather River Air Quality Management District
- The City of Chico within the Butte County Air Quality Management District
- The City if Calexico within the Imperial County Air Pollution Control District

## References


MacDonald, C.P. et al, 2006, "Transport and Dispersion During Wintertime Particulate Matter Episodes in the San Joaquin Valley, California", *J. A&WMA*. 56:961-976.

Chow. J.C. et al, 2006, "PM2.5 Chemical Composition and Spatiotemporal Variability During the California Regional PM10/PM2.5 Air Quality Study", *J. Geo. Res.* DOI:10.1029.

Turkiewicz, K. et al, 2006, "Comparison of Two Winter Air Quality Episodes During the California Regional Particulate Air Quality Study", *J. A&WMA*, 56:467-473.

Chow, J.C. et al, 2005, "California Regional PM10/PM2.5 Air Quality Study Initial Data Analysis of Field Program Measurements", prepared for the San Joaquin Valleywide Air Pollution Study Agency.

## Enclosure 3

## State of California
## Information to Support Recommendations for Federal PM2.5 Nonattainment Area Boundaries

### EXISTING NONATTAINMENT AREAS

**South Coast Air Basin**

In 2004, the South Coast Air Basin was designated nonattainment of the 24-hour PM2.5 standard of 65ug/m3. Based on 2004 – 2006 monitoring data, the South Coast Air Basin remains in nonattainment of the revised PM2.5 standard with a design value of 57 ug/m3 measured at the Riverside – Rubidoux monitoring site. Consideration of U.S. EPA's nine factors indicates broad regional contribution to elevated PM2.5 levels and supports the use of the air basin boundary. ARB staff recommends that the boundaries remain consistent with the previous PM2.5 nonattainment boundary.

The recommended South Coast Air Basin PM2.5 nonattainment area includes Western Los Angeles (excluding Catalina and San Clemente Islands), Orange, Southwestern San Bernardino, and Western Riverside Counties. This area is under the jurisdiction of the South Coast Air Quality Management District.

**San Joaquin Valley Air Basin**

In 2004, the San Joaquin Valley Air Basin was designated nonattainment of the 24-hour PM2.5 standard of 65ug/m3. Based on 2004 – 2006 monitoring data, the San Joaquin Valley Air Basin remains in nonattainment of the revised PM2.5 standard with a design value of 64 ug/m3 measured at the Bakersfield – Golden monitoring site. Consideration of U.S. EPA's nine factors indicates broad regional contribution to elevated PM2.5 levels and supports the use of the air basin boundary. ARB staff recommends that the boundaries remain consistent with previous PM2.5 nonattainment boundary.

The recommended San Joaquin Valley PM2.5 nonattainment area consists of San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulare and Western Kern Counties. The area is under the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District.

## NEW NONATTAINMENT AREAS

### Sacramento Metropolitan Air Quality Management District

**Jurisdictional boundary**
The presumptive boundary for the PM2.5 nonattainment area includes all of Sacramento County under the jurisdiction of the Sacramento Metropolitan Air Pollution Control District.

ARB staff believes that a district level nonattainment area boundary is appropriate due to the localized nature of the PM2.5 problem. The two key components of PM 2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

**Air Quality**
Our initial recommendation for the Sacramento Metropolitan Air Quality Management District is based on ambient PM2.5 concentrations measured from 2004 through 2006. Three monitoring sites throughout Sacramento County monitor for PM2.5, however only two sites – Del Paso Manor and Stockton Boulevard – have complete data to support designations. Our nonattainment recommendation is based on a design value of 49 ug/m3 measured at the Del Paso Manor monitoring site. The Stockton Boulevard monitor is also exceeding the federal standard with a design value of 39 ug/m3.

Areas surrounding Sacramento County include the counties of Yolo, Solano, Placer, El Dorado, Sutter, Yuba, and San Joaquin. Exceedance of the PM2.5 standard in Yuba, Sutter, and San Joaquin County will be included in the recommended nonattainment area for Marysville/Yuba City, and San Joaquin Valley APCD, respectively. Solano County is divided between two air districts, the Bay Area AQMD and Yolo-Solano AQMD. The design value for Solano County is 36 ug/m3 measured at the Vallejo monitoring site, which is under the jurisdiction of the Bay Area AQMD and will therefore be included in the recommended Bay Area nonattainment area. Yolo County is in attainment of the standard with a design value of 30 ug/m3 measured at the Woodland monitoring site. Placer County is in attainment with a design value of 31 ug/m3 measured at the Roseville monitoring site.

The chemical makeup of PM2.5 in Sacramento is dominated by organic carbon and ammonium nitrate. Figure 2 and Figure 3 illustrate the seasonal pattern and chemical composition of PM2.5 at the Del Paso Manor and T Street sites with highest concentrations occurring in the winter time. Organic carbon is the largest component of PM2.5 and increases considerably during the winter months. As shown in Figure 4, organic carbon accounts for roughly 50 percent of the 2004 –

2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 22 – 27 percent of the average composition on exceedance days. During the fall and winter, the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

**Figure 2: Seasonal Pattern of PM2.5 Chemical Components**

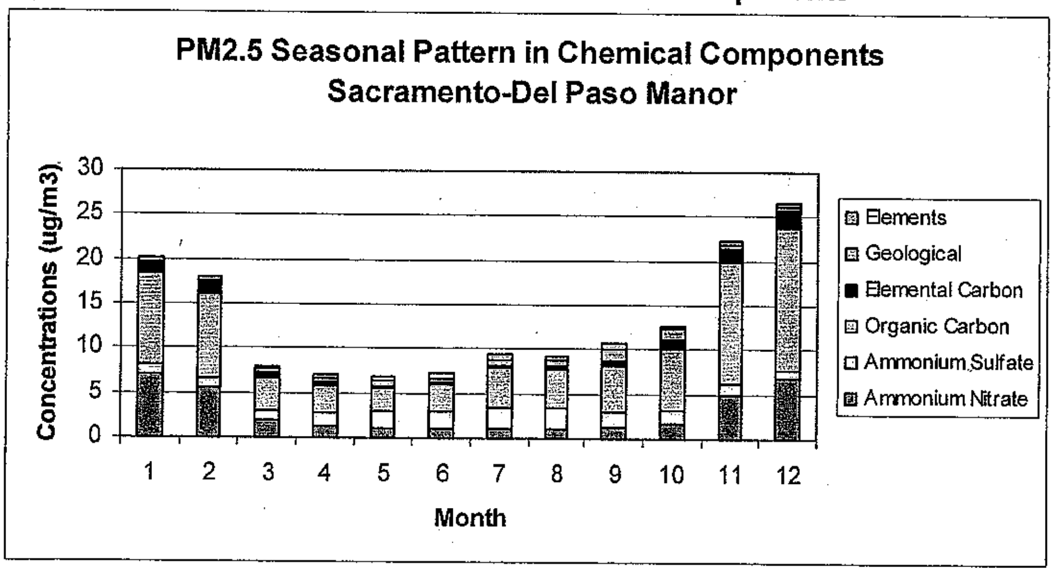


**Figure 3: Seasonal Pattern of PM2.5 Chemical Components**

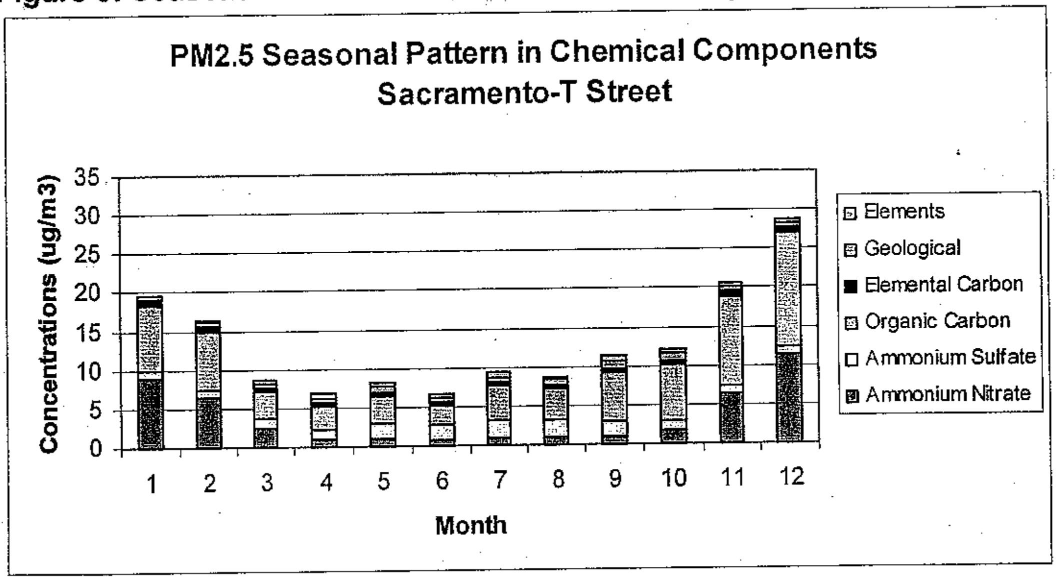
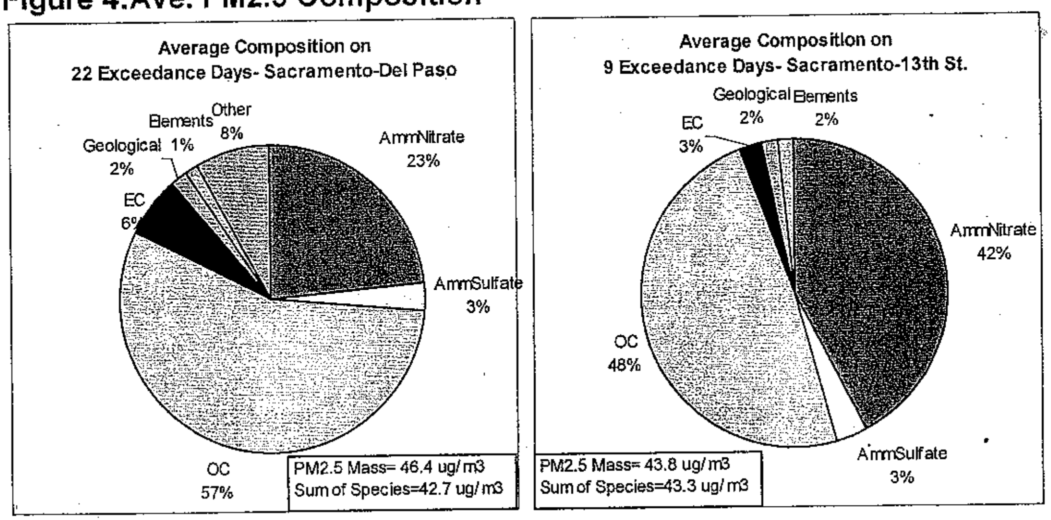



**Figure 4:Ave. PM2.5 Composition**




## Geography/Topography/Meteorology

Sacramento County encompasses approximately 994 square miles in the heart of California's Central Valley. Sacramento County is bounded by the Sierra Nevada foothills to the northeast and the Sacramento-San Joaquin River Delta to the southwest. The lower Sacramento Valley extends through the western and central portions of the county. Elevations range from sea level in the southwest to approximately 400 feet about sea level in the eastern areas of the county.

High PM2.5 concentrations in the Sacramento area appear to be dependant upon calm-to-light winds and not as dependent upon wind direction. This suggests that there is enough activity within the Sacramento area to generate high PM2.5 concentrations under many conditions, and that high concentrations are not being caused by adjacent areas such as Placer, Sutter or Yolo Counties.

**Emissions**

The presumptive boundary for the PM2.5 nonattainment area includes all of Sacramento County under the jurisdiction of the Sacramento Metropolitan Air Pollution Control District. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to Sacramento include Yolo, Solano, Sutter, Placer, El Dorado, Amador, San Joaquin, and a small portion of Contra Costa. The nature of the PM2.5 problem in Sacramento County is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Sacramento County. Emissions generated in Sutter County and San Joaquin County are included in the recommended Marysville/Yuba City and San Joaquin Valley Air District nonattainment areas, respectively. Table 1 provides emissions in tons per day of a primary pollutant contributing to PM2.5 from stationary, area and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

**Table 1: NOx Winter Emissions Sacramento and Surrounding Counties**

| **Sacramento County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 3.9 | 3.9 | 4.3 |
| Area Sources | 4.0 | 4.0 | 4.1 |
| Mobile Sources | 75.1 | 62.5 | 34.5 |
| **Yolo County** | | | |
| Stationary Sources | 3.0 | 2.9 | 2.8 |
| Area Sources | 0.7 | 0.7 | 0.7 |
| Mobile Sources | 21.3 | 17.3 | 9.9 |
| **Solano County** | | | |
| Stationary Sources | 6.3 | 6.5 | 7.1 |
| Area Sources | 1.6 | 1.7 | 1.7 |
| Mobile Sources | 42.4 | 36.0 | 21.8 |
| **Placer County** | | | |
| Stationary Sources | 4.5 | 4.7 | 5.1 |
| Area Sources | 1.6 | 1.6 | 1.6 |
| Mobile Sources | 28.2 | 23.4 | 13.7 |
| **El Dorado County** | | | |
| Stationary Sources | 0.4 | 0.4 | 0.4 |
| Area Sources | 1.3 | 1.3 | 1.4 |
| Mobile Sources | 8.8 | 7.4 | 4.3 |
| **Sutter County** | | | |
| Stationary Sources | 3.6 | 3.9 | 3.9 |
| Area Sources | 0.9 | 0.8 | 0.8 |
| Mobile Sources | 14.3 | 12.9 | 6.9 |

Table 1 (cont.)

| **Amador County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 2.0 | 2.1 | 2.3 |
| Area Sources | 0.3 | 0.3 | 0.3 |
| Mobile Sources | 3.2 | 2.7 | 1.7 |
| **San Joaquin County** | | | |
| Stationary Sources | 14.8 | 15.2 | 17.3 |
| Area Sources | 2.7 | 2.6 | 2.5 |
| Mobile Sources | 88.8 | 72.9 | 40.3 |

**Population Density and Degree of Urbanization**
According to the U.S Census Bureau, the population of Sacramento County in 2006 is estimated to be 1,374,724 based on 2000 census data. This represents an 11 percent increase in population since 2000, and a 25 percent increase since 1990.

**Table 2: Sacramento County Population**

| | **1990** | **2000** | **2006** |
|---|---|---|---|
| Population | 1,041,219 | 1,223,499 | 1,374,724 |
| Population Density | 1078 persons/sq mile | 1267 persons/sq mile | 1423 persons/sq mile |

**Traffic and Commuting Patterns**
The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. In Sacramento County, traffic is expected to increase by 7 percent by 2010 and by 11 percent by 2020. Vehicle miles traveled is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources are expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

**Table 3: Sacramento County Daily Vehicle Miles Traveled**

| | **1990** | **1995** | **2000** | **2005** | **2010** | **2015** | **2020** |
|---|---|---|---|---|---|---|---|
| Ave. Daily VMT/1000 | 24774 | 27057 | 27090 | 30519 | 33091 | 35567 | 37370 |

**Expected Growth**
Sacramento County is expected to grow by 10 percent from 2005 to 2010, and by 28 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in Sacramento County. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

**Table 4: Sacramento County Projected Growth**

| | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|
| Population | 1,233,560 | 1,392,930 | 1,555,848 | 1,751,264 | 1,946,679 |

**Level of Control of Emissions Sources**

Sacramento County has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Metropolitan Air District administers a smoke management program for open burning, consistent with ARB's statewide regulation. In addition, the district recently adopted a comprehensive control strategy to reduce emissions from residential wood burning, a key source of localized particulate matter emissions. Areas surrounding Sacramento County have similar level of control regarding smoke management and control of NOx sources.

## Bay Area Air Quality Management District

**Jurisdictional Boundary**

The presumptive boundary for the PM2.5 nonattainment area includes the counties of Sonoma, Napa, Solano, Marin, Contra Costa, San Francisco, Alameda, San Mateo, and Santa Clara under the jurisdiction of the Bay Area Air Quality Management District (AQMD). The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

**Air Quality**

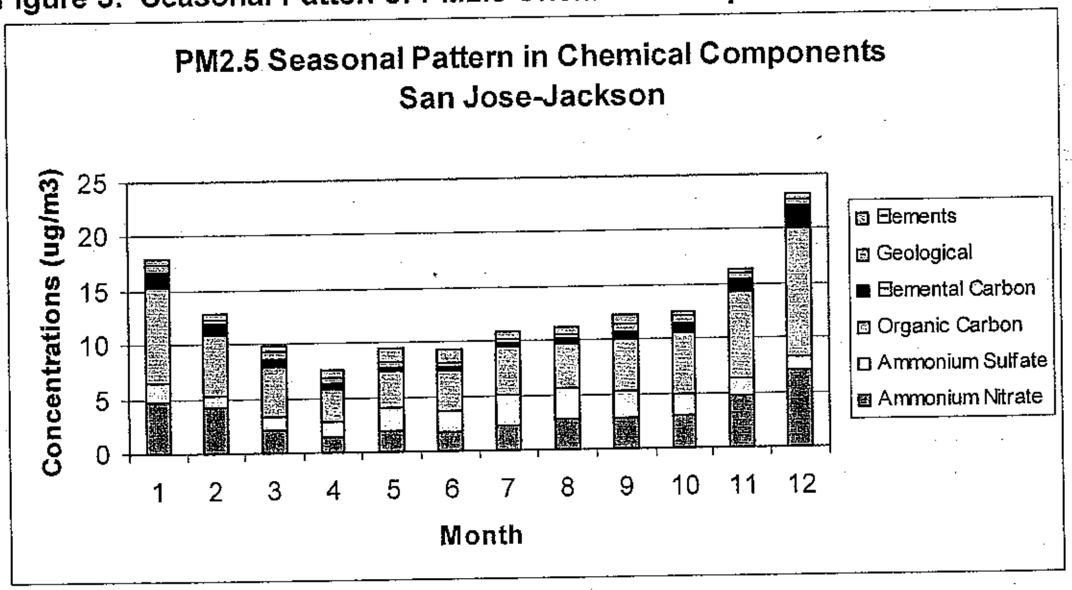
Our initial recommendation for the Bay Area AQMD is based on ambient PM2.5 concentrations measured from 2004 through 2006. Our nonattainment recommendation is based on a design value of 39 ug/m3 measured at the San Jose – Jackson Street monitoring site in Santa Clara county, and a design value of 36 ug/m3 measured at the Vallejo monitoring site in Solano county.

Areas surrounding the Bay Area AQMD include the counties of Mendocino, Lake, Yolo, Sacramento, San Joaquin, Stanislaus, Merced, San Benito, and Monterey. Exceedances of the PM2.5 standard in Sacramento will be included in the recommended Sacramento Metropolitan AQMD nonattainment area. Exceedances of the standard in San Joaquin, Stanislaus, and Merced counties will be included in the recommended San Joaquin Valley APCD nonattainment area. Mendocino, Lake, Yolo, San Benito, and Monterey counties are all in attainment of the standard.

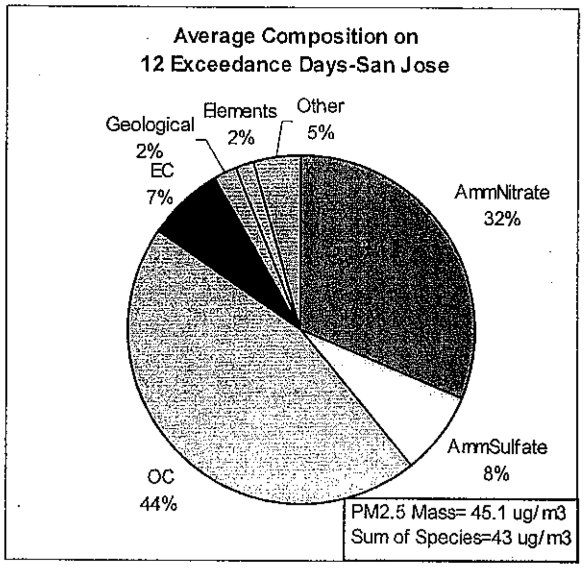
The chemical makeup of PM2.5 in the Bay Area is dominated by organic carbon and ammonium nitrate. Figure 5 illustrates the seasonal pattern and chemical composition of PM2.5 at the San Jose monitoring site, with highest concentrations occurring in the winter time. As shown in Figure 6, organic carbon accounts for roughly 44 percent of the 2004 – 2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning, and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 32 percent of the average composition on exceedance days. During the fall and winter, the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer.

**Figure 5: Seasonal Patten of PM2.5 Chemical Components**



## Figure 6: Ave PM2.5 Composition




## Geography/ Topography/Meteorology

The San Francisco Air Basin encompasses approximately 5,430 square miles and consists of all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, and Santa Clara counties, the southern half of Sonoma County and the southwestern portion of Solano County. The region is characterized by complex terrain, consisting of coastal mountain ranges, rugged hillsides, and inland valleys and bays. Elevations can range from sea level to 1500 feet. The coastal zones tend to be more windy and cooler in the summer that the hotter, drier interior regions with a reversal in the winter months. Precipitation is more typical of a Mediterranean climate with dry summers and wet winters.

The summer climate is dominated by a high pressure center over the Pacific Ocean. Storms rarely affect the coast during the summer, thus the conditions that persist during the summer are a northwest air flow and negligible precipitation. A thermal low pressure area from the Sonoran – Mojave Desert also causes air to flow onshore over the San Francisco Bay Area much of the summer. Air flow over cool Pacific Ocean temperatures produces condensation – a high incidence of fog and stratus clouds are common along the coast in summer.

In winter, the Pacific High weakens and shifts southward, winter storms become frequent. Almost all of the Bay Area's annual precipitation takes place in the November through April period. During the winter rainy periods, inversions are weak or nonexistent, winds are often moderate and air pollution potential is very low. During winter periods when the Pacific High becomes dominant, inversions become strong, winds are light and pollution potential is high. These periods are characterized by winds that flow out of the Central Valley into the Bay Area and often include tule fog.

**Emissions**
The presumptive boundary for the PM2.5 nonattainment area includes the counties of Sonoma, Napa, Solano, Marin, Contra Costa, San Francisco, Alameda, San Mateo, and Santa Clara under the jurisdiction of the Bay Area AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to the Bay Area AQMD include Mendocino, Lake, Yolo, San Joaquin, Stanislaus, Merced, San Benito, and Monterey. The nature of the PM2.5 problem in the Bay Area is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for the Bay Area. Emissions generated in San Joaquin, Stanislaus, and Merced counties are included in the recommended San Joaquin Valley APCD nonattainment area. Table 5 provides emissions in tons per day of a primary pollutant contributing to PM2.5 from stationary, area, and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

**Table 5: NOx Winter Emissions Bay Area and Surrounding Counties**

| **Solano County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 6.3 | 6.5 | 7.1 |
| Area Sources | 1.6 | 1.7 | 1.7 |
| Mobile Sources | 42.4 | 36.0 | 21.8 |
| **Santa Clara County** | | | |
| Stationary Sources | 11.8 | 12.2 | 13.2 |
| Area Sources | 6.9 | 7.1 | 7.5 |
| Mobile Sources | 87.8 | 71.5 | 41.0 |
| **Sonoma County** | | | |
| Stationary Sources | 0.8 | 0.8 | 0.8 |
| Area Sources | 1.9 | 1.9 | 2.0 |
| Mobile Sources | 23.4 | 18.7 | 9.8 |
| **Napa County** | | | |
| Stationary Sources | 0.5 | 0.6 | 0.6 |
| Area Sources | 0.6 | 0.6 | 0.7 |
| Mobile Sources | 10.5 | 8.4 | 4.5 |
| **Marin County** | | | |
| Stationary Sources | 0.4 | 0.4 | 0.4 |
| Area Sources | 1.6 | 1.6 | 1.7 |
| Mobile Sources | 16.4 | 14.6 | 12.5 |

Table 5 (cont.)

| **Contra Costa County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 24.3 | 25.2 | 28.0 |
| Area Sources | 4.5 | 4.6 | 4.8 |
| Mobile Sources | 62.2 | 50.9 | 30.4 |
| **San Francisco County** | | | |
| Stationary Sources | 1.6 | 1.6 | 1.6 |
| Area Sources | 3.5 | 3.6 | 3.8 |
| Mobile Sources | 46.6 | 42.3 | 37.0 |
| **Alameda County** | | | |
| Stationary Sources | 5.9 | 6.1 | 6.7 |
| Area Sources | 5.9 | 6.1 | 6.4 |
| Mobile Sources | 128.5 | 106.3 | 67.1 |
| **San Mateo County** | | | |
| Stationary Sources | 1.7 | 1.7 | 1.8 |
| Area Sources | 3.4 | 3.5 | 3.7 |
| Mobile Sources | 46.6 | 42.3 | 37.0 |
| **San Joaquin County** | | | |
| Stationary Sources | 14.8 | 15.2 | 17.3 |
| Area Sources | 2.7 | 2.6 | 2.5 |
| Mobile Sources | 88.8 | 72.9 | 40.3 |
| **Stanislaus County** | | | |
| Stationary Sources | 9.3 | 9.4 | 10.2 |
| Area Sources | 2.7 | 2.6 | 2.5 |
| Mobile Sources | 47.7 | 38.0 | 19.4 |
| **Merced County** | | | |
| Stationary Sources | 6.0 | 5.9 | 5.8 |
| Area Sources | 1.6 | 1.6 | 1.5 |
| Mobile Sources | 53.7 | 41.5 | 20.5 |
| **Mendocino County** | | | |
| Stationary Sources | 0.9 | 0.9 | 1.0 |
| Area Sources | 0.8 | 0.9 | 0.9 |
| Mobile Sources | 24.1 | 23.1 | 24.2 |
| **Lake County** | | | |
| Stationary Sources | 0.3 | 0.4 | 0.4 |
| Area Sources | 0.6 | 0.6 | 0.6 |
| Mobile Sources | 5.7 | 5.0 | 3.1 |
| **San Benito County** | | | |
| Stationary Sources | 0.7 | 0.7 | 0.7 |
| Area Sources | 0.2 | 0.2 | 0.2 |
| Mobile Sources | 12.9 | 9.8 | 4.2 |

Table 5 (cont.)

| **Monterey County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 11.6 | 12.0 | 13.0 |
| Area Sources | 1.5 | 1.4 | 1.4 |
| Mobile Sources | 48.9 | 44.4 | 41.1 |
| **Yolo County** | | | |
| Stationary Sources | 3.0 | 2.9 | 2.8 |
| Area Sources | 0.7 | 0.7 | 0.7 |
| Mobile Sources | 21.3 | 17.3 | 9.9 |

**Population Density and Degree of Urbanization**
The Bay Area Air Basin has an estimated population of 6,953,438 as of 2005, based on data derived from reports developed by the California Department of Finance, Demographic Research Unit. This represents approximately a 4 percent increase in population since 2000, and a 15 percent increase since 1990.

**Table 6: San Francisco Bay Area Air Basin Population**

| | **1990** | **2000** | **2005** |
|---|---|---|---|
| Population | 5,874,353 | 6,646,727 | 6,953,438 |
| Population Density | 1100 persons/sq mile | 1245 persons/sq mile | 1302 persons/sq mile |

**Traffic and Commuting Patterns**
The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. In the Bay Area Air Basin traffic is expected to increase by 11 percent by 2010 and by 20 percent by 2020. Vehicle miles traveled is projected to increase faster than the population, yet NOx emissions from mobile sources are expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

**Table 7: Bay Area Air Basin Vehicle Miles Traveled**

| | **1990** | **1995** | **2000** | **2005** | **2010** | **2015** | **2020** |
|---|---|---|---|---|---|---|---|
| Ave. Daily VMT/1000 | 133,990 | 144,854 | 159,271 | 172,581 | 193,300 | 202,212 | 213,900 |

**Expected Growth**
The Bay Area AQMD is expected to grow by 5 percent from 2005 to 2010 and by 15 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in the Bay Area. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

Table 8: Bay Area Air Basin Projected Growth

| | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|
| Population | 6,646,727 | 6,953,438 | 7,337,485 | 7,736,635 | 8,135,781 |

**Level of Control of Emissions Sources**

The Bay Area has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Bay Area AQMD administers a smoke management program for open burning. Areas surrounding the Bay Area AQMD have similar levels of control regarding smoke management and control of NOx sources.

## The Combined Cities of Marysville and Yuba City within the Feather River Air Quality Management District

**Jurisdictional Boundary**

The presumptive boundary for the PM2.5 nonattainment area includes the cities of Marysville and Yuba City under the jurisdiction of the Feather River Air Quality Management District (AQMD).

ARB staff believes that a city level PM2.5 nonattainment area boundary is appropriate due to the localized nature of the PM2.5 problem. The cities of Marysville and Yuba City together form one urban area separated only by the county line along the Feather River. The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

**Air Quality**

Our initial recommendation for Marysville/Yuba City is based on ambient PM2.5 concentrations measured from 2004 through 2006. The Feather River AQMD has only one monitor to measure PM2.5, located in Yuba City in Sutter County. Our nonattainment recommendation is based on a design value of 40 ug/m3 measured at the Yuba City monitoring site. Due to the close proximity of the city of Marysville in Yuba County, we recommend the Marysville/Yuba City urbanized region be included in the nonattainment area.

Areas surrounding Feather River AQMD include the counties of Butte, Glenn, Colusa, Yolo, Sacramento, Placer, Nevada, and Sierra. Exceedance of the PM2.5 standard in Sacramento County will be included in the recommended nonattainment area for the Sacramento Metropolitan AQMD. Exceedance of the standard in Butte County will be included in the recommended nonattainment area for the City of Chico. Yolo County is in attainment of the standard with a design value of 30 ug/m3 measured at the Woodland monitoring site. Placer County is in attainment with a design value of 31 ug/m3 measured at the Roseville monitoring site. Likewise, Glenn, Colusa, Nevada and Sierra counties all are in attainment of the standard.

Speciation data for the Yuba City monitor is not available; however, we believe the speciation data from Sacramento and Chico to be representative of the chemical makeup of PM2.5 in the Maryville/Yuba City urbanized area. The chemical composition of PM2.5 in Sacramento is dominated by organic carbon and ammonium nitrate. Figure 7 and Figure 8 illustrate the seasonal pattern and chemical composition of PM2.5 at the Del Paso Manor site in Sacramento County, and the Chico site in Butte County, with the highest concentrations occurring in the winter time. As shown in Figure 9, organic carbon accounts for roughly 57 percent and 75 percent of the average PM2.5 composition on exceedance days at the Del Paso Manor and Chico monitoring sites, respectively. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 16 to 23 percent of the 2004 – 2006 average at Sacramento and Chico. During the fall and winter the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

Figure 7: Seasonal Pattern of PM2.5 Chemical Components

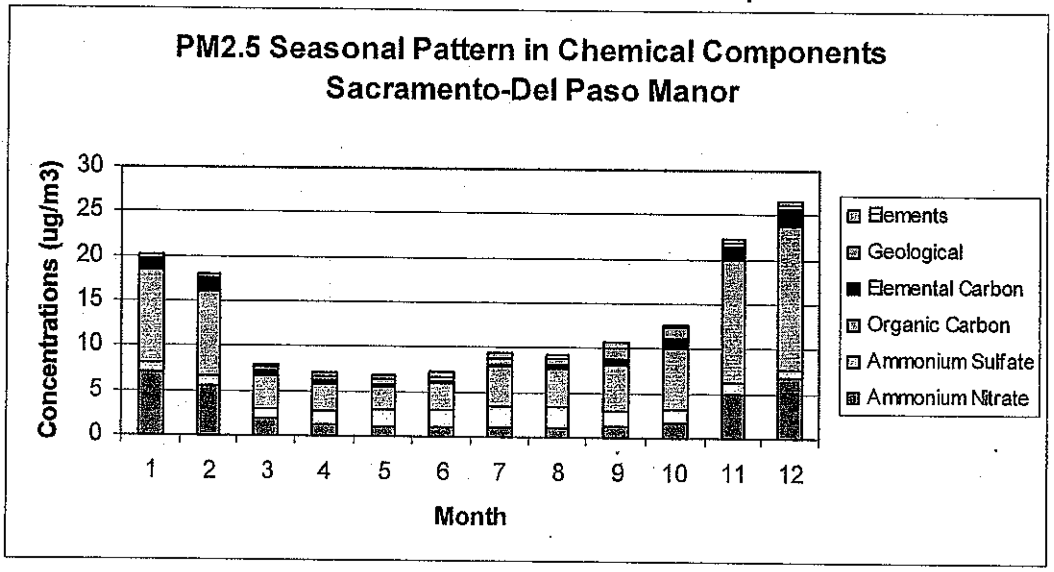



Figure 8: Seasonal Pattern of PM2.5 Chemical Components

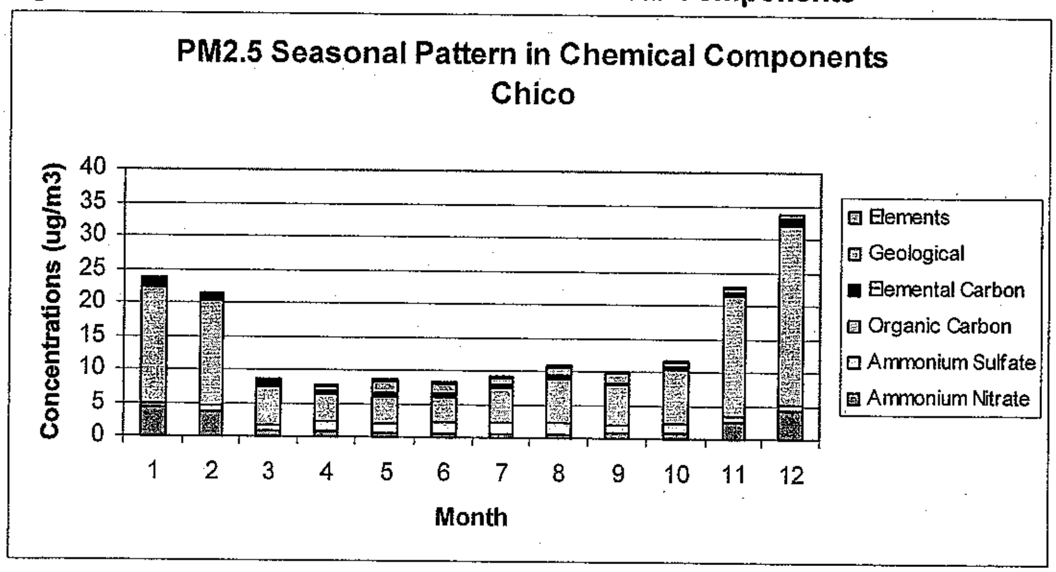
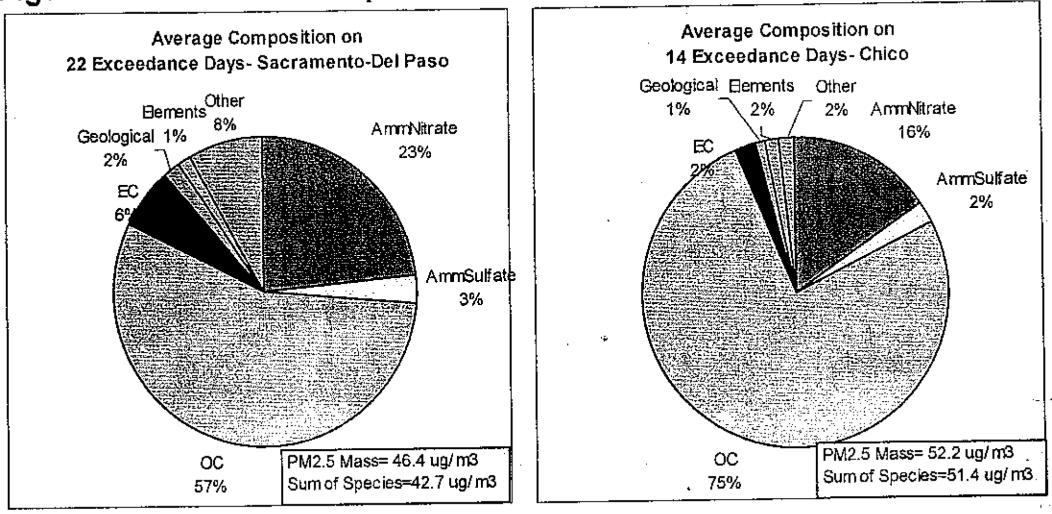


**Figure 9: Ave. PM2.5 Composition**




## Geography/Topography/Meteorology

The city of Marysville is in Yuba County, while Yuba City is in Sutter County. Marysville and Yuba City are considered one metropolitan area, separated only by the Feather River. Yuba and Sutter counties form the Feather River AQMD. Together, the two counties encompass 1,234 square miles. The Feather River AQMD is part of the larger Northern Sacramento Valley Air Basin (NSVAB), and includes the counties of Butte, Colusa, Glenn, Shasta, and Tehama. The NSVAB is bounded on the north and west by the Coastal Mountain Range and on the east by the southern portion of the Cascade Mountain Range and the northern portion of the Sierra Nevada Mountains. These mountain ranges reach heights in excess of 6000 feet with peaks rising much higher. This provides a substantial physical barrier to locally created pollution. Although a significant area of the NSVAB is above 1000 feet sea level, the majority of the Feather River AQMD is located in the Valley floor and foothill regions. The valley is often subjected to inversion layers that, coupled with geographic barriers and high summer temperatures, create a high potential for air pollution problems.

## Emissions

The presumptive boundary for the PM2.5 nonattainment area includes the cities of Marysville and Yuba City under the jurisdiction of the Feather River AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to Feather River AQMD include Butte, Glenn, Colusa, Yolo, Sacramento, Placer, Nevada, and Sierra. The nature of the PM2.5 problem in Marysville/Yuba City is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Feather River AQMD. Table 9 provides NOx emissions in tons per day from stationary, area, and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

**Table 9: NOx Winter Emissions Feather River AQMD and Surrounding Counties**

| **Yuba County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 0.7 | 0.7 | 0.7 |
| Area Sources | 0.5 | 0.5 | 0.5 |
| Mobile Sources | 6.2 | 6.6 | 4.9 |
| **Sutter County** | | | |
| Stationary Sources | 3.6 | 3.9 | 3.9 |
| Area Sources | 0.9 | 0.8 | 0.8 |
| Mobile Sources | 14.3 | 12.9 | 6.9 |
| **Sacramento County** | | | |
| Stationary Sources | 3.9 | 3.9 | 4.3 |
| Area Sources | 4.0 | 4.0 | 4.1 |
| Mobile Sources | 75.1 | 62.5 | 34.5 |
| **Yolo County** | | | |
| Stationary Sources | 3.0 | 2.9 | 2.8 |
| Area Sources | 0.7 | 0.7 | 0.7 |
| Mobile Sources | 21.3 | 17.3 | 9.9 |
| **Butte County** | | | |
| Stationary Sources | 1.4 | 1.4 | 1.4 |
| Area Sources | 1.7 | 1.7 | 1.6 |
| Mobile Sources | 23.3 | 19.9 | 11.3 |
| **Glenn County** | | | |
| Stationary Sources | 3.5 | 3.6 | 3.6 |
| Area Sources | 0.1 | 0.1 | 0.1 |
| Mobile Sources | 7.6 | 6.2 | 3.7 |
| **Colusa County** | | | |
| Stationary Sources | 5.1 | 5.1 | 5.0 |
| Area Sources | 0.9 | 0.9 | 0.9 |
| Mobile Sources | 8.4 | 6.7 | 4.0 |
| **Placer County** | | | |
| Stationary Sources | 4.5 | 4.7 | 5.1 |
| Area Sources | 1.6 | 1.6 | 1.6 |
| Mobile Sources | 28.2 | 23.4 | 13.7 |
| **Nevada County** | | | |
| Stationary Sources | 0.2 | 0.2 | 0.3 |
| Area Sources | 1.6 | 1.6 | 1.6 |
| Mobile Sources | 12.8 | 10.1 | 5.5 |
| **Sierra County** | | | |
| Stationary Sources | 0.5 | 0.5 | 0.5 |
| Area Sources | 0.1 | 0.5 | 0.5 |
| Mobile Sources | 0.6 | 0.6 | 0.5 |

### Population Density and Degree of Urbanization

According to the US Census Bureau, the population of Yuba County in 2006 is estimated to be 70,396 based on 2000 census data. This represents a 15 percent increase in population since 2000, and a 17 percent increase since 1990. The 2006 population of Sutter County is estimated to be 91,410 based on 2000 census data. This represents a 14 percent increase in population since 2000, and a 30 percent increase since 1990.

**Table 10: Yuba County and Sutter County Population**

| | 1990 | 2000 | 2006 |
|---|---|---|---|
| **Yuba County** | | | |
| Population | 58,228 | 60,219 | 70,396 |
| Population Density | 92 persons/sq mile | 96 persons/sq mile | 112 persons/sq mile |
| **Sutter County** | | | |
| Population | 64,415 | 78,930 | 91,410 |
| Population Density | 107 persons/sq mile | 131 persons/sq mile | 152 persons/sq mile |

### Traffic and Commuting Patterns

The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. Traffic is expected to increase by 18 percent from 2005 to 2010, and by 39 percent by 2020 in Yuba County. Sutter County is expected to experience a 20 percent increase in traffic from 2005 to 2010, and a 44 percent increase by 2020. Vehicle miles traveled in Feather River AQMD is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources is expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM 2.5 levels.

**Table 11: Yuba County and Sutter County Vehicle Miles Traveled**

| | 1990 | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|---|
| **Yuba County** | | | | | | |
| Ave. Daily VMT/1000 | 1137 | 1278 | 1510 | 1842 | 2157 | 2485 |
| **Sutter County** | | | | | | |
| Ave. Daily VMT/1000 | 1616 | 1921 | 2333 | 2922 | 3534 | 4196 |

### Expected Growth

Feather River is expected to grow by 6 percent from 2005 to 2010, and by 21 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in Feather River AQMD. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

**Table 12: Yuba County and Sutter County Projected Growth**

| | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|
| **Yuba County** | | | | | |
| Population | 60,411 | 67,102 | 71,506 | 78,161 | 84,816 |
| **Sutter County** | | | | | |
| Population | 79,526 | 88,905 | 95,757 | 103,807 | 111,856 |

**Level of Control of Emissions Sources**
Yuba and Sutter Counties have motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California Standards; therefore new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Valley Basinwide Air Pollution Control Council, which includes the Feather River AQMD, administers a smoke management program for open burning, consistent with the ARB's statewide regulation. Areas surrounding Yuba and Sutter Counties have similar level of control regarding smoke management and control of NOx sources.

## City of Chico within the Butte County Air Quality Management District

**Jurisdictional Boundary**
The presumptive boundary for the PM2.5 nonattainment area includes the city of Chico under the jurisdiction of the Butte County Air Quality Management District (AQMD). Chico is located within the Sacramento Valley Air Basin.

ARB staff believes that the Chico city level nonattainment boundary is appropriate due to the localized nature of the PM2.5 problem. The city of Chico is the largest urbanized area in Butte County and is located on the Sacramento Valley floor. Several small communities throughout the Sacramento Valley meet the standard, so ARB staff does not believe it is a broad regional problem. Due to the localized nature of the PM2.5 problem in the urbanized area, we believe the violating area to be restricted to this small geographic region and not extending into the rural and mountainous regions of Butte County. The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

**Air Quality**

Our initial recommendation for the city of Chico is based on ambient PM2.5 concentrations measured from 2004 through 2006. Our nonattainment recommendation is based on a design value of 56 ug/m3 measured at the Chico monitoring site. Butte County has two monitors measuring PM2.5, located in Chico and Gridley, however, only Chico can be used for federal purposes.

Areas surrounding the city of Chico include the counties of Plumas, Tehama, Glenn, Colusa, Sutter and Yuba. Exceedance of the PM2.5 standard in Sutter and Yuba counties will be included in the recommended nonattainment area for the cities of Marysville/Yuba City. Glenn, Colusa, Tehama, and Plumas counties all are in attainment of the standard.

The chemical makeup of PM2.5 in the city of Chico is dominated by organic carbon and ammonium nitrate. Figure 10 illustrates the seasonal pattern and chemical composition of PM2.5 at the Chico monitoring site with highest concentrations occurring in the winter time. As shown if Figure 11, organic carbon accounts for roughly 75 percent of the PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 16 percent on exceedance days. During the fall and winter the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

**Figure 10: PM2.5 Chemical Composition in Chico**

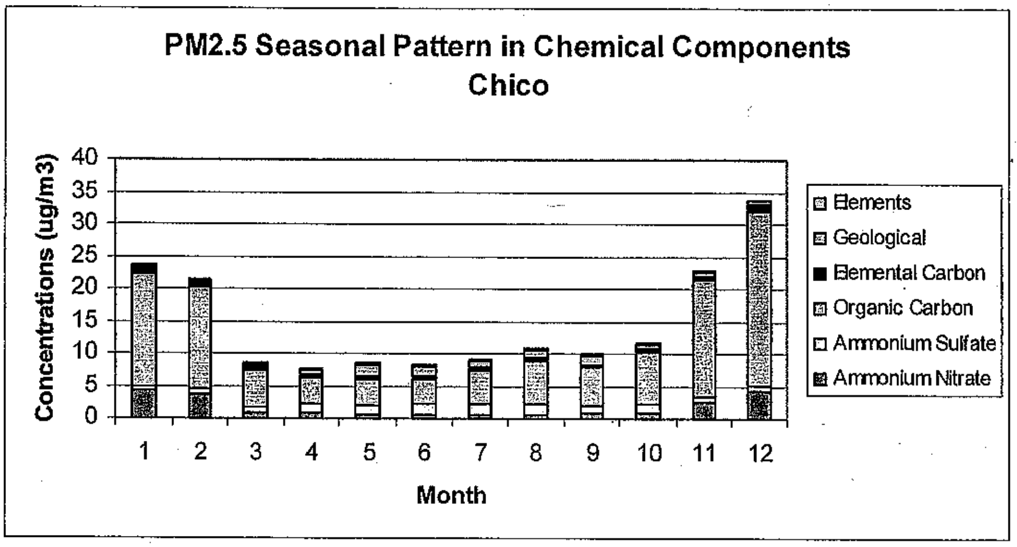
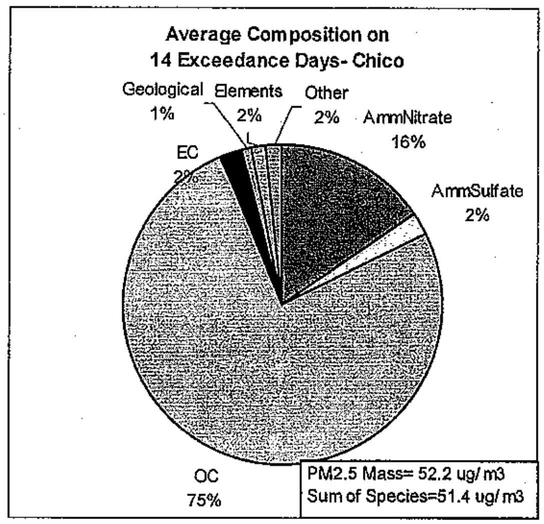



**Figure 11: Average Chemical Composition**




## Geography/Topography/Meteorology

The city of Chico is located at the northeast edge of the Sacramento Valley. The Sierra Nevada Mountains lie to the east, and the Sacramento River lies to the west. Chico sits primarily on the valley floor and is on the whole very flat, but several miles of the eastern city limits venture into the increasingly hilly terrain of the Sierra Nevada foothills. The city limits encompass an area of 30 square miles. Butte County encompasses an area of 1,639 square miles.

Chico is part of the larger Northern Sacramento Valley Air Basin (NSVAB), which includes the counties of Butte, Colusa, Glenn, Shasta, and Tehama. The NSVAB is bounded on the north and west by the Coastal Mountain Range and on the east by the southern portion of the Cascade Mountain Range and the northern portion of the Sierra Nevada Mountains. These mountain ranges reach heights in excess of 6000 feet with peaks rising much higher. This provides a substantial physical barrier to locally created pollution. The valley is often subjected to inversion layers that, coupled with geographic barriers and high summer temperatures, create a high potential for air pollution problems.

**Emissions**

The presumptive boundary for the PM2.5 nonattainment area includes the city of Chico under the jurisdiction of the Butte County AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties include Plumas, Tehama, Glenn, Colusa, Sutter and Yuba. The nature of the PM2.5 problem in Chico is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Butte County. Emissions generated in Sutter and Yuba Counties are included in the recommended Marysville/Yuba City nonattainment area. Table 13 provides emissions in tons per day of the primary pollutant contributing to PM2.5 from stationary, area and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

**Table 13: NOx Winter Emissions Butte County AQMD and Surrounding Counties**

| **Butte County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 1.4 | 1.4 | 1.4 |
| Area Sources | 1.7 | 1.7 | 1.6 |
| Mobile Sources | 23.3 | 19.9 | 11.3 |
| **Sutter County** | | | |
| Stationary Sources | 3.6 | 3.9 | 3.9 |
| Area Sources | 0.9 | 0.8 | 0.8 |
| Mobile Sources | 14.3 | 12.9 | 6.9 |
| **Yuba County** | | | |
| Stationary Sources | 0.7 | 0.7 | 0.7 |
| Area Sources | 0.5 | 0.5 | 0.5 |
| Mobile Sources | 6.2 | 6.6 | 4.9 |
| **Glenn County** | | | |
| Stationary Sources | 3.5 | 3.6 | 3.6 |
| Area Sources | 0.1 | 0.1 | 0.1 |
| Mobile Sources | 7.6 | 6.2 | 3.7 |
| **Colusa County** | | | |
| Stationary Sources | 5.1 | 5.1 | 5.0 |
| Area Sources | 0.9 | 0.9 | 0.9 |
| Mobile Sources | 8.4 | 6.7 | 4.0 |

Table 13 (cont.)

| **Plumas County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 1.8 | 1.8 | 1.8 |
| Area Sources | 0.4 | 0.4 | 0.4 |
| Mobile Sources | 4.8 | 4.3 | 3.7 |
| **Tehama County** | | | |
| Stationary Sources | 1.8 | 1.8 | 1.8 |
| Area Sources | 0.5 | 0.5 | 0.5 |
| Mobile Sources | 17.6 | 13.6 | 7.5 |

**Population Density and Degree of Urbanization**

According to the U.S. Census Bureau, the city of Chico has a 2006 population of 73,316. The population of Butte County in 2006 is approximately 215,881 based on 2000 Census data. This represents a 6 percent increase in population since 2000, and a 16 percent increase since 1990.

**Table 14: Population Butte County and City of Chico**

| **Butte County** | **1990** | **2000** | **2006** |
|---|---|---|---|
| Population | 182,120 | 203,171 | 215,881 |
| Population density | 111 persons/sq mile | 124 persons/sq mile | 132 persons/sq mile |
| **City of Chico** | | | |
| Population | 40,079 | 59,954 | 73,316 |
| Population density | 1,336 persons/sq mile | 1,998 persons/sq mile | 2,444 persons/sq mile |

**Traffic and Commuting Patterns**

The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. Traffic is expected to increase by 13 percent from 2005 to 2010, and by 30 percent by 2020 in Butte County. Vehicle miles traveled in Butte County is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources is expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

**Table 15: Average Daily Vehicle Miles Traveled Butte County**

| | **1990** | **2000** | **2005** | **2010** | **2015** | **2020** |
|---|---|---|---|---|---|---|
| Ave. Daily VMT/1000 | 4320 | 4496 | 4996 | 5762 | 6456 | 7138 |

**Expected Growth**

Butte County is expected to grow by 5 percent from 2005 to 2010, and by 12 percent by 2020. Population growth in surrounding areas is not expected to contribute to PM2.5 concentrations in Chico. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

**Table 16: Projected Future Population Butte County**

| | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|
| Population | 203,855 | 215,558 | 228,020 | 244,375 | 260,730 |

**Level of Control of Emissions Sources**

The city of Chico has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Valley Basinwide Air Pollution Control Council, which includes Butte County AQMD, administers a smoke management program for open burning consistent with ARB's statewide regulation. Areas surrounding Butte County have similar level of control regarding smoke management and control of NOx sources.

## City of Calexico within the Imperial County Air Pollution Control District

**Jurisdictional Boundary**

The presumptive boundary for the PM2.5 nonattainment area includes the City of Calexico, under the jurisdiction of the Imperial County Air Pollution Control District, and within the Salton Sea Air Basin.

ARB staff believes that the Calexico city level nonattainment boundary is appropriate due to the unique international pollutant transport problem between Calexico and Mexicali, Mexico. The two key components of PM2.5 are ammonium nitrate and organic carbon. Ammonium nitrate is a regional pollutant primarily derived from reactions with NOx emissions from mobile sources. ARB regulates sources of NOx emissions at a statewide level. Organic carbon is more localized and can be effectively controlled at the district level. However, we have no jurisdiction over these pollutant emission sources in Mexico.

**Air Quality**

Our initial recommendation for the city of Calexico is based on ambient PM2.5 concentrations measured from 2004 through 2006. Four monitoring sites throughout Imperial County monitor for PM2.5, however only two sites – Calexico-Ethel Street and El Centro-9$^{th}$ Street – have sufficient data to support designations. Our nonattainment recommendation is based on a design value of 40 ug/m3 measured at the Calexico-Ethel Street monitoring site. The El Centro monitoring site is well below the federal standard with a design value of 25 ug/m3.

Areas surrounding Imperial County include San Diego County to the west, Riverside County to the north, Arizona to the east, and Mexico to the south.

Exceedances of the PM2.5 standard in Riverside are included in the nonattainment area for the South Coast Air Pollution Control District. San Diego County is in attainment of the standard with a design value of 28 ug/m3 measured at the Chula Vista monitoring site.

The chemical makeup of PM2.5 in Calexico is dominated by organic carbon and ammonium nitrate. Figure 12 illustrates the seasonal pattern and chemical composition of PM2.5 at the Calexico-Ethel Street site with highest concentrations occurring in the winter time. Organic carbon is the largest component of PM2.5 and increases considerably during the winter months, however, it is significant throughout the year. Waste burning is prevalent throughout Mexicali and contributes to the year-round organic carbon concentrations. As shown in Figure 13, organic carbon accounts for roughly 48 percent of the 2004 – 2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 22 percent of the average composition on exceedance days. The primary source of ammonium nitrate is motor vehicles, which are regulated statewide by ARB. The motor vehicle fleets in Calexico and Mexicali differ substantially. Calexico vehicle fleets are equipped with state of the art emission control technologies. In contrast, Mexicali has a large number of late model vehicles lacking emission controls. The Calexico/Mexicali border is a major corridor for vehicle traffic resulting in a significant amount of motor vehicle emissions.

Figure 12: Seasonal Pattern of PM2.5 Chemical Components

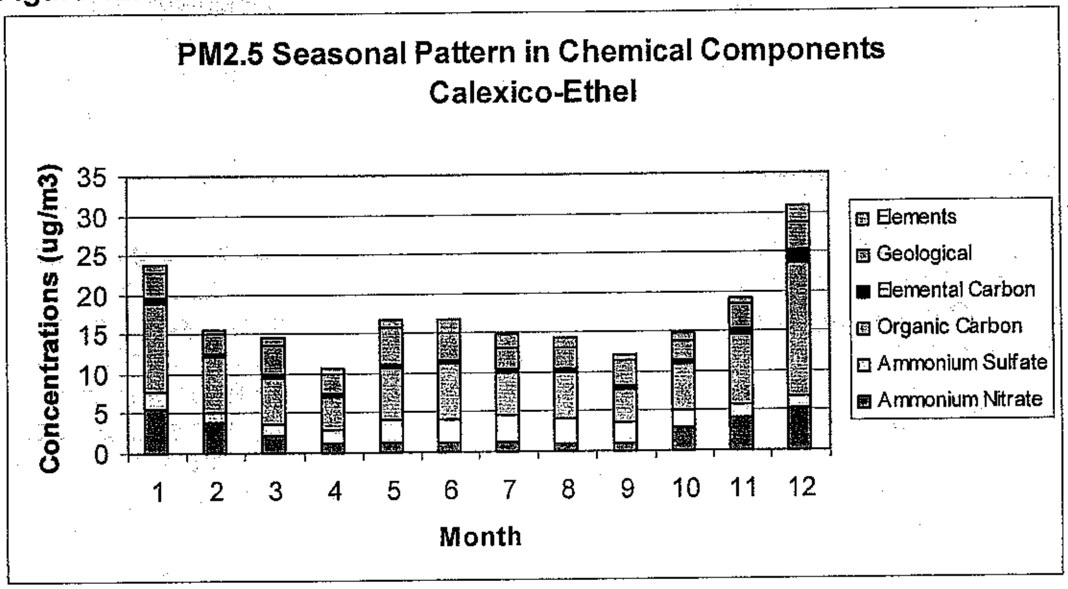
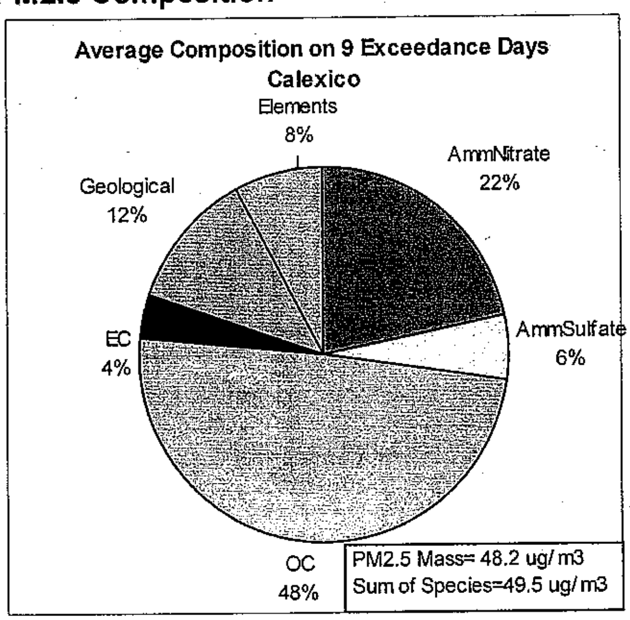



Figure 13: Ave. PM2.5 Composition




## Geography/Topography/Meteorology

Imperial County is located within the Salton Sea Air Basin along with the desert portion of Riverside County. Imperial County consists of 4,175 square miles, bordering Mexico to the south, Riverside County to the north, San Diego County to the west, and the State of Arizona on the east.

The Imperial Valley is a part of the larger Salton Trough. Also included in the Salton Trough is the western half of the Mexicali Valley and the Colorado River delta in Mexico. This trough is a very flat basin surrounded by mountains: the Peninsular Ranges to the west, the Chocolate, Orocopia and Cargo Muchacho Mountains to the east. Most of the trough is below seas level and is predominantly desert with agricultural land.

Climatic conditions in the Salton Sea Air Basin are governed by the large-scale sinking and warming air in the subtropical high-pressure center of the Pacific Ocean. The high-pressure ridge blocks most mid-latitude storms except in the winter when the high-pressure ridge is weakest and farthest south. Similarly, the coastal mountains prevent the intrusion of any cool damp marine air from the coast. Because of the weakened storms and the mountainous barrier, the Salton Sea Air Basin has hot summers, mild winters, and little rainfall. The flat terrain of the valley and the strong temperature differentials, created by intense solar heating produces moderate winds and deep thermal convection.

**Emissions**

The presumptive boundary for the PM2.5 nonattainment area includes the City of Calexico in Imperial County under the jurisdiction of the Imperial County Air Pollution Control District. Calexico (and Mexicali) are distinct from the rest of Imperial County based on the distribution and nature of emission sources. Imperial County is largely rural with widespread agricultural activity. ARB staff believes that violation of the PM2.5 standard in Calexico results from emissions in the densely populated international Calexico/Mexicali border region. The level of urban activity and PM2.5 pollution in the Calexico/Mexicali area are distinct and not representative of the rest of Imperial County.

**Table 17: NOx Winter Emissions Imperial and Surrounding Counties**

| **Imperial County** | **2006** | **2010** | **2020** |
|---|---|---|---|
| Stationary Sources | 5.5 | 5.7 | 6.1 |
| Area Sources | 1.0 | 0.9 | 0.9 |
| Mobile Sources | 33.3 | 26.5 | 18.8 |
| **Riverside County** | | | |
| Stationary Sources | 11.6 | 12.1 | 14.2 |
| Area Sources | 3.5 | 3.4 | 3.9 |
| Mobile Sources | 180.7 | 134.6 | 76.2 |
| **San Diego County** | | | |
| Stationary Sources | 8.8 | 10.8 | 12.0 |
| Area Sources | 3.7 | 3.7 | 3.7 |
| Mobile Sources | 205.4 | 172.7 | 132.9 |

**Population Density and Degree of Urbanization**

From an air quality perspective, Calexico and Mexicali, Mexico form one urbanized region divided by an international border. According to 2000 U.S.

Census data, Calexico's population in 2000 was approximately 27,000. The official Mexican Census placed Mexicali's population in 2000 at 760,000, with 3 percent annual growth expected. In 2000, the entire Imperial County population was approximately 143,000. Considering the geographic size of the two areas as well, the Mexicali population density is two and a half times the density for all of Imperial County.

**Table 18: Imperial County Population**

| | 1990 | 2000 | 2005 |
|---|---|---|---|
| Population | 110100 | 143595 | 162599 |
| Population Density | 26 persons/sq mile | 34 persons/sq mile | 39 persons/sq mile |

**Table 19: City of Calexico Population**

| | 1990 | 2000 | 2006 |
|---|---|---|---|
| Population | 18633 | 27102 | 37243 |

**Table 20: Mexicali, Mexico Population**

| | 2000 | 2004 | 2006 |
|---|---|---|---|
| Population | 764602 | 866277 | 922077 |

**Traffic and Commuting Patterns**

Calexico/Mexicali is home to a busy U.S. – Mexico border crossing. In 1996, the border crossing handled almost 7 million vehicles. Mexicali has over three times as many motor vehicles as all of Imperial County.

**Expected Growth**

Imperial County is expected to grow by about 9 percent from 2005 to 2010, and by about 24 percent by 2020. The city of Calexico has experienced a rapid population growth from 1990 to 2000, growing by approximately 40 percent during that time period. An even more dramatic growth of 50 percent is projected for the 2000 – 2010 period. Nonetheless, this rapid growth in Calexico and Imperial County is overwhelmed by the population and projected growth of Mexicali. According to the State Government of Baja Mexico, the 2006 population based on a 2000 census is 922,077. Assuming a constant rate of growth from 2000, the 2010 population is estimated to be approximately 1,045,000, and the 2020 estimated population is approximately 1,433,000.

**Table 21: Imperial County Projected Growth**

| | 2000 | 2005 | 2010 | 2015 | 2020 |
|---|---|---|---|---|---|
| Population | 143,595 | 162,599 | 178,201 | 196,294 | 214,386 |

**Table 22: Mexicali, Mexico Projected Growth**

| | 2000 | 2006 | 2010 | 2020 |
|---|---|---|---|---|
| Population | 764,602 | 922,077 | 1,045,842 | 1,432,892 |

**Level of Control of Emissions Sources**
Imperial County has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Imperial County District administers a smoke management program for open burning consistent with ARB's statewide regulation. Vehicles in Mexicali are typically older than California vehicles and there is no in-use inspection program. Finally, Mexicali open burning is widespread and uncontrolled. This is particularly significant given the large organic fraction found in Calexico PM2.5.

Based on all of these factors, ARB staff has concluded that Calexico exceedances of the federal PM2.5 standards are the result of urban activity associated with the densely populated international Calexico/Mexicali border region. Within Imperial County, the level of urban activity is unique to the area and is not representative of the air quality of the rest of Imperial County or the Salton Sea Air Basin.

## Enclosure 4

## State of California
## Boundary Descriptions for Recommended Nonattainment Areas under the Federal PM2.5 Standards

### South Coast Air Basin

*Los Angeles County (part)* - that portion of Los Angeles County which lies south and west of a line described as follows: Beginning at the Los Angeles – San Bernardino County boundary and running west along the Township line common to Township 3 North and Township 2 North, San Bernardino Base and Meridian; then north along the range line common to Range 8 West and Range 9 West; then west along the Township line common to Township 4 North and Township 3 North; then north along the range line common to Range 12 West and Range 13 West to the southeast corner of Section 12, Township 5 North and Range 13 West; then west along the south boundaries of Sections 12, 11, 10, 9, 8, and 7, Township 5 North and Range 13 West to the boundary of the Angeles National Forest which is collinear with the range line common to Range 13 West and Range 14 West; then north and west along the Angeles National Forest boundary to the point of intersection with the Township line common to Township 7 North and Township 6 North (point is at the northwest corner of Section 4 in Township 6 North and Range 14 West); then west along the Township line common to Township 7 North and Township 6 North; then north along the range line common to Range 15 West and Range 16 West to the southeast corner of Section 13, Township 7 North and Range 16 West; then along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 7 North and Range 16 West; then north along the range line common to Range 16 West and Range 17 West to the north boundary of the Angeles National Forest (collinear with the Township line common to Township 8 North and Township 7 North); then west and north along the Angeles National Forest boundary to the point of intersection with the south boundary of the Rancho La Liebre Land Grant; then west and north along this land grant boundary to the Los Angeles-Kern County boundary.

*Orange County*

*Riverside County (part)* - that portion of Riverside County which lies to the west of a line described as follows: Beginning at the Riverside - San Diego County boundary and running north along the range line common to Range 4 East and Range 3 East, San Bernardino Base and Meridian; then east along the Township line common to Township 8 South and Township 7 South; then north along the range line common to Range 5 East and Range 4 East; then west along the Township line common to Township 6 South and Township 7 South to the southwest corner of Section 34, Township 6 South, Range 4

East; then north along the west boundaries of Sections 34, 27, 22, 15, 10, and 3, Township 6 South, Range 4 East; then west along the Township line common to Township 5 South and Township 6 South; then north along the range line common to Range 4 East and Range 3 East; then west along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 5 South, Range 3 East; then north along the range line common to Range 2 East and Range 3 East; to the Riverside – San Bernardino County line.

*San Bernardino County (part)* - that portion of San Bernardino County which lies south and west of a line described as follows: Beginning at the San Bernardino - Riverside County boundary and running north along the range line common to Range 3 East and Range 2 East, San Bernardino Base and Meridian; then west along the Township line common to Township 3 North and Township 2 North to the San Bernardino - Los Angeles County boundary.

**San Joaquin Valley**

*San Joaquin County*
*Stanislaus County*
*Merced County*
*Madera County*
*Fresno County*
*Kings County*
*Tulare County*
*Kern County (part)* - That portion of Kern County which lies west and north of a line described as follows: Beginning at the Kern-Los Angeles County boundary and running north and east along the northwest boundary of the Rancho La Libre Land Grant to the point of intersection with the range line common to R. 16 W. and R. 17 W., San Bernardino Base and Meridian; north along the range line to the point of intersection with the Rancho El Tejon Land Grant boundary; then southeast, northeast, and northwest along the boundary of the Rancho El Tejon Land Grant to the northwest corner of S. 3, T. 11 N., R. 17 W.; then west 1.2 miles; then north to the Rancho El Tejon Land Grant boundary; then northwest along the Rancho El Tejon line to the southeast corner of S. 34, T. 32 S., R. 30 E., Mount Diablo Base and Meridian; then north to the northwest corner of S. 35, T. 31 S., R. 30 E.; then northeast along the boundary of the Rancho El Tejon Land Grant to the southwest corner of S. 18, T. 31 S., R. 31 E.; then east to the southeast corner of S. 13, T. 31 S., R. 31 E.; then north along the range line common to R. 31 E. and R. 32 E., Mount Diablo Base and Meridian, to the northwest corner of S. 6, T. 29 S., R. 32 E.; then east to the southwest corner of S. 31, T. 28 S., R. 32 E.; then north along the range line common to R. 31 E. and R. 32 E. to the northwest corner of S. 6, T. 28 S., R. 32 E., then west to the southeast corner of S. 36, T. 27 S., R. 31 E., then north along the range line common to R. 31 E. and R. 32 E. to the Kern-Tulare County boundary.

**Sacramento County**

**City of Calexico**

*ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.*

**City of Chico**

*ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.*

**Combined cities of Marysville and Yuba City**

*ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.*

**San Francisco Bay Area**

*Sonoma County (part)*- That portion of Sonoma County which lies south and east of a line described as follows: Beginning at the southeasterly corner of the Rancho Estero Americano, being on the boundary line between Marin and Sonoma Counties, California; thence running northerly along the easterly boundary line of said Rancho Estero Americano to the northeasterly corner thereof, being an angle corner in the westerly boundary line of Rancho Canada de Jonive; thence running along said boundary of Rancho Canada de Jonive westerly, northerly and easterly to its intersection with the easterly line of Graton Road; thence running along the easterly and southerly line of Graton Road, northerly and easterly to its intersection with the easterly line of Sullivan Road; thence running northerly along said easterly line of Sullivan Road to the southerly line of Green Valley Road; thence running easterly along the said southerly line of Green Valley Road and easterly along the southerly line of State Highway 116, to the westerly line of Vine Hill Road; thence running along the westerly and northerly line of Vine Hill Road, northerly and easterly to its intersection with the westerly line of Laguna Road; thence running northerly along the westerly line of Laguna Road and the northerly projection thereof to the northerly line of Trenton Road; thence running westerly along the northerly line of said Trenton Road to the easterly line of Trenton-Healdsburg Road; thence running northerly along said easterly line of Trenton-Healdsburg Road to the easterly line of Eastside Road; thence running northerly along said easterly line of Eastside Road to its intersection with the southerly line of Rancho Sotoyome; thence running easterly along said southerly line of Rancho Sotoyome to its intersection with the Township line common to Townships 8 and 9 North, M.D.M.; thence running easterly along said township line to its intersection with the boundary line between Sonoma and Napa Counties.

*Napa County*

*Solano County (part)* - Portion of Solano County which lies south and west of a line described as follows: Beginning at the intersection of the westerly boundary of Solano County and the 1/4 section line running east and west through the center of Section 34, T6N, R2W, M.D.B. & M., thence east along said 1/4 section line to the east boundary of Section 36, T6N, R2W, thence south 1/2 mile and east 2.0 miles, more or less, along the west and south boundary of Los Putos Rancho to the northwest corner of Section 4, T5N, R1W, thence east along a line common to T5N and T6N to the northeast corner of Section 3, T5N, R1E, thence south along section lines to the southeast corner of Section 10, T3N, R1E, thence east along section lines to the south 1/4 corner of Section 8, T3N, R2E, thence east to the boundary between Solano and Sacramento Counties.

*Contra Costa County*
*Alameda County*
*Santa Clara County*
*San Mateo County*
*San Francisco County*
*Marin County*

Enclosure 5

**State of California**

**PM2.5 Monitoring Data Summary**

(based on 2004 - 2006)

| Basin | County | Site | PM2.5 98th percentile 24-hour (ug/m3) | | | 3-Year Average 24-Hour 98th | Data Complete/ Valid |
|---|---|---|---|---|---|---|---|
| | | | 2004 | 2005 | 2006 | | |
| Great Valley Basin | Inyo | Keeler-Cerro Gordo Road | 22.0 | 13.0 | 22.0 | 19 | No/No |
| | Mono | Mammoth Lakes-Gateway HC | 26.0 | 27.0 | | | No/No |
| Lake County | Lake | Lakeport-Lakeport Blvd. | 9.0 | 10.5 | 21.4 | 14 | Yes/Yes |
| Lake Tahoe | El Dorado | South Lake Tahoe-Sandy Way | 20.0 | | | | No/No |
| Mountain Counties | Calaveras | San Andreas-Gold Strike Road | 21.0 | 18.0 | 23.0 | 21 | Yes/Yes |
| | Nevada | Grass Valley-Litton Building | 10.0 | 10.0 | 24.0 | 15 | No/No |
| | | Truckee-Fire Station | 18.0 | 16.0 | 15.0 | 16 | Yes/Yes |
| | Plumas | Portola-161 Nevada Street | 33.0 | 26.0 | 31.0 | 30 | Yes/Yes |
| | | Quincy-N Church Street | 28.0 | 27.0 | 25.0 | 27 | No/No |
| Mohave Desert | Kern | Mojave-923 Poole Street | 16.8 | 15.7 | 21.3 | 18 | No/No |
| | | Ridgecrest-100 West California Avenue | 15.2 | 16.2 | 13.0 | 15 | No/No |
| | Los Angeles | Lancaster-43301 Division Street | 15.0 | 16.0 | 13.0 | 15 | No/No |
| | San Bernardino | Victorville-14306 Park Avenue | 20.0 | 19.0 | 19.0 | 19 | No/No |
| North Coast | Humboldt | Eureka-I Street | 23.1 | 31.8 | 35.0 | 30 | No/No |
| | | Eureka-Jacobs | | | 21.2 | | No/No |
| | Mendocino | Ukiah-County Library | 14.4 | 15.2 | 17.4 | 16 | Yes/Yes |
| North Central Coast | Monterey | Salinas #3 | 15.5 | 14.2 | 13.0 | 14 | No/No |
| | Santa Cruz | Santa Cruz-2544 Soquel Avenue | 14.9 | 21.7 | 12.6 | 16 | No/No |
| Northeast Plateau | Siskiyou | Yreka-Foothill Drive | | 26.0 | 22.0 | | No/No |
| South Coast | Los Angeles | Azusa | 53.8 | 53.2 | 38.4 | 48 | No/Yes |
| | | Burbank-W Palm Avenue | 49.3 | 50.5 | 43.4 | 48 | No/Yes |
| | | Long Beach-East Pacific Coast Highway | 42.0 | 37.7 | 35.2 | 38 | No/Yes |
| | | Los Angeles-North Main Street | 54.3 | 53.3 | 38.9 | 49 | Yes/Yes |
| | | Lynwood | 53.0 | 48.4 | 44.4 | 49 | Yes/Yes |
| | | North Long Beach | 45.8 | 41.4 | 34.9 | 41 | No/Yes |
| | | Pasadena-S Wilson Avenue | 46.5 | 43.0 | 32.0 | 41 | Yes/Yes |
| | | Pico Rivera | 52.1 | 51.4 | | | No/No |
| | | Pico Rivera-4144 San Garbriel | | 58.2 | 43.0 | | No/No |
| | | Reseda | 53.2 | 35.7 | 31.9 | 40 | No/Yes |
| | Orange | Anaheim-Pampas Lane | 48.2 | 41.8 | 40.5 | 44 | Yes/Yes |
| | | Mission Viejo-26081 Via Pera | 38.5 | 31.4 | 25.7 | 32 | No/No |
| | Riverside | Riverside-5130 Poinsettia Place | | | 52.5 | | No/No |
| | | Riverside-Magnolia | 53.7 | 41.0 | 47.7 | 47 | No/Yes |
| | | Riverside-Rubidoux | 59.5 | 58.3 | 54.4 | 57 | No/Yes |
| | San Bernardino | Big Bear City-501 W. Valley Blvd | 23.1 | 38.7 | 40.0 | 34 | No/No |
| | | Fontana-Arrow Highway | 62.6 | 48.2 | 43.7 | 52 | No/Yes |
| | | Ontario-1408 Francis Street | 59.9 | 49.5 | 41.5 | 50 | No/Yes |
| | | San Bernardino-4th Street | 72.4 | 43.4 | 49.0 | 55 | No/Yes |
| South Central Coast | San Luis Obispo | Atascadero-Lewis Avenue | 19.6 | 25.2 | 22.2 | 22 | Yes/Yes |
| | | San Luis Obispo-3220 South Higuera St | | 11.4 | 21.4 | | No/No |
| | | San Luis Obispo-Marsh Street | 12.7 | 18.6 | | | No/No |
| | Santa Barbara | Santa Barbara-700 East Canon Perdido | 22.2 | 28.3 | 23.9 | 25 | No/No |
| | | Santa Maria-906 S Broadway | 12.9 | 29.8 | 12.7 | 18 | No/No |
| | Ventura | El Rio-Rio Mesa School #2 | 27.0 | 23.8 | 23.5 | 25 | Yes/Yes |
| | | Piru-3301 Pacific Avenue | 22.4 | 20.3 | 21.4 | 21 | Yes/Yes |
| | | Simi Valley-Cochran Street | 36.7 | 26.3 | 27.6 | 30 | Yes/Yes |
| | | Thousand Oaks-Moorpark Road | 35.4 | 22.5 | 23.4 | 27 | Yes/Yes |
| San Diego County | San Diego | Chula Vista | 30.7 | 30.2 | 24.0 | 28 | Yes/Yes |
| | | El Cajon-Redwood Avenue | 36.3 | 27.4 | 25.7 | 30 | No/No |
| | | Escondido-E Valley Parkway | 37.4 | 32.2 | 28.3 | 33 | No/No |
| | | San Diego-1110 Beardsley Street | | 33.7 | 28.4 | | No/No |
| | | San Diego-12th Avenue | 33.7 | 26.6 | | | No/No |
| | | San Diego-Overland Avenue | 25.2 | 23.1 | 20.8 | 23 | No/No |
| San Francisco Bay Area | Alameda | Fremont-Chapel Way | 33.0 | 27.6 | 30.4 | 30 | No/No |
| | | Livermore-793 Rincon Avenue | 35.3 | 28.7 | 36.6 | 34 | No/Yes |
| | Contra Costa | Concord-2956 A Treat Blvd | | 40.9 | 16.0 | | No/No |
| | | Concord-2975 Treat Blvd | 38.1 | 33.4 | 33.6 | 35 | No/Yes |
| | San Francisco | San Francisco-Arkansas Street | 32.2 | 32.6 | 27.8 | 31 | No/No |
| | San Mateo | Redwood City | 27.9 | 29.4 | 30.9 | 29 | No/No |
| | Santa Clara | San Jose-Jackson Street | 39.8 | 39.8 | 36.0 | 39 | No/Yes |
| | | San Jose-Tully Road | 36.5 | 38.7 | 23.8 | 33 | No/No |
| | Solano | Vallejo-304 Tuolumne Street | 36.9 | 35.6 | 34.3 | 36 | No/Yes |
| | Sonoma | Santa Rosa-5th Street | 25.2 | 29.7 | 31.2 | 29 | No/No |

Enclosure 5

**State of California**

**PM2.5 Monitoring Data Summary**

(based on 2004 - 2006)

| Basin | County | Site | PM2.5 98th percentile 24-hour (ug/m3) | | | 3-Year Average 24-hour 98th | Data Complete/ Valid |
|---|---|---|---|---|---|---|---|
| | | | 2004 | 2005 | 2006 | | |
| San Joaquin Valley | Fresno | Clovis-N Villa Avenue | 52.4 | 63.0 | 51.3 | 56 | No/Yes |
| | | Fresno-1st Street | 52.0 | 71.0 | 51.0 | 58 | Yes/Yes |
| | | Fresno-Hamilton and Winery | 49.4 | 71.2 | 55.0 | 59 | Yes/Yes |
| | Kern | Bakersfield-410 E Planz Road | 47.6 | 66.4 | 64.7 | 60 | No/Yes |
| | | Bakersfield-5558 California Avenue | 61.5 | 63.2 | 60.5 | 62 | No/Yes |
| | | Bakersfield-Golden State Highway | 53.9 | 74.9 | 64.4 | 64 | Yes/Yes |
| | Kings | Corcoran-Patterson Avenue | 49.4 | 74.5 | 50.1 | 58 | Yes/Yes |
| | Merced | Merced-2334 M Street | 43.0 | 48.3 | 43.8 | 45 | Yes/Yes |
| | San Joaquin | Stockton-Hazelton Street | 36.0 | 44.0 | 42.0 | 41 | Yes/Yes |
| | Stanislaus | Modesto-14th Street | 45.0 | 55.0 | 52.0 | 51 | Yes/Yes |
| | Tulare | Visalia-N Church Street | 54.0 | 65.0 | 50.0 | 56 | No/Yes |
| Salton Sea | Imperial | Brawley-220 Main Street | 23.6 | 23.5 | 20.3 | 22 | No/No |
| | | Calexico-Ethel Street | 31.9 | 41.1 | 46.0 | 40 | No/Yes |
| | | El Centro-9th Street | 25.1 | 22.1 | 27.1 | 25 | Yes/Yes |
| | Riverside | Indio-Jackson Street | 26.8 | 25.0 | 19.0 | 24 | No/No |
| | | Palm Springs-Fire Station | 23.3 | 25.0 | 15.8 | 21 | No/No |
| Sacramento Valley | Butte | Chico-Manzanita Avenue | 54.0 | 54.0 | 59.0 | 56 | Yes/Yes |
| | Colusa | Colusa-Sunrise Blvd | 34.0 | 16.0 | 30.0 | 27 | Yes/Yes |
| | Placer | Roseville-N Sunrise Blvd | 30.0 | 28.0 | 36.0 | 31 | Yes/Yes |
| | Sacramento | Sacramento-Del Paso Manor | 42.0 | 49.0 | 55.0 | 49 | Yes/Yes |
| | | Sacramento-Health Dept Stockton Blvd | 35.0 | 42.0 | 39.0 | 39 | Yes/Yes |
| | | Sacramento-T Street | 37.0 | 47.0 | 39.0 | 41 | No/Yes |
| | Shasta | Redding-Health Dept Roof | 18.0 | 19.0 | 29.0 | 22 | Yes/Yes |
| | Sutter | Yuba City-Almond Street | 38.0 | 42.0 | 41.0 | 40 | Yes/Yes |
| | Yolo | Woodland-Gibson Road | 31.0 | 24.0 | 36.0 | 30 | Yes/Yes |

# Attachment G

Linda S. Adams
*Secretary for Environmental Protection*

# Air Resources Board

**Mary D. Nichols, Chairman**
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

**Arnold Schwarzenegger**
*Governor*

October 15, 2008

Mr. Wayne Nastri
Regional Administrator
Region 9
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, California 94105-3901

Dear Mr. Nastri:

This is in response to your letter to Governor Arnold Schwarzenegger, transmitting the United States Environmental Protection Agency's (U.S. EPA) modifications to the California Air Resources Board's (ARB) recommendations for area designations under the federal air quality standards for particulate matter 2.5 microns or less in diameter (PM2.5).

We based the original recommendations on ambient PM2.5 data measured from 2004 through 2006, considering both emissions impacting elevated PM2.5 levels and public exposure to those levels. Reevaluation of these recommendations, based on 2005 through 2007 data, confirms our original assessment and recommendations for nonattainment area boundaries. We request that U.S. EPA modify the proposed nonattainment area boundaries to be consistent with California's recommendations. At issue are the proposed boundaries for the City of Calexico, Sacramento County, City of Chico, and the combined Cities of Yuba City/Marysville. We are in agreement on the boundaries for the South Coast Air Basin, San Joaquin Valley Air Basin, and San Francisco Bay Area. We have provided additional information to document the extent of international transport which causes localized impacts in Imperial County, and the localized impact of wood smoke in the other areas at issue.

An underlying premise for U.S. EPA's proposed PM2.5 boundaries is to provide consistency with existing ozone and PM10 nonattainment area boundaries. While that may be convenient from an administrative standpoint, the primary considerations in setting these boundaries should be scientific in nature. Our recommendations reflect the nature of the PM2.5 problem in each area. Where the problem is more localized than regional, we have recommended technically based nonattainment area boundaries that differ from ozone area boundaries. We note several areas elsewhere in the country where proposed designations are not consistent with ozone and PM10 nonattainment area boundaries, such as those in the New York, New Jersey, Connecticut, and Tennessee. We request the same consideration.

If you have any questions, please call Ms. Lynn Terry, Deputy Executive Officer, at (916) 322-2739, or have your staff contact Ms. Karen Magliano, Chief, Air Quality Data Branch, at (916) 322-7137.

Sincerely,

James N. Goldstene
Executive Officer

Enclosures

cc: See next page.

cc: Brad Poirez, APCO
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Lynn Terry
Air Resources Board

Karen Magliano
Air Resources Board

## Technical Support

### PM2.5 Designation Recommendations

The California Air Resources Board (ARB) continues to support our original recommendations transmitted to the United States Environmental Protection Agency (U.S. EPA) in December 2007. The U.S. EPA responded to the recommendation (U.S. EPA Response) on August 18, 2008. This document supplies additional support for ARB's recommendations.

In a memorandum dated June 8, 2007 from Robert Meyers, Acting Assistant Administrator, U.S. EPA identified the most important factors for States and Tribes to consider when making area designation recommendations. Specifically, demonstrations should show that,

1. violations are not occurring in the excluded portions of the recommended area, and
2. the excluded portions do not contain emission sources that contribute to the observed violations.

This addendum will address those two requirements in regard to the recommended nonattainment areas. In addition, prior to discussing each individual area, ARB is providing other issues that U.S. EPA should take into consideration when making the final nonattainment boundary decisions.

### Size and Nature of Affected Areas

One of the primary issues that must be addressed when discussing the boundaries of a nonattainment area in California is the large size of California counties versus other states. The average area of a California county is 2,822 square miles, yet the average county size in the United States is 622 square miles. Alaska and Arizona are the only states with larger average county size (Table 1). The average California county is over 4 ½ times the average U.S. county; many as large, if not larger, than entire states. In many cases, California counties contain one or two urbanized regions and large stretches of sparsely populated areas.

Much of the nine-factor analysis utilized by U.S. EPA to determine PM2.5 nonattainment areas is based on a county level. This presents some unusual challenges for California. For instance, applying county-wide vehicle miles traveled (VMT) statistics to a large California county misrepresents differences that may exist in VMT urban and rural areas in that county, or between two widely separated urban areas in the same county. Throughout this submittal, we offer alternative approaches to analyzing the nine factors when county size presents a particular problem. This problem is most evident in Imperial County where the three main urban areas represent only one percent of the county (in square miles) recommended as a nonattainment area. The remaining 99 percent of the county is sparsely populated.

Table 1. Examples of County Area by State

| State | Mean County Area (mi²) |
|---|---|
| Alaska | 39015 |
| Arizona | 7600 |
| *California* | 2822 |
| Texas | 1057 |
| New York | 880 |
| Connecticut | 693 |
| Iowa | 568 |
| Ohio | 509 |
| Tennessee | 444 |
| Georgia | 374 |
| Rhode Island | 243 |

**Consistent Nonattainment Areas**

Air quality planning in California is based primarily on air basin and air district boundaries if the pollution problem is of a regional nature. Although ARB generally uses a combination of air district and air basin lines to set the boundaries for areas violating California air quality standards, exceptions are made when a smaller area, such as a single city, exhibits an air quality issue distinct from the surrounding region. For example, due to the nature of the pollutant problem in Imperial County, only the City of Calexico is considered nonattainment for the State PM2.5 standard.

One of U.S. EPA's goals in designating nonattainment areas in California was to achieve a degree of consistency with existing ozone and PM10 nonattainment areas. Application of this goal in California led to differences between the State's recommended nonattainment areas and U.S. EPA's proposed designations. U.S. EPA expanded many of the State's recommended PM2.5 nonattainment areas boundaries to match 8-hour ozone nonattainment area boundaries. However, we do note areas throughout the country where U.S. EPA proposed PM2.5 nonattainment area designations are not consistent with existing 8-hour ozone nonattainment area boundaries. Examples are shown in Table 2.

Table 2. U.S. Examples of Excluded Areas Not Consistent With 8-Hour Ozone Nonattainment Boundaries

| Excluded County, State | Previous 8-hour Ozone Nonattainment Area |
|---|---|
| Warren County NJ | New York-N. New Jersey-Long Island, NY-NJ-CT |
| Cecil County MD | Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE |
| Salem County NJ | |
| Jefferson TN | Knoxville, TN |
| Sevier Counties TN | |
| Christian County KY | Clarksville-Hopkinsville, TN-KY |
| Geauga County OH | Cleveland-Akron-Lorain, OH |
| Clinton County OH | Cincinnati-Hamilton, OH-KY-IN |
| Knox and Madison Counties OH | Columbus, OH |

Some of these areas were excluded based on the nature of the pollutant. PM2.5 is comprised of both primary and secondary components; the primary being more localized. ARB requests that U.S. EPA recognize the technical basis for different boundaries for regional ozone and localized PM2.5.

## Additional Information – Area Specific

1. <u>City of Calexico, Imperial County Air Pollution Control District</u>

The only monitor in Imperial County violating the new federal PM2.5 standard is located in the City of Calexico. Data from air quality monitors in El Centro and Brawley, as shown in Figure 1-1, are well below the new standard and about 45% lower than Calexico (2007 Design Values are indicated in the colored circles). Calexico has 24% of the population of Imperial County within its boundaries (Table 1-1) with the second largest population and the highest population density. The largest population area, El Centro, only nine miles north of Calexico, is in attainment of the standard.

The majority of the county is largely unpopulated. Only 14% of the population resides outside of the urbanized areas, the majority of these still within the narrow area stretching from Mexico to the Salton Sea. Most of the population, however, lives in areas that attain the standard. Confining the nonattainment area to the City of Calexico would still ensure protection for the population exposed to unhealthy levels of PM2.5.

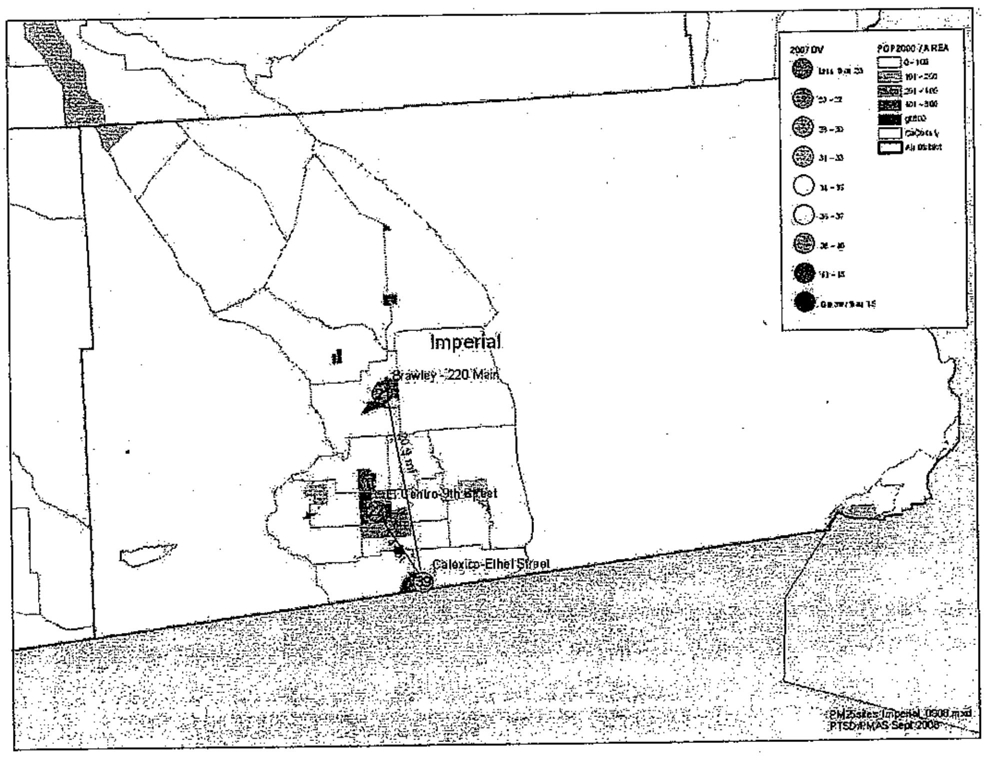


Figure 1-1: 2007 Design Values in Imperial County

The City of Calexico is located next to the Mexico international border. As seen in the satellite view in Figure 1-2, the urban area of Mexicali, Mexico is considerably larger than that of Calexico. Table 1-1 shows the disparity in both population and physical size; Calexico accounts for only 5% of the population and 4% of the land area of the combined Calexico/Mexicali urban area, a metropolis separated by a nonphysical international border. The population density of Imperial County is less than a fifth of the Municipality of Mexicali, in an area of roughly the same size. A similar situation is faced at the border area of Nogales, AZ (population: 21,746). The Mexican city of Nogales (population: 203,719), with a much higher population and population density, is separated from Nogales, AZ only by a political boundary. This population disparity was noted by U.S. EPA in considering the Nogales area as a focused nonattainment area for PM2.5, retaining the rest of Santa Cruz County in attainment. ARB believes that air quality in the City of Calexico is similarly overwhelmed by the much larger City of Mexicali across the border and requests similar consideration.

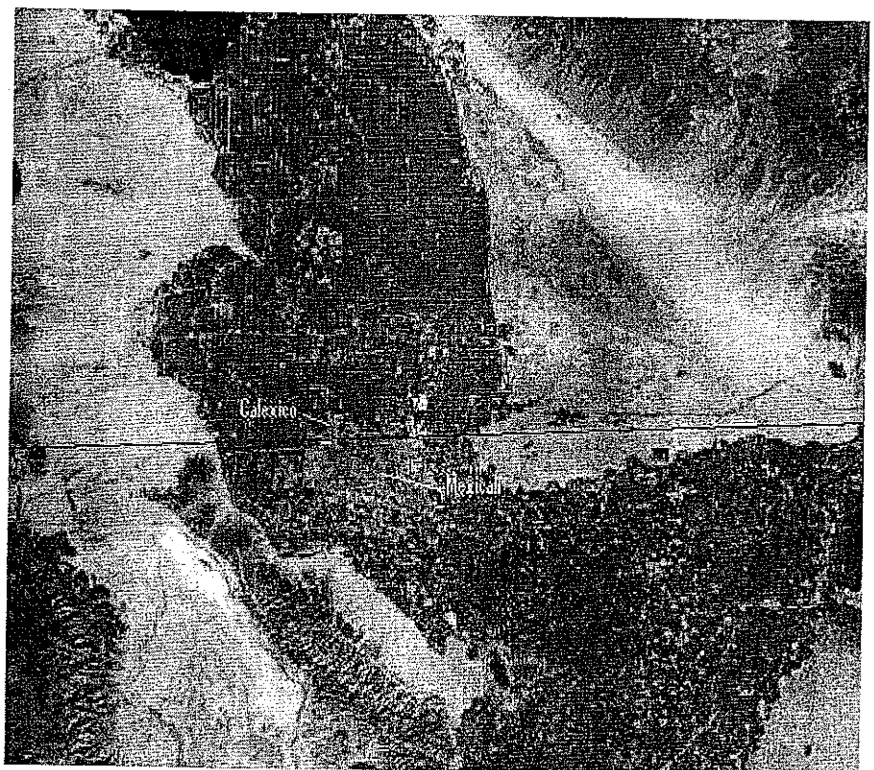


Figure 1-2: Calexico and Mexicali Satellite Image
*[Source: maps.google.com]*

Table 1-1: Population of Calexico/Mexicali Border Region

| Area | Population (2006 est.) | Area ($mi^2$) |
|---|---|---|
| Imperial County | 160,301 | 4,598 |
| El Centro | 40,563 | 10 |
| Calexico | 37,243 | 9 |
| Mexicali Municipality | 873,937 | 5,200 |
| Mexicali | 653,046 | 200 |

*[Data Source: U.S. Census [www.census.gov/; CONAPO [www.conapo.gob.mx]*

The U.S. EPA states, "Imperial County shows violations of the 24-hour PM2.5 standard. Therefore, this county is a candidate for a 24-hour PM2.5 nonattainment designation (U.S. EPA Response, p.8)." Calexico, the only violating area of Imperial County, comprises only 1% of the county area. When Imperial County was designated as nonattainment for both PM10 and ozone, consideration was given for both the regional nature of the pollution sources and the presence of violating monitors throughout the county. This is not the case, however, for PM2.5. Both the presence of a single violating monitor, as well as the impact from Mexicali, argue for a focused nonattainment area, as originally recommended by ARB.

The Imperial Valley operates as a channel running northwest to southeast. Wind flow patterns tend to flow along this channel, from the northwest into Mexicali, and from the southeast into Calexico. Although the geography of the Imperial Valley is such that there are no topographical barriers that separate the City of Calexico from the rest of Imperial County, the significantly lower concentrations to the north (Figure 1-1 and Table 1-2) show that distance is enough of a barrier to keep the northern urban population from being exposed to levels above the standard.

Table 1-2: Exceedance Days at Calexico-Ethel

| Date | Concentrations (ug/m3) | | |
|---|---|---|---|
| | **Calexico** | **El Centro** | **Brawley** |
| 12/12/05 | 67.6 | 57.9 | 19.9 |
| 12/18/05 | 41.1 | 34.1 | **37.8** |
| 1/8/06 | 44.8 | 12.7 | 20.3 |
| 1/14/06 | 49.6 | 23.2 | n/a |
| 1/17/06 | 37.1 | 16.4 | n/a |
| 12/22/06 | 46.0 | 16.5 | 11.7 |
| 12/25/06 | 68.8 | 9.6 | 8.5 |
| 12/5/06 | 52.7 | 20.9 | 19.5 |

Hysplit model results (U.S. EPA Response, Attachment 2) implied a contribution from emissions throughout Imperial County to elevated levels at the Calexico-Ethel site. As noted above, however, other sites in the county showed much lower concentrations during Calexico exceedance days, indicating that the high concentrations at Calexico were unlikely to be due to a northern influence. In fact, the two highest PM2.5 exceedance days coincide with PM10 exceedances being documented by the Imperial County Air Pollution Control District as due to transport from Mexicali.

The U.S. EPA noted two days with potential northern influence. ARB staff conducted further analysis using two-dimensional wind trajectory models (Figure 1-3). The first part of the figure (a) shows stagnant conditions present on January 8, 2006. The blue trajectory line indicates that the air parcel moved very little during the day. The second part of the figure (b), from January 17, 2006, shows a more northern flow, but concentrations at El Centro were half that of Calexico (no data available from Brawley on that day), indicating very limited influence from the northern portion of the county.

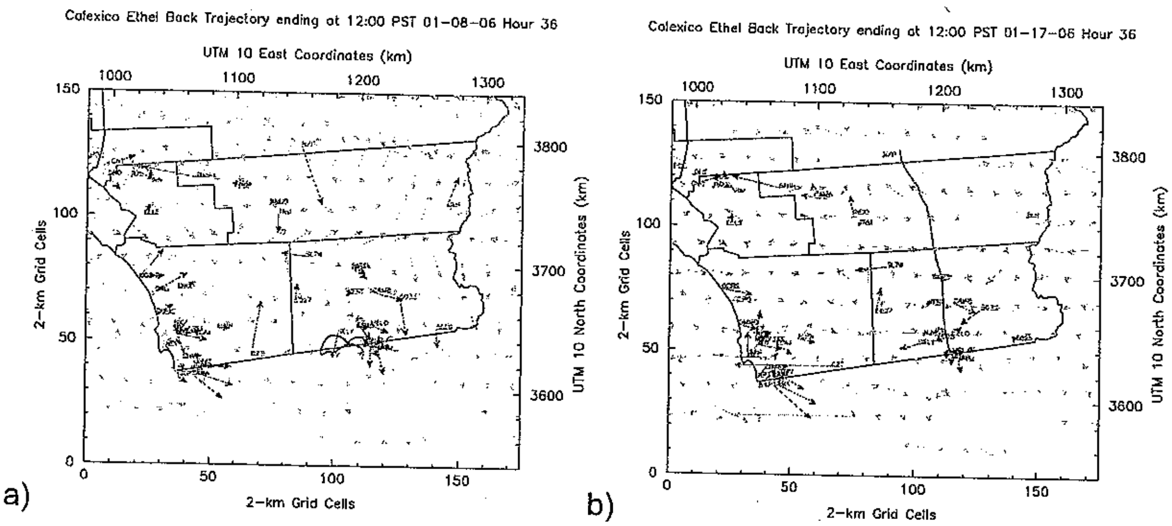


Figure 1-3: 2-D Wind Trajectory Model Results, Calexico-Ethel, Imperial County

Additionally, BAM concentrations on these two exceedance days show a strong correlation with wind from the south (Figure 1-4). The red boxes outline the flow from the south (90-270 degrees); the blue boxes indicate the increased PM2.5 concentrations associated with these winds.

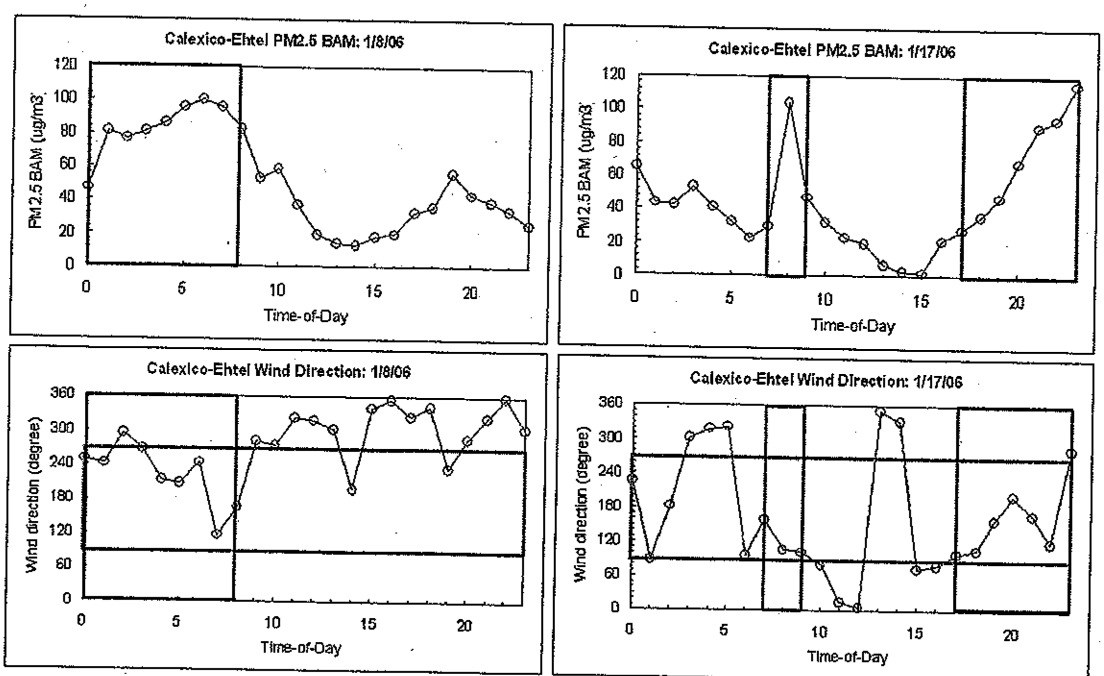


Figure 1-4: Correlation between PM2.5 BAM Concentrations and Wind Direction

Research into PM10 concentration differences between Mexicali and Calexico (Chow, et.al., 2000) showed that average cross-border transport of PM10 from Mexico was three times higher than from the U.S. The study showed that Mexicali's PM10 concentrations were almost double those at Calexico. Although the relative source contributions between the two sites were found to be similar, the absolute source contributions at the Mexicali site were three to seven times that at the Calexico site. The researchers suggested that increased charbroiling in Mexicali during the major holiday season (mid December to early January) accounted for the difference; the same period of time as the PM2.5 exceedances at Calexico-Ethel.

As noted in the U.S. EPA Response (Table 1, p.5) , the emissions inventory for Imperial County shows a 24% contribution from carbon. Chemical composition data for Calexico specifically from exceedance days at Calexico shows an organic carbon contribution of over 50% (Figure 1-5). The seasonal pattern (Figure 1-6) shows the strong wintertime increase in organic carbon. We believe the majority of these carbon emissions are the result of transport from the City and Municipality of Mexicali, Mexico, where residential trash and wood burning are largely unregulated. In addition, the majority of the exceedance days noted in Table 1-2 occurred during the December/January time period when there are increased volumes of smoke across the border, as evidenced in Figures 1-10 and 1-11. These emissions, while large, tend to remain in the local area, as shown by a comparison to PM2.5 concentrations at Brawley, a site further removed from the border influence (Figure 1-7). Very little variation in PM2.5 concentrations is seen throughout the year. Calexico, however, as indicated by the trend line shown in red, shows a distinct increase in winter.

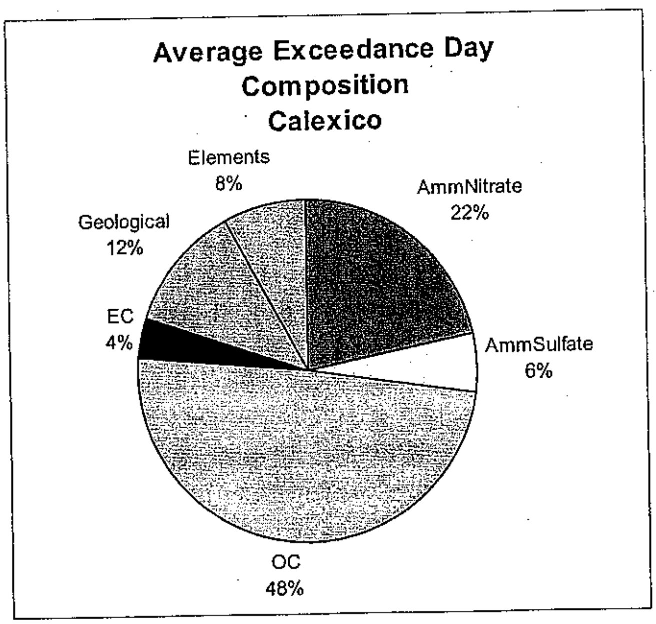


Figure 1-5: PM2.5 Composition, Calexico, Imperial County

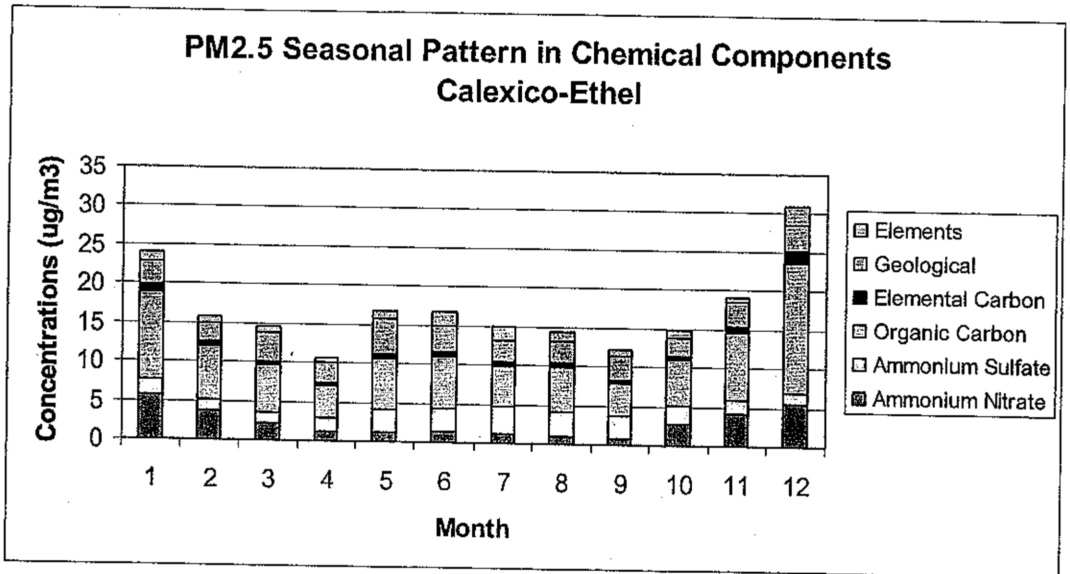


Figure 1-6: Seasonal Pattern of PM2.5 Composition, Calexico, Imperial County

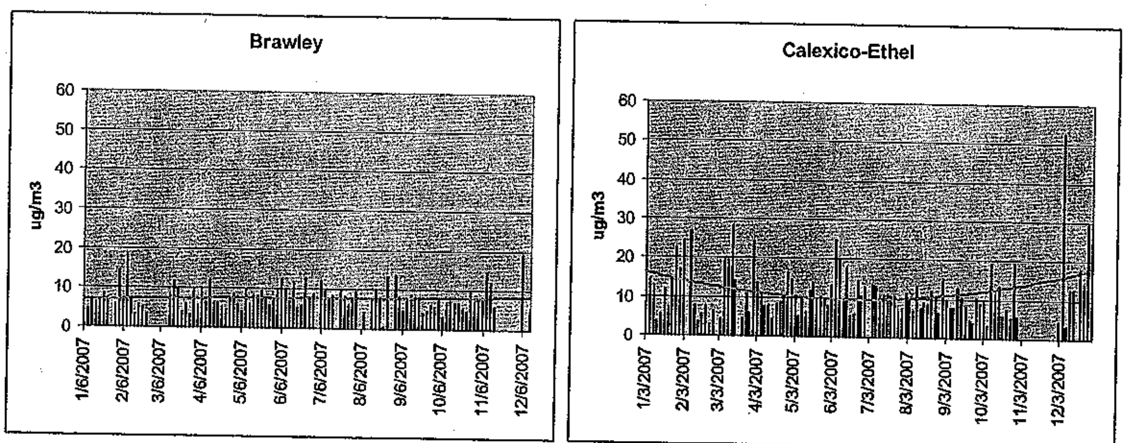


Figure 1-7: Seasonal variation in PM2.5 at two sites in Imperial County

Per a request in U.S. EPA Response, Table 1-3 includes 2005 Imperial County and Mexicali emissions. Imperial County PM2.5 emissions are higher than Mexicali mostly due to area sources, 65% due to windblown fugitive dust. In the absence of a more detailed inventory, it can be reasonably assumed that Calexico, with only 24% of the population of Imperial County, would account for less than half of the emissions of Imperial County as a whole. In addition, wind-blown dust emissions are not a factor during winter-time stagnation episodes. Table 1-3 illustrates the great disparity between Imperial County and Mexicali emissions. Mexicali total NOx emissions are twice those of Imperial, with SOx emissions are thirteen times those north of the border. A significant portion of the Mexicali emissions are from stationary sources. Figure 1-8 shows the large number of stationary sources located near the international border with several right on the border. In comparison, Figure 1-9 shows that there are only a few stationary sources (triangles) in Imperial County and none in the City of Calexico (blue squares are monitoring sites).

Table 1-3: 2005 Emissions Imperial County and Mexicali (tons/day)

| **Imperial County** | **NOx** | **SOx** | **PM2.5** |
|---|---|---|---|
| Stationary Sources | 7.1 | 0.2 | 1.3 |
| Area Sources | 0.9 | 0.1 | 37.5 |
| Mobile Sources | 30.2 | 0.6 | 1.7 |
| **Total** | **38.3** | **0.9** | **40.4** |
| **Mexicali** | | | |
| Stationary Sources | 39.4 | 12.7 | 0.4 |
| Area Sources | 3.7 | 0.5 | 18.5 |
| Mobile Sources | 35.8 | 0.6 | 3.3 |
| **Total** | **78.9** | **13.8** | **22.2** |

*[Source: Imperial County Emissions- ARB Almanac; Mexicali Emissions-ERG 2005 Mexicali Emissions Inventory Draft Final, 10/3/08]*

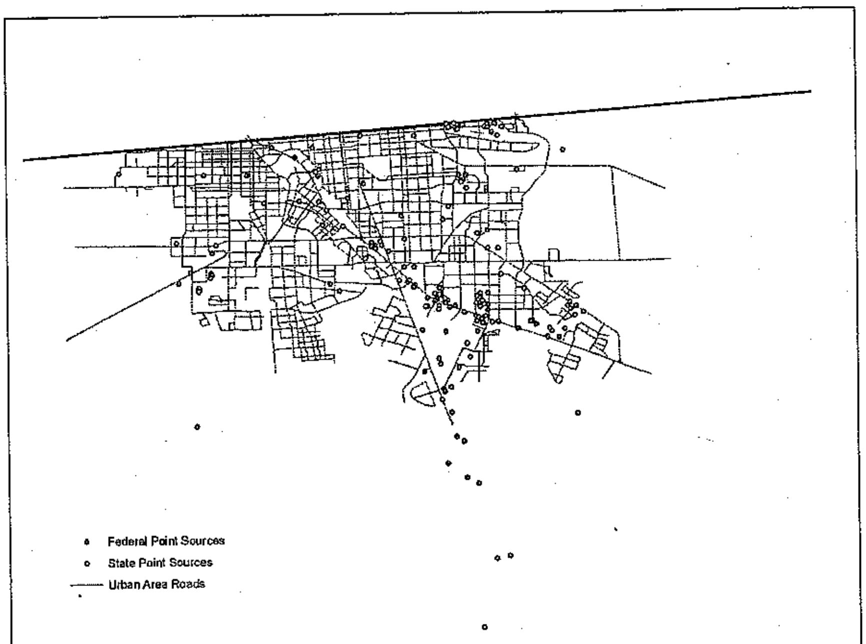


Figure 1-8: Location of Federal and State Jurisdiction Point Sources in the Urban Portion of Mexicali

*[Source: Mexicali Emissions-ERG 2005 Mexicali Emissions Inventory Draft Final, 10/3/08]*

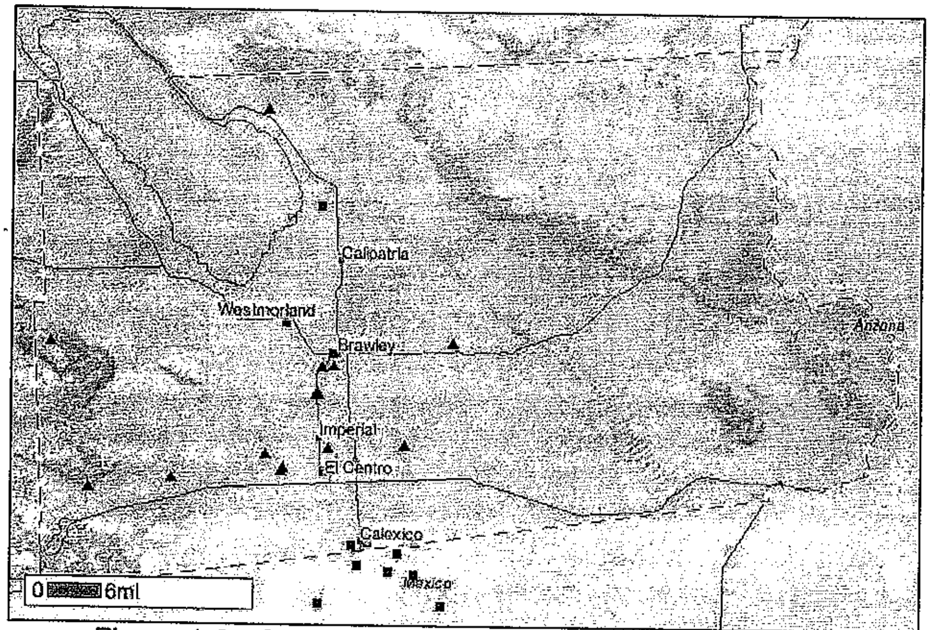


Figure 1-9: Stationary NOx Sources in Imperial County
*[Source: CARB Almanac, Imperial County Emissions]*

The possible source directions of the major PM2.5 components were investigated using Conditional Probability Function (CPF) Analysis (Kim and Hopke, 2004). CPF estimates the possible local source directions utilizing wind directions coupled with PM2.5 concentration and speciation data. The sources are likely to be located in the directions with high CPF values.

The Calexico-Ethel monitoring site experienced source impacts from primarily southern directions on exceedance days in the winter (Figure 1-10). These southern contributions indicate smoke and particulates from Mexicali.

The impact of smoke from Mexicali is further illustrated with the CPF analysis of potassium (K+) source contributions as illustrated in Figure 1-11. These figures also visually illustrate the transport of smoke from Mexicali into the City of Calexico.

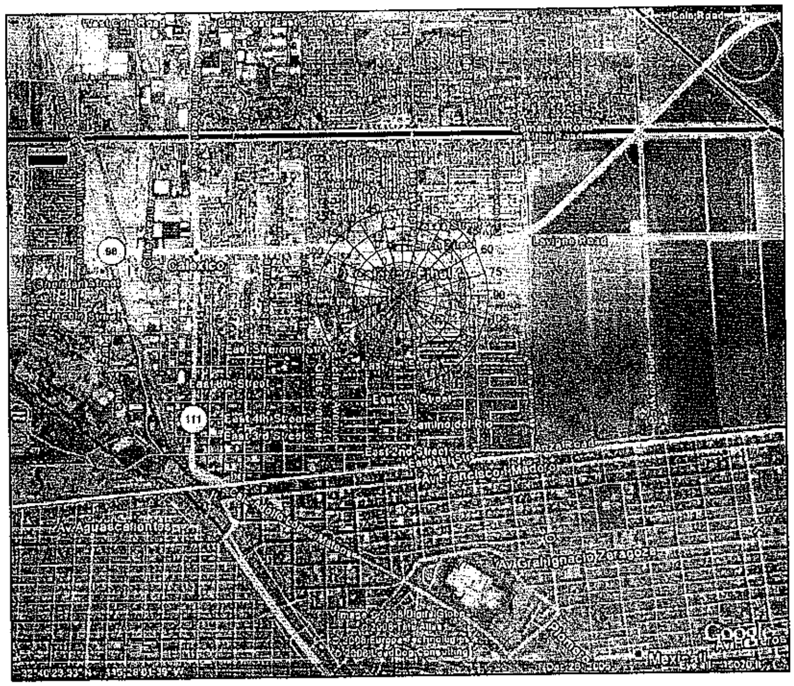


Figure 1-10: CPF Analysis of PM2.5 Concentration Source Contributions.

*[Map Source: maps.google.com; 12/26/2005]*

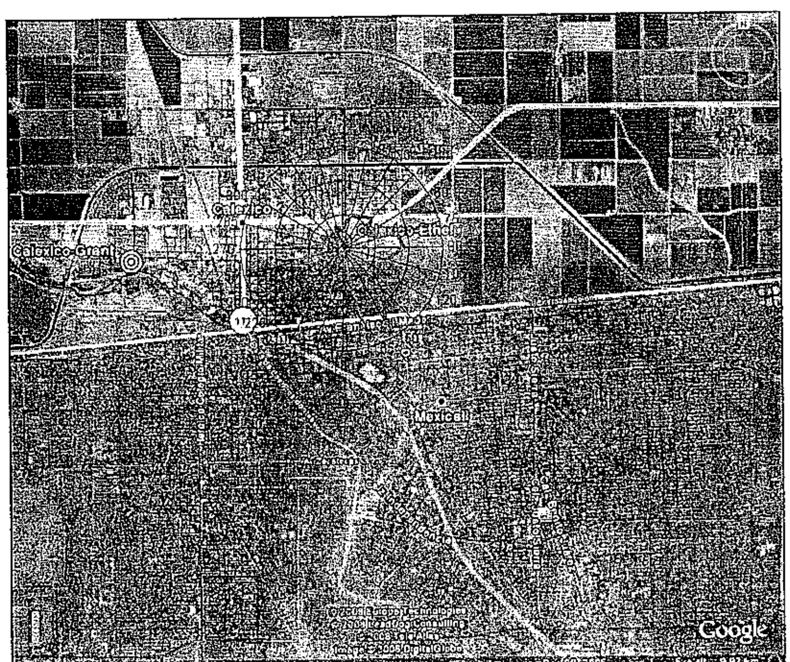


Figure 1-11: CPF Analysis of PM2.5 Potassium (K+) Concentration Source Contributions. *[Map Source: maps.google.com; 12/26/2005]*

**Summary**

In response to the two primary concerns of the U.S. EPA, ARB believes that the City of Calexico encompasses the population exposed to the high PM2.5 concentrations represented by the Calexico-Ethel site, and that the remainder of the county does not significantly contribute to PM2.5 exceedances at Calexico. ARB analysis continues to support that violations at Calexico are due to international transport from Mexico.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem in Imperial County is international transport, which affects only the local Calexico area.

Finally, the regional background of ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

An updated map, encompassing the complete population of the City of Calexico, and incorporating potential growth is shown in Figure 1-13.

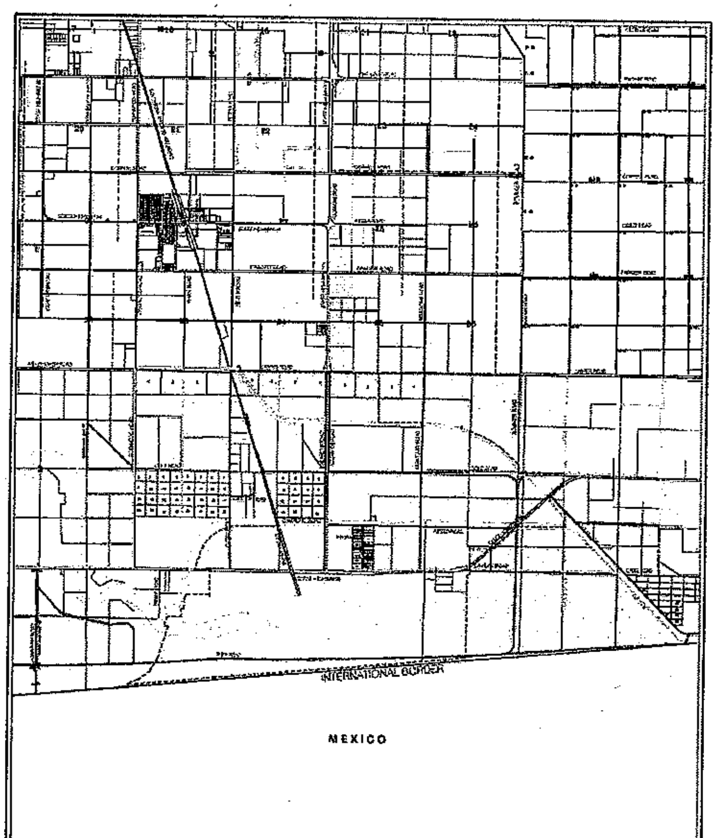


Figure 1-13: City of Calexico Sphere of Influence
[Source: Imperial County, CA]

## 2. Sacramento Air Quality Management District

The only violating monitors in the Sacramento area are located in the City of Sacramento; specifically, Sacramento-Del Paso, Sacramento-T Street, and Sacramento-Health Dept. Data from air quality monitors in surrounding counties, as shown in Figure 2-1, are well below the new standard (2007 Design Values are indicated in the colored circles) and far outside the zone of influence established by the Sacramento-Del Paso monitoring site. According to the CRPAQS study by Chow (Chow, et.al, 2006), a zone of influence is defined in which a concentration varies by 20%. Only the monitoring sites at Sacramento-T Street and Sacramento-Health Dept fall within this zone. The steep PM2.5 concentration gradients are illustrated in the figure below.

The U.S. EPA Response indicated that Placer County was in violation of the PM2.5 standard in 2006. The 2006 Design Value for the monitoring site in Placer County was, however, well below the standard at 31 ug/m3 (CARB iADAM website, 2008).

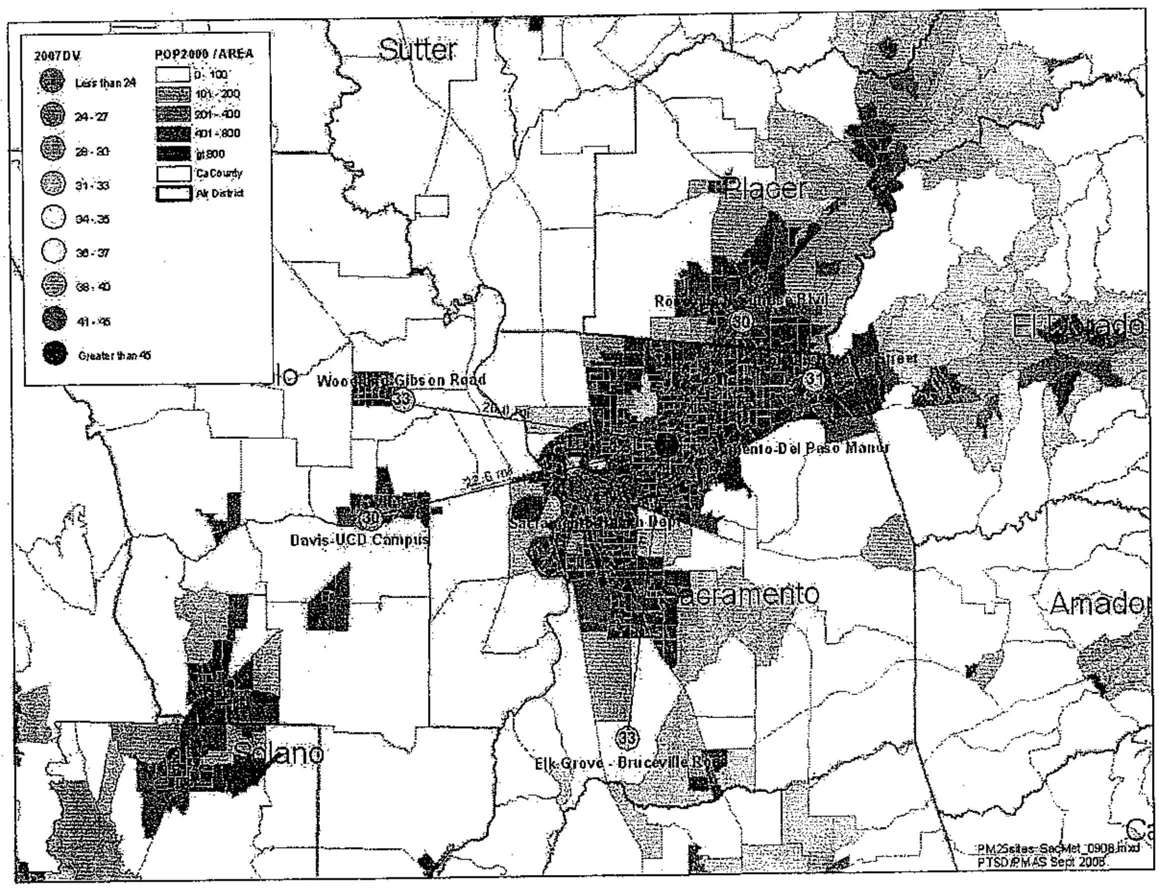


Figure 2-1: 2007 Design Values in Sacramento County Area

**Air Quality and Emissions**

As noted in the U.S. EPA Response and in Figure 2-2 below, during exceedance days in Sacramento, over 50% of the PM2.5 mass is organic carbon, primarily from residential wood burning. The seasonal pattern (Figure 2-3) shows the strong wintertime increases in organic carbon.

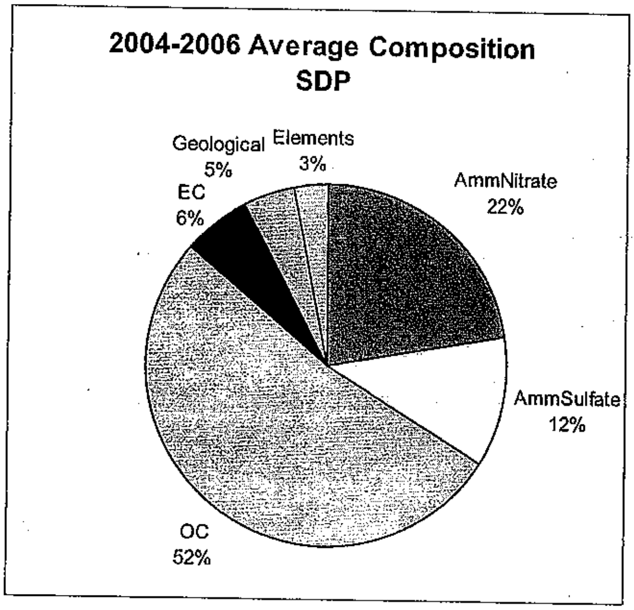


Figure 2-2: PM2.5 Composition, Sacramento-Del Paso, Sacramento County

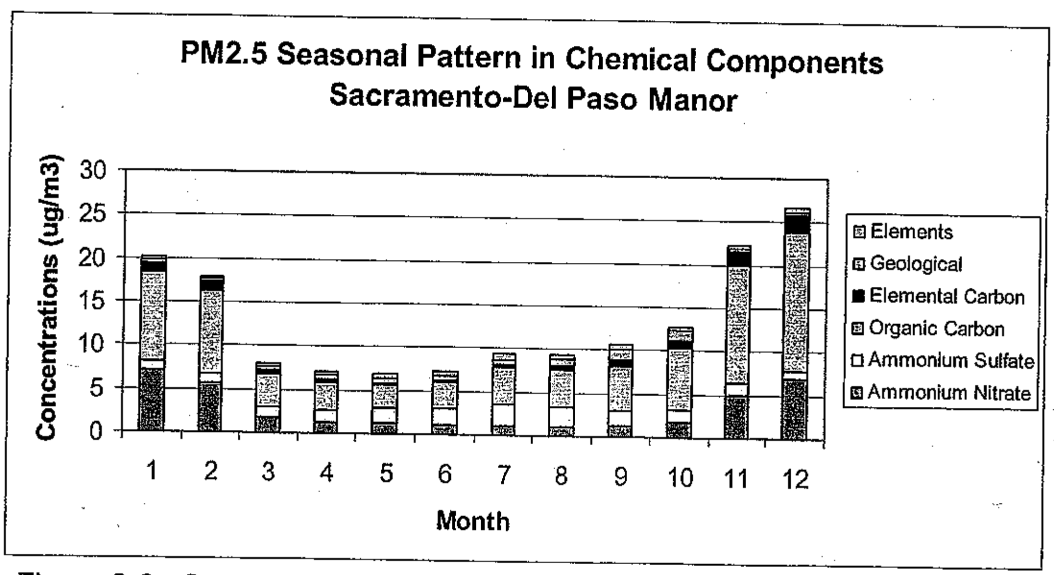


Figure 2-3: Seasonal Pattern of PM2.5 Composition, Sacramento-Del Paso

Chemical composition data is unavailable for other sites in the Sacramento region, but daily PM2.5 concentrations show the strong impact of winter PM2.5 emissions on the sites in the Sacramento urban area and the lesser impact at the more removed areas of Roseville and Woodland (Figure 2-4). These wintertime increases are due primarily to increased residential wood burning, as already noted in the area source emissions inventory in the U.S. EPA Response (Table 2, p.6). The Sacramento Metropolitan Air Quality Management District has already begun to address this issue. Mandatory wood burning controls were established in 2007. Their impact will be seen as early as 2008.

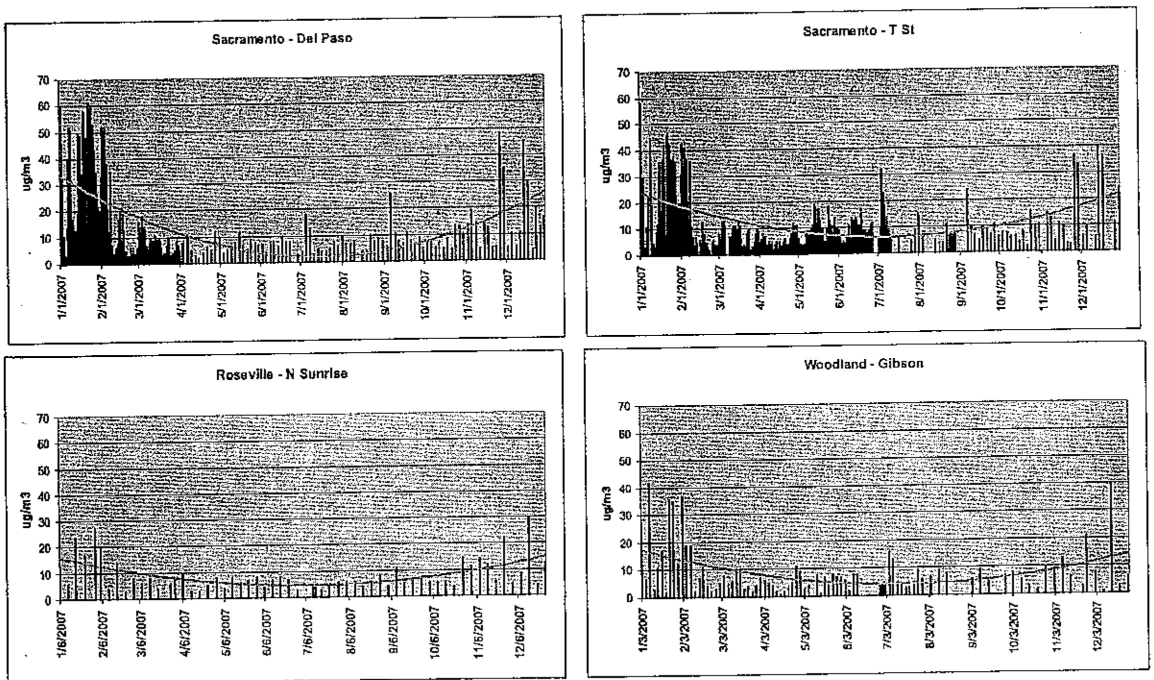


Figure 2-4: Seasonal Variation in PM2.5 at Four Sites in Sacramento Region

The use of county-wide emissions for areas such as Placer and El Dorado Counties, mountainous regions with large rural populations does not adequately reflect the reality of emissions within these areas. Although the majority of the population of El Dorado County resides in the western portion of the county, the population of the eastern portion, South Lake Tahoe and the surrounding mountainous areas, is over 25,000. The majority of the urban population of Placer County resides in the western part of the county, but almost a third reside in unincorporated areas.

Complete county emissions data was also used for Solano County, even though U.S. EPA split the county, overstating the contribution each adjacent portion may have on Sacramento County and the San Francisco Bay Area. Air quality monitoring data was split between the western and eastern parts of Solano County, the same care should be taken with the other factors contributing to the CES.

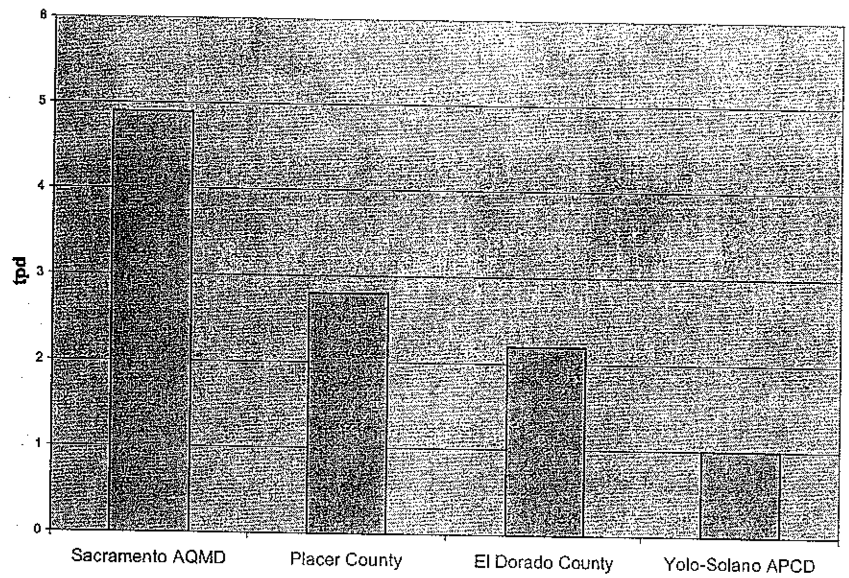


Figure 2-5: Wood smoke PM2.5 Emissions in the Sacramento Region

Recently, El Dorado County notified ARB that the residential wood combustion emissions in Table 2 of U.S. EPA's Response (p. 6) were incorrect and inaccurately indicated high residential burning emissions in El Dorado County. ARB staff worked to update these numbers, however, we were unable to separate the contribution from the Lake Tahoe Air Basin portion. Even including that portion, El Dorado County PM2.5 emissions for this category decreased significantly, from 5.3 to 2.2 tons/day. The chart above reflects the emissions and shows that PM2.5 emissions from Sacramento residential fuel combustion are significantly larger than any of the surrounding counties.

**Meteorology and Transport**

U.S. EPA notes that prevailing winds at Sacramento during exceedance days are from the northwest and southeast and during time periods with wind speeds of 4 miles per hour or less, concurring that high PM2.5 concentrations were dependent on calm-to-light winds. In other words, stagnant conditions were evident during the exceedance periods, an indication of local not transported pollutants.

ARB believes that exceedances were of a localized nature. Additional analysis (two exceedance days shown in Figure 2-6) shows little or no contribution from outlying areas. The trajectories (circled) indicate that air parcel movement was confined to the local area.

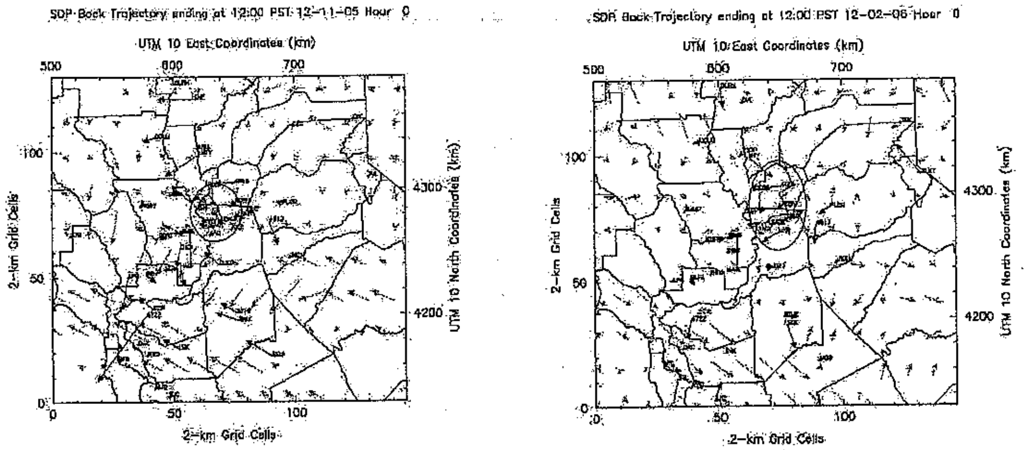


Figure 2-6: 2-D Wind Trajectories for Two Exceedance Days (12/11/05 and 12/2/06) at Sacramento-Del Paso

An examination of BAM data from Roseville and Sacramento-Del Paso are also indicative of the higher concentrations at Sacramento-Del Paso being due to local influence and not transport from Placer County (Figure 2-7).

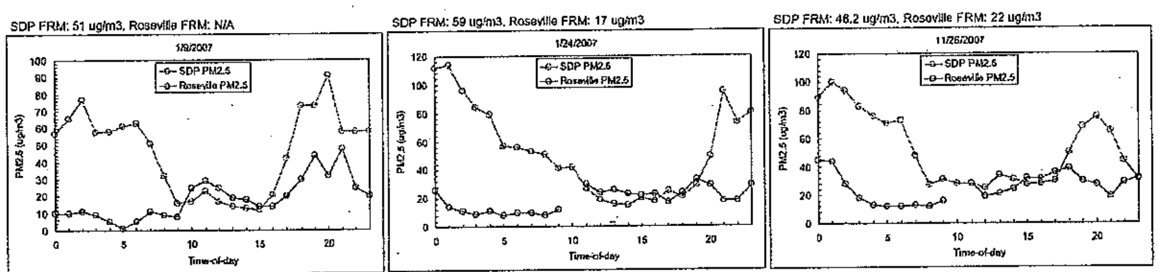


Figure 2-7: Diurnal PM2.5 Patterns at Sacramento-Del Paso and Roseville

The Roseville site remains fairly stable throughout each exceedance day. Some nighttime increases are noted on January 9, 2007, but are more likely the result of increased PM2.5 from local wood burning during stagnant conditions, which also resulted in local wood burning impacts at Sacramento-Del Paso. Local stagnant conditions for that day are further indicated by a HYSPLIT backward trajectory analysis (Figure 2-8).

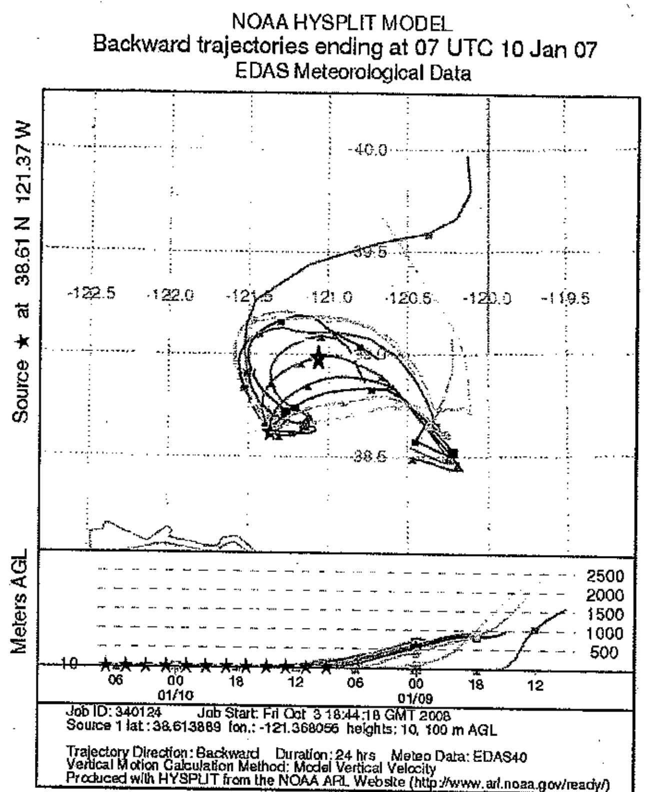


Figure 2-8: HYSPLIT Analysis of Wind Flow during Exceedance Day at Sacramento-Del Paso

## Contributing Emission Scores (CES)

One of U.S. EPA's goals in designating nonattainment areas in California was to achieve a degree of consistency with existing ozone and PM10 nonattainment areas. Application of this goal in California led to differences between the State's recommended nonattainment areas and U.S. EPA's proposed designations. When U.S. EPA originally designated the 8-hour ozone area for the Sacramento area consideration was given to the regional nature of the pollutant and emission sources as well as the presence of violating monitors throughout the region. The Sacramento Metropolitan ozone nonattainment area therefore includes all of Sacramento and Yolo Counties, and portions of Solano, Sutter, Placer, and El Dorado Counties. This was not the case for PM10. In that case, violating monitors occurred only within Sacramento County, which was, in and of itself, declared an appropriate boundary area. For PM2.5, the localized nature of organic carbon, which is the key contributor to wintertime violations, as well as the lack of violating monitors outside of the City of Sacramento, argue for a more focused nonattainment boundary similar to that of PM10.

U.S. EPA based part of its decision to include more counties in the Sacramento nonattainment area on the comparable population densities of surrounding counties to Sacramento County. The analysis for CES Factor 3 states that the populations associated with Sacramento clearly extend into Placer, El Dorado, Solano, and Yolo Counties. The surrounding counties' populations range from 4% to 34% of Sacramento County (Table 2-1). Surrounding counties' population densities range from 7% (El Dorado) to 35% (Solano) of Sacramento County.

Table 2-1: Population and Population Density in Sacramento and Surrounding Counties

| County/City | 2005 Population | % of Own County | % of Sacramento County | % of Five County Region | Pop Density |
|---|---|---|---|---|---|
| Sacramento | 1,363,423 | 100% | 100% | 55.6% | 1343 |
| Elk Grove | 136,318 | 10.0% | 10.0% | 5.6% | |
| Folsom | 70,835 | 5.2% | 5.2% | 2.9% | |
| Sacramento | 467,343 | 34.3% | 34.3% | 19.1% | |
| El Dorado | 176,319 | 100% | 12.9% | 7.2% | 98 |
| Placer | 316,868 | 100% | 23.2% | 12.9% | 210 |
| Roseville | 106,266 | 33.5% | 7.8% | 4.3% | |
| Solano | 410,786 | 100% | 30.1% | 16.8% | 471 |
| Yolo | 185,091 | 100% | 13.6% | 7.6% | 179 |
| Davis | 64,938 | 35.1% | 4.8% | 2.7% | |
| Woodland | 54,060 | 29.2% | 4.0% | 2.2% | |

[Source: www.csac.counties.org; www.cacities.org; www.census.gov]

Population growth, another factor (Factor 5) in determining CES, indicated substantial growth in the Sacramento area. As noted in Table 2-2, however, the majority of this growth, over half, is occurring in Sacramento County. Although growth rates in surrounding counties range from 4% to 28%, these rates are based on county populations significantly less than Sacramento (Figure 2-9).

Table 2-2: Population Growth in the Sacramento and Surrounding Counties

| County | 2000 Population | 2006 est. Population | County Growth | % Change of County | % of Regional Growth |
|---|---|---|---|---|---|
| Sacramento | 1,223,499 | 1,374,724 | 139,924 | 11.4% | 53.6% |
| El Dorado | 156,299 | 178,066 | 20,020 | 12.8% | 7.7% |
| Placer | 248,399 | 326,242 | 68,489 | 27.6% | 26.2% |
| Solano | 394,542 | 411,680 | 16,244 | 4.1% | 6.2% |
| Yolo | 168,660 | 188,085 | 16,431 | 9.7% | 6.3% |
| *COMBINED* | *2,191,399* | *2,478,797* | *261,088* | *11.9%* | *100.0%* |

[Source: www.census.gov]

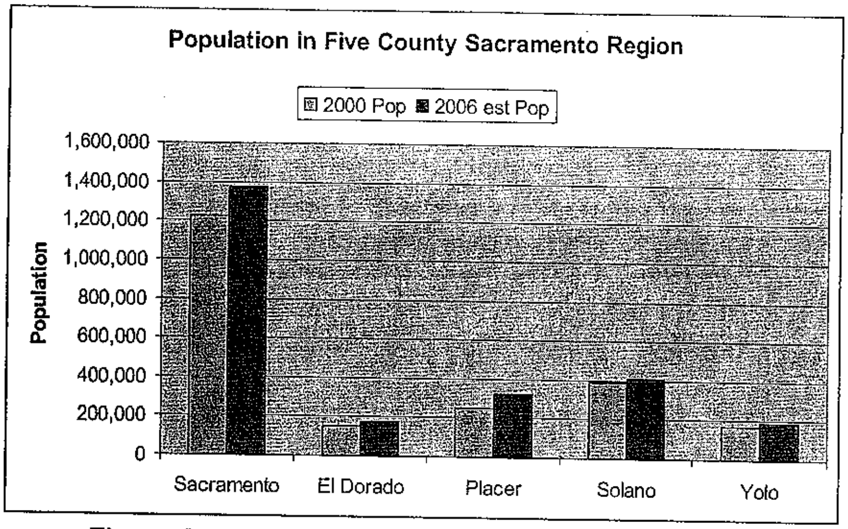


Figure 2-9: Population of the Sacramento Region
[Source: www.census.gov]

Although the CES is only one element in determining the nonattainment boundary areas, a high CES implies that a county has a high impact on the adjacent violating county. However, CES numbers are based on data for entire counties. The CES should be adjusted to reflect only those portions of a county to be included with an adjoining nonattainment area, such as Solano, El Dorado, and Placer Counties within the Sacramento nonattainment area.

The higher score of Solano was discounted, based on its contribution to the San Francisco Bay Area nonattainment area and the higher population in the western portion of the county. The high scores for Placer and El Dorado were based, partially, on analysis done for the entire counties. As noted in U.S. EPA Technical Document (Rizzo and Hunt, 2008), the CES methodology uses county-based emissions inventories which may be inaccurate in counties with large rural populations or with mountainous terrain, both of which occur in El Dorado and Placer. Although U.S. EPA took some of this into account in recommending only a part of each county for inclusion in the nonattainment area, it did not take into account the fact that the majority of PM2.5 emission are from residential wood burning. These emissions were recently found to be inaccurate (pages 17 and 18 of this report) and a significant portion may be occurring in the Lake Tahoe Air Basin segment of these counties.

Use of population and population growth as factor in U.S. EPA's decision-making was not consistent throughout the country. Warren County, New Jersey, is an example of a county not included with an adjacent violating area. According to U.S. EPA, "Warren County [New Jersey] ranks low in terms of population and in population density in comparison to counties located near the violating monitor in Northampton County, Pennsylvania. In comparison to the two counties that have been recommend as nonattainment for the Allentown, PA-NJ area, *Warren County's population and population density is below 50% that of Lehigh and Northampton.* (U.S. EPA Response to New Jersey, 2008)" Warren County's population density is, in fact, 32% of Lehigh

County and 40% of Northampton County. Although, the Sacramento County population is larger than the populations for counties around Warren County, NJ; Sacramento's population density is very similar. Both total populations and population densities for all surrounding counties are below those of Sacramento County and far below the U.S. EPA stated limit above of 50%.

In an additional example, Hamblen County, part of the Knoxville-Sevierville-LaFollette, TN CBSA, has a population density 44% of neighboring (and violating) Knox County. Hamblen County was designated in attainment (U.S. EPA Response to Tennessee, 2008). There are many other examples of counties with higher population densities than those adjoining Sacramento, within a MSA, but not designated nonattainment.

EPA has placed a high importance on the Contributing Emissions Scores (CES) in designating nonattainment areas. While several counties in California have a relatively low CES and no violating monitor, U.S. EPA has still proposed a nonattainment designation in tandem with neighboring violating counties. In several other areas throughout the country, however, counties with similar, or higher, CES are not wed to their adjacent nonattainment counties (Table 2-3). California requests similar flexibility as provided to other areas of the country.

Table 2-3: Sample of Counties with CES scores at or above 16 with Adjacent PM2.5 Nonattainment Areas

| **Attaining County, State** | **CES score** | **Adjacent Violating Area** |
|---|---|---|
| Clinton County IA | 52 | Davenport-Moline-Rock Island, IA-IL 2006 CBSA |
| Cedar County IA | 17 | |
| Louisa County IA | 36 | Muscatine, IA 2006 CBSA |
| Johnson County IA | 24 | |
| Greenup County KY | 24 | Huntington-Ashland Area 2006 CBSA |
| Dickson County TN | 19 | Clarksville-Hopkinsville, KY-TN 2006 CBSA |
| Robertson County TN | 17 | |
| Posey County IN | 19 | Evansville Metropolitan Statistical Area |
| Pickaway County OH | 19 | Columbus Metropolitan Statistical Area |
| Ross County OH | 18 | |
| Adams County OH | 18 | |
| Jefferson County TN | 17 | Knoxville-Sevierville-LaFollette, NA area, 8-hour ozone |

**Summary**

In response to the two primary concerns of the U.S. EPA, ARB believes that Sacramento County encompasses the population exposed to the high PM2.5 concentrations represented by the Sacramento-Del Paso, Sacramento-Health Dept., and Sacramento-T St. sites, and that the remainder of the region does not significantly contribute to PM2.5 exceedances in Sacramento County.

Sacramento County, which encompasses the majority of the population in the region, is the only area that violates the new PM2.5 standard. ARB analysis continues to support that violations in Sacramento are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

In other areas throughout the country, counties with CES scores comparable to those counties surrounding Sacramento, were not included as part of adjacent nonattainment areas. Following the same rationale, the non-violating Counties of Yolo, Solano, El Dorado, and Placer should not be part of the Sacramento PM2.5 nonattainment area.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for the County of Sacramento.

## 3. City of Chico, Butte County Air Quality Management District

The only violating monitor in Butte County is located in the City of Chico, which has a 2007 Design Value (DV) of 55 ug/m3. A continuous beta attenuation monitor (BAM) located in the City of Gridley, a community to the south of Chico, shows a 2007 DV of 33 ug/m3 (Figure 3-1). Chico, the largest urban area in Butte County, has a population three-to-five times other areas in the county (Table 3-1). Based on the localized nature of the primary emission contribution to winter PM2.5 (Figures 3-2 through 3-4), ARB considers the urban area of Chico an appropriate nonattainment boundary for PM2.5.

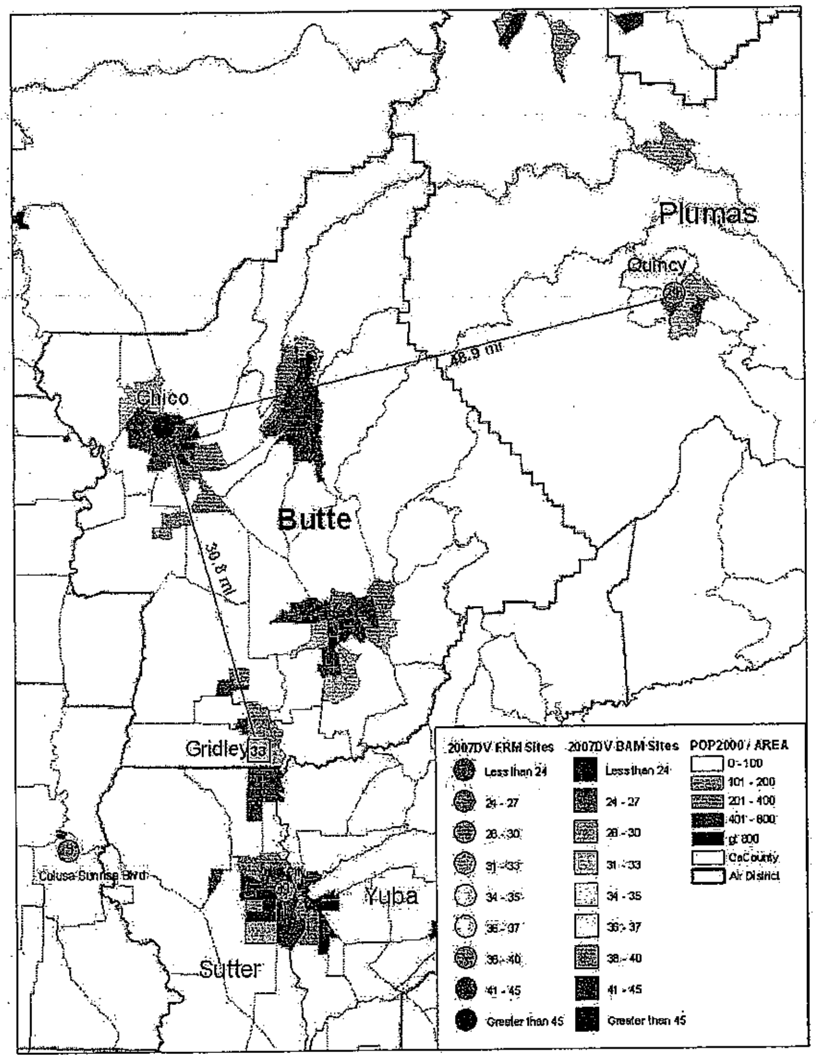


Figure 3-1: 2007 Design Values in Butte County

Table 3-1: Demographic Information, Butte County

| County/City | Population | Population Density (pop./mi$^2$) |
|---|---|---|
| Butte County | 219,101 | 132 |
| Biggs | 1,809 | 3471 |
| Chico | 84,396 | 2547 |
| Gridley | 6,167 | 3769 |
| Oroville | 14,443 | 1103 |
| Paradise | 26,725 | 1446 |

*[Source: U.S. Census, www.census.gov; California State Association of Counties, www.csac.counties.org; League of California Cities,www.cacities.org]*

As shown in Figure 3-2, 75% of PM2.5 on exceedance days in Chico is composed of organic carbon, primarily from residential wood combustion. The seasonal variation of PM2.5 chemical composition is seen in Figure 3-3. Although ammonium nitrate also shows a winter increase, by itself it would not be enough to cause Chico to exceed the new federal standard. Exceedances are due primarily to increased winter-time residential wood burning, a more localized pollutant. The low wind speeds exhibited during times of PM2.5 exceedances, as noted in the pollution wind rose on page 16 of the U.S. EPA Response, only reinforces that exceedances result from a localized source such as wood burning. Residential wood combustion, particularly during times of low winds or stagnant conditions, is the primary cause of Chico's PM2.5 exceedances.

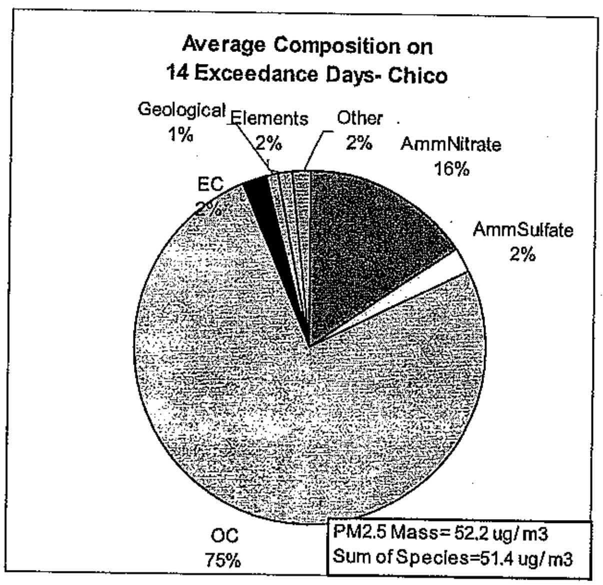


Figure 3-2: PM2.5 Composition, City of Chico, Butte County

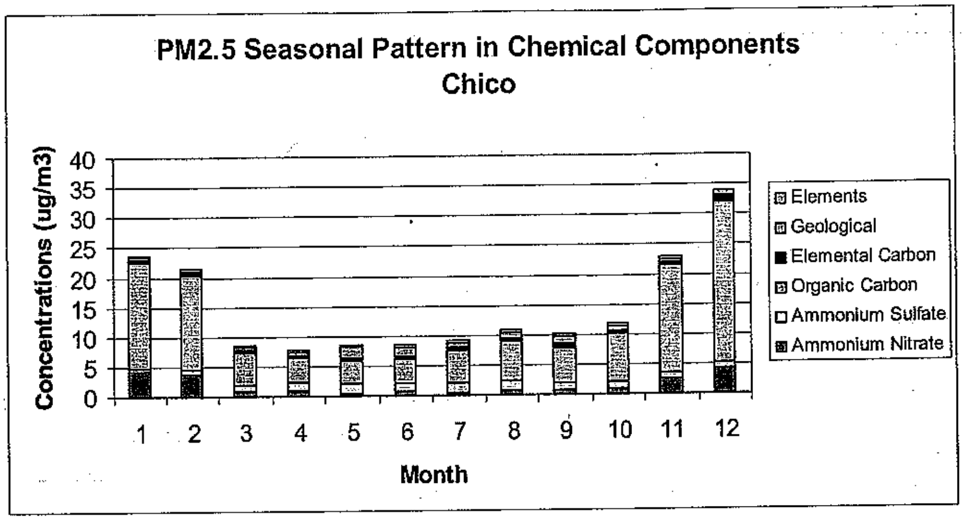


Figure 3-3: Seasonal Pattern of PM2.5 Composition, City of Chico, Butte County

A diurnal analysis of concentrations at Chico and Gridley, during Chico exceedance days, highlights the localized nature of the PM2.5 pollution episodes (Figure 3-4). The nighttime increases at Chico, the result of residential wood burning, are not reflected at the monitoring site at Gridley. As previously noted, the majority of exceedance days occur during periods of stagnant or low wind, keeping pollutants close to the emission source.

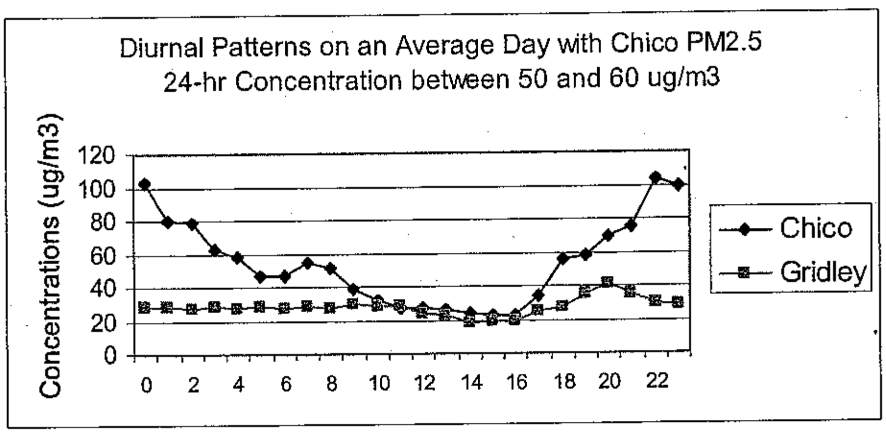


Figure 3-4: Diurnal PM2.5 Patterns at Chico and Gridley

**Summary**

In response to the two primary concerns of the U.S. EPA, ARB believes that the City of Chico encompasses the population exposed to the high PM2.5 concentrations represented by the Chico-Manzanita site, and that the remainder of the county does not significantly contribute to PM2.5 exceedances in the City of Chico.

The City of Chico, which encompasses the majority of the urban population in the county, is the only site that violates the new PM2.5 standard. ARB analysis continues to support that violations in Chico are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem is wood smoke, which affects the localized Chico urban core.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for the City of Chico. Similar to our recommendation for the City of Calexico, we believe that the City of Chico's sphere of influence may be an appropriate boundary. The General Plan Diagram of the City of Chico, outlining the sphere of influence (gold boundary), is shown in Figure 3-5.

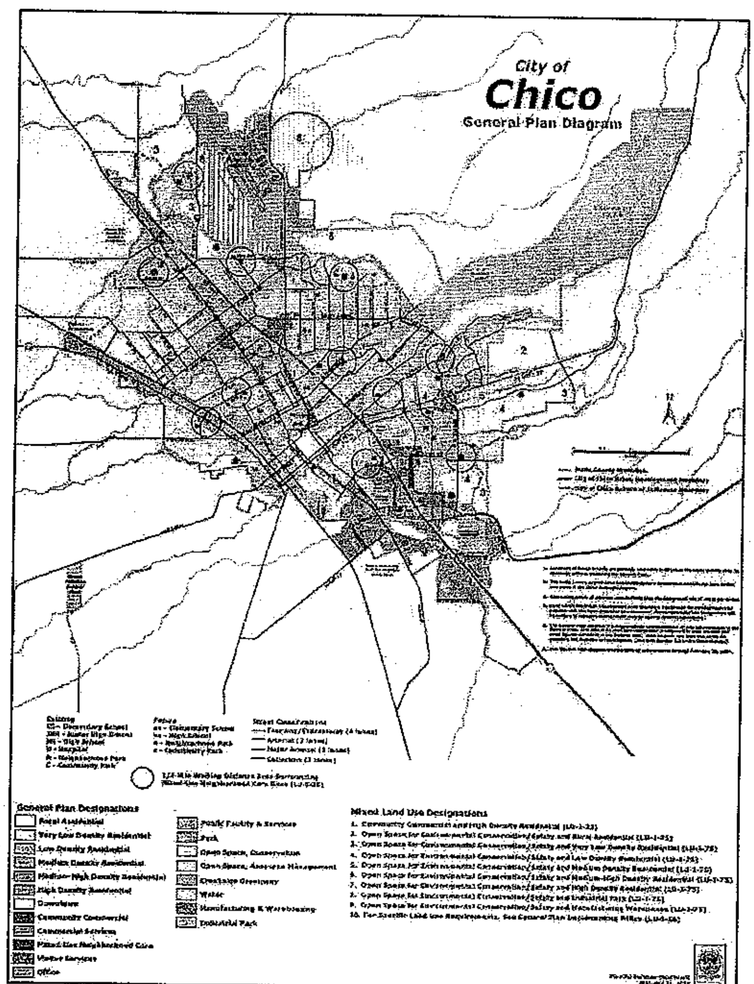


Figure 3-5. City of Chico, Sphere of Influence
*[Source: City of Chico, www.chico.ca.us]*

4. Combined Cities of Yuba City/Marysville, Feather River Air Quality Management District

The only violating monitor in the Feather River Air Quality Management District (Feather River) is located in Yuba City, which has a 2007 Design Value of 39 ug/m3 (Figure 4-1). Yuba City, the largest urban area in Sutter County, is home to over 65% of the County's population; 18% of Yuba County's residents live in Marysville, located in Yuba County but sharing a border with Yuba City. Combined, the two cities account for 44% of the population of the two counties. Based on the localized nature of the primary emission contribution to winter PM2.5 (Figures 4-2 through 4-4), ARB considers the combined urban areas of Yuba City/Marysville an appropriate nonattainment boundary for PM2.5.

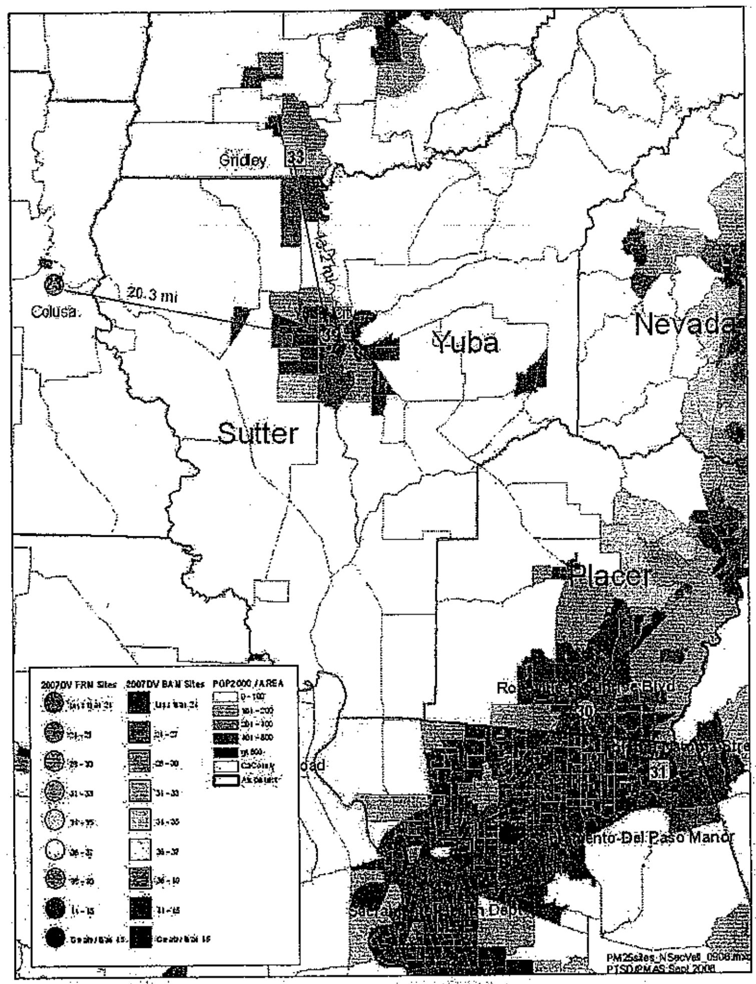


Figure 4-1: 2007 Design Values in Sutter and Yuba Counties

As shown in Figure 4-2, almost 55% of PM2.5 on exceedance days in Yuba City is composed of total carbon (tcm), primarily from residential wood combustion. A seasonal variation of PM2.5 chemical composition is not available for this site, but a look at the mass concentrations throughout the 2007 clearly show the higher concentrations experienced during the winter (Figure 4-3). Exceedances are due primarily to increased winter-time residential wood burning and ammonium nitrate. The low wind speeds exhibited during times of PM2.5 exceedances, as noted in the pollution wind rose on page 16 of the U.S. EPA Response, only reinforces the exceedances as resulting from a localized source such as residential wood burning.

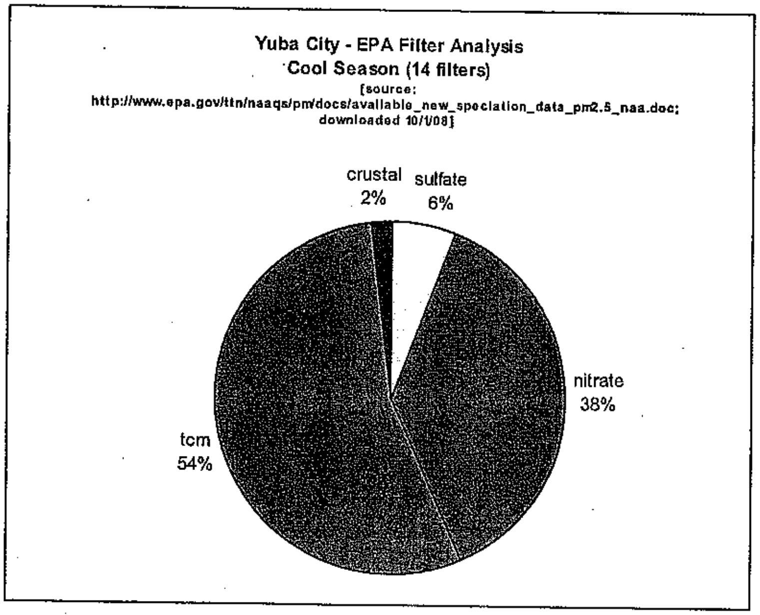


Figure 4-2: PM2.5 Composition, Yuba City, Sutter County

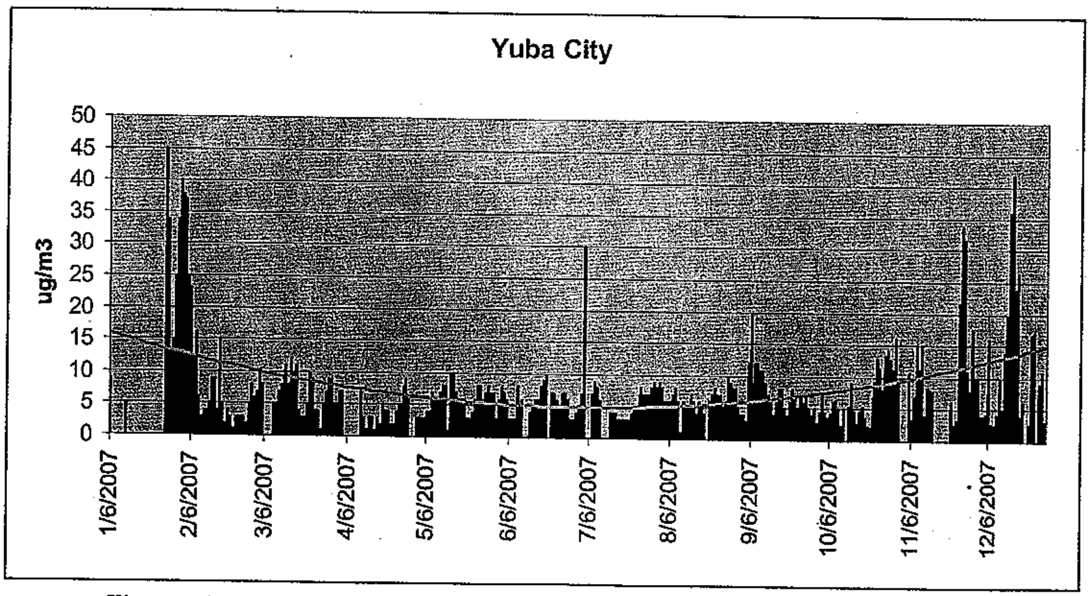


Figure 4-3: Seasonal Pattern of PM2.5, Yuba City, Sutter County

The localized nature of the PM2.5 pollution problem in Yuba City can also seen in this diurnal analysis (Figure 4-4) of concentrations at Yuba City for days that the standard was exceeded at Yuba City. The high nighttime concentrations at Yuba City reflect the diurnal pattern of residential wood burning, separate from the patterns exhibited by commuter traffic, which would show a decrease after peak commuter hours. As previously noted, the majority of exceedance days occur during periods of stagnant or low wind, keeping pollutants close to the emission source, in this case, Yuba City and Marysville.

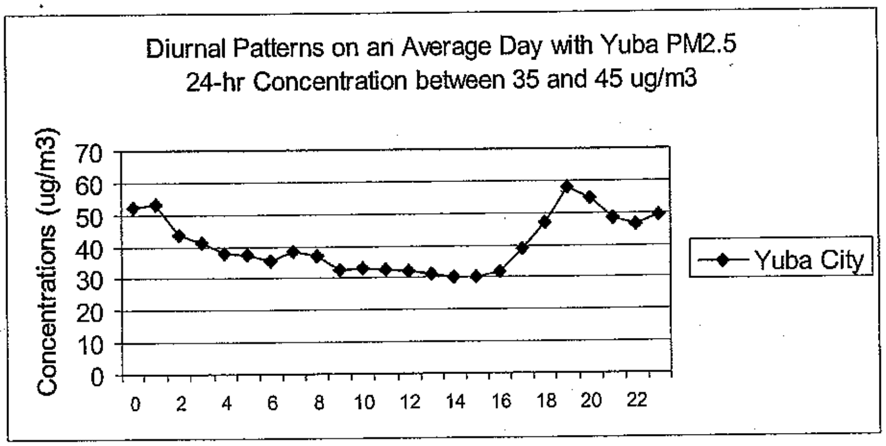


Figure 4-4: Diurnal PM2.5 Patterns at Yuba City

**Summary**

In response to the two primary concerns of the U.S. EPA, ARB believes that the urban area of Yuba City/Marysville encompasses the population exposed to the high PM2.5 concentrations represented by the Yuba City site, and that the remainder of the Sutter and Yuba Counties do not contribute significantly to PM2.5 exceedances in the combined Yuba City/Marysville urban area.

The combined Cities of Yuba City/Marysville, which encompass the majority of the urban population in the Counties of Sutter and Yuba, is the only site that violates the new PM2.5 standard. ARB analysis continues to support that violations in Yuba City/Marysville are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem is wood smoke, which affects the localized Yuba City/Marysville urban core.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for Yuba City/Marysville. Similar to our recommendation for the City of Calexico, we believe that the combined Yuba City/Marysville sphere of influence may be an appropriate boundary. We are working with local agencies to obtain maps to document this area.

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- Area Designations for 2006 24-Hour Fine Particulate (PM2.5) Standards. www.epa.gov/pmdesignations/2006standards/state.htm
  - Region 2: www.epa.gov/pmdesignations/2006standards/rec/region2.htm
    - New Jersey: .../rec/letters/02_NJ_EPAMOD.pdf
  - Region 4: www.epa.gov/pmdesignations/2006standards/rec/region4.htm
    - Tennessee: .../rec/letters/04_TN_EPAMOD.pdf

# Attachment H

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

THE ADMINISTRATOR

JAN 1 4 2009

Mr. Paul R. Cort
Earthjustice
426 17th Street, 5th Floor
Oakland, California 94612

Dear Mr. Cort:

This letter is in response to your July 15, 2008, Petition for Reconsideration and request for a stay on behalf of the Natural Resources Defense Council (NRDC) and Sierra Club (SC) related to the U.S. Environmental Protection Agency's (EPA's) final rule titled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)," which was published in the *Federal Register* on May 16, 2008, and effective on July 15, 2008. The specific provisions for which you requested reconsideration include (1) EPA's transition schedule and requirements for Prevention of Significant Deterioration (PSD) programs in State Implementation Plan (SIP)-approved states; (2) EPA's grandfathering provisions concerning use of the Particulate Matter Less Than 10 Micrometers ($PM_{10}$) surrogate policy contained in the regulations governing the federal PSD permitting program; (3) EPA's transition period for condensable particulate matter (CPM) emissions; and (4) EPA's preferred interpollutant trading ratios under the nonattainment NSR program. Due to the limited resources of the Agency, and for the reasons stated previously in support of the rule and as explained further below, EPA denies this petition for reconsideration and request for a stay.

The NRDC and SC petition requires EPA to consider the staff time and other resources that would be expended to reconsider this final rule in light of the many responsibilities of the Agency and the limited resources available to the Agency. EPA's conclusion is that the resources that would be required to complete the reconsideration process if the Agency granted your petition are more appropriately used on other matters.

Having considered your arguments with respect to each of the provisions for which you request reconsideration, EPA concludes that they do not demonstrate a need for reconsideration, for the reasons stated previously in support of the rule and as explained further below.

**Transition Period for PSD Programs in SIP-approved States**

In its petition, NRDC and SC claim that in our final rule we included new requirements governing the way in which states with SIP-approved PSD programs will come into compliance with the new PSD rules for $PM_{2.5}$ that are unlawful and arbitrary. The new PSD rules require states to submit revised programs within three years from the publication of amended requirements in the *Federal Register* in accordance with 40 CFR 51.166(a)(6)(i). During the interim period prior to EPA approval of the revised rules, states may continue to implement the $PM_{10}$ surrogate policy as a means of satisfying the new requirements for $PM_{2.5}$.

Consistent with past practice, we believe that it is reasonable to allow states up to three years to revise and submit SIP revisions containing the new requirements for the $PM_{2.5}$ PSD program, while allowing states the opportunity to rely on the $PM_{10}$ surrogate policy in the interim if it is necessary to do so. Reconsideration is not warranted because the public had notice of the potential that EPA would give states this amount of time to submit SIP revisions. The three-year period within which states must adopt the new $PM_{2.5}$ requirements into SIP-approved programs is provided by the pre-existing PSD rules to allow states to revise their own regulations to reflect newly amended requirements. As stated in the May 16, 2008, preamble, "This rule follows our established approach for determining when States must adopt and submit revised SIPs following changes to the NSR regulations, but does not revise otherwise applicable SIP submittal deadlines." 73 FR 28321, 28341. The May 16, 2008, rule requires revision to the initial "infrastructure" SIPs that EPA required states to submit within three years of the promulgation of the $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). Thus, the deadline in section 110(a)(1) of the Act does not apply to the SIP revisions submitted in response to the May 16, 2008, rule. The Act does not specifically address the timeframe by which states must submit SIP revisions. Nevertheless, we looked to section 110(a)(1) of the Act to guide our development of the previous rule that allows up to a 3-year SIP development period for states to incorporate new or amended PSD program requirements.

Petitioners' recommendation that upon reconsideration EPA should impose new $PM_{2.5}$ requirements under the existing federal PSD program (40 CFR 52.21) for all states until adequate SIP revisions have been approved fails to account for the time required to legally act to disapprove all affected state programs and undertake the necessary rulemaking to begin implementation of federal PSD for $PM_{2.5}$. Many states have already indicated that they have the general authority to regulate $PM_{2.5}$ under their existing SIPs even though specific regulatory changes are needed to fully implement the program in accordance with EPA's newly amended rules.

Use of the $PM_{10}$ surrogate policy does not "waive" or "exempt" sources from complying with the statutory requirements; states with existing authority to implement the new $PM_{2.5}$ program will not need to continue implementing the $PM_{10}$ surrogate policy. The surrogate policy remains in place to provide states lacking clear authority in state law to directly regulate $PM_{2.5}$ with the ability to issue permits satisfying the $PM_{2.5}$ requirements without unnecessary delay. As we explained in the May 16, 2008, preamble, "$PM_{10}$ will act as an adequate surrogate for $PM_{2.5}$ in most respects, because all new major sources and major modification that would trigger PSD requirements for $PM_{2.5}$ would also trigger $PM_{10}$ requirements because $PM_{2.5}$ is a subset of $PM_{10}$." 73 FR 28321, 28341. Nevertheless, we disagree with your contention that "The new transition scheme purports to allow source [sic] to be constructed or expanded even if they result in long-term contributions to violations of the $PM_{2.5}$ NAAQS."

We emphasize that the continued use of the $PM_{10}$ surrogate policy is not mandatory, and case-by-case evaluation of the use of $PM_{10}$ in individual permits is allowed to determine its adequacy of as a surrogate for $PM_{2.5}$. If, under a particular permitting situation, it is known that a source's emissions would cause or contribute to a violation of the $PM_{2.5}$ NAAQS, we do not believe that it is acceptable to apply the $PM_{10}$ surrogate policy in the face of such predicted violation. Accordingly, each permit that relies on the $PM_{10}$ surrogate policy to satisfy the new $PM_{2.5}$ requirements is subject to review as to the adequacy of such presumption.

**Continuation of $PM_{10}$ Surrogate Policy for Certain Pending Permit Applications Under the Federal PSD Program ("Grandfathering Provision")**

NRDC and SC contend that our policy of allowing sources with complete applications submitted prior to the July 15, 2008, effective date of the federal PSD regulations at 40 CFR 52.21 to continue relying upon the $PM_{10}$ surrogate policy is unlawful and arbitrary. Your contention was in part that we failed to present this grandfathering provision and accompanying rationale to the public for comment, and also that the Clean Air Act (Act) provides no authority for EPA to ground the grandfathering provision on the date of a source's permit application. You stated that upon reconsideration we "must require that $PM_{2.5}$ be addressed in all permits for sources that did not commence construction before the effective date of the $PM_{2.5}$ NAAQS." Your approach would require that we retroactively review all permits issued since the effective date of the $PM_{2.5}$ NAAQS, i.e., either July 18, 1997 – the date of the original $PM_{2.5}$ NAAQS, or October 17, 2006 – the date we revised the original $PM_{2.5}$ NAAQS. We do not consider this the best use of limited agency resources.

With regard to the petition's premise that the Act does not authorize EPA to grandfather sources on the basis of a complete application, we disagree. Section 168(b) of the Act provides for certain grandfathering based on a commence construction date, but says nothing – either explicitly or implicitly – about whether other grandfathering may occur or what criteria should be applied in allowing for additional grandfathering by regulation. Moreover, we believe that a decision to re-evaluate sources already grandfathered would unnecessarily disrupt state permitting programs by requiring such permits to be re-evaluated for impacts on the $PM_{2.5}$ NAAQS.

Even if we were to consider eliminating the new grandfathering provision that became effective on July 15, 2008, it could be of little consequence because we have determined that only nine sources actually submitted applications relying on the $PM_{10}$ surrogate policy prior to July 15, 2008, such that they fall within the grandfather provision. Of these, interested persons submitted comments on the use of the surrogate policy with respect to only six of these applications. Moreover, we believe that control technologies qualifying as Best Available Control Technology (BACT) for $PM_{10}$ are likely in many cases to serve as BACT for $PM_{2.5}$ as well.

Finally, as we noted above, the use of the surrogate policy for the sources grandfathered under the federal PSD program does not "waive" or "exempt" sources from complying with statutory requirements; rather, it presumes that assessing control technologies and modeling air quality impacts for $PM_{10}$ is an effective means of fulfilling those statutory requirements for $PM_{2.5}$ as well as for $PM_{10}$ during the transition period being allowed.

**Condensable Particulate Matter Emissions**

NRDC and SC claim that our decision in the final NSR rule to allow states to exclude CPM from NSR applicability determinations and emissions control requirements until January 1, 2011, is unlawful and arbitrary. You further note that we did not propose such exclusion for public review and comment.

The final provisions on condensable particulate matter emissions were not adopted without notice, as you have claimed. As discussed in the notice of proposed rulemaking, the states and EPA have not consistently applied the NSR program to CPM. The final rule merely deferred the effective date of the proposed action and preserved the status quo in the interim – requiring continued enforcement of those SIPs and permits that clearly address CPM. Our decision in the final rules to allow states that have not previously addressed CPM to continue to exclude CPM during a transition period is the direct response to comments we received questioning whether available test methods and modeling techniques were reliable enough to support a requirement that all states immediately begin addressing CPM as originally proposed. See 73 FR at 28,335 (discussing comments and EPA's response).

The transition period is temporary, and the total time allowed could be shortened in conjunction with a faster-than-anticipated rulemaking for new or revised CPM test methods. Also, as discussed above, states with SIP provisions requiring CPM to be addressed are not allowed to exclude CPM, and other states at their discretion have opted to include CPM in their permit processes. In addition, some sources have elected to include CPM in their estimates of potential emissions in order to avoid possible delays (resulting from adverse public comment) in the issuance of needed permits.

Even where sources are not being required to address CPM, control technologies being selected as BACT for $PM_{10}$ and $PM_{2.5}$ are capable of controlling CPM.

**Interpollutant Trading Ratios**

Finally, NRDC and SC claim that our decision to include preferred interpollutant trading ratios to facilitate the interpollutant trading of emissions offsets under the NSR program is unlawful and arbitrary. NRDC and SC assert that such ratios were developed and finalized without public input. Moreover, you claim that the Act does not permit interpollutant offset trading.

We believe the Act contains the necessary authority for us to regulate precursor emissions, including allowing offset trading of such precursors. As defined under section 302(g) of the Act, the term "air pollutant" "includes any precursors to the formation of any air pollutant, to the extent that the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used."

The rule does not require use of the preferred ratios, and public notice and comment is built into the process through which the interpollutant trading program is incorporated into the state NSR program. That is, each SIP revision containing an interpollutant trading program, including the preferred offset ratios or any other ratios independently adopted by the state, must be subjected to public notice and comment as part of the EPA approval process for the SIP (in addition to the public process required as part of the state's adoption of such provisions in their own rules.) Under 40 CFR part 51 appendix S, the interim authority for issuance of major permits in nonattainment areas by states, states may allow $PM_{2.5}$ precursor offsets "if such offsets comply with an interprecursor trading hierarchy and ratio approved by the Administrator." See new section IV.G.5 of appendix S. Moreover, each permit which relies on the interpollutant trading program to allow precursor emissions to offset new $PM_{2.5}$ emissions must undergo public review prior to approval and issuance.

**Request for Stay of Implementation**

NRDC and SC also request that EPA stay implementation of the final rule pending reconsideration or the rule. Because EPA is denying the petition for reconsideration in its entirety, a stay pending reconsideration is unnecessary.

We appreciate your comments and interest in this important matter.

Sincerely,

Stephen L. Johnson

cc: Mr. David S. Baron, Earthjustice
Mr. Timothy J. Ballo, Earthjustice