TESTIMONY

of

J. PHYLLIS FOX, Ph.D.

on

Air Quality Impacts

Relating to the

La Paz Generating Facility

Submitted on behalf of

Arizona Unions For Reliable Energy

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I have reviewed the following materials submitted by Allegheny Energy Supply, LLC ("applicant"): (a) Application for a Certificate of Environmental Compatibility for the La Paz Generating Facility, submitted to the Arizona Power Plant and Transmission Line Siting Committee (July 3, 2001; and (b) Application for a Class I Permit for the La Paz Generating Facility, submitted to the Arizona Department of Environmental Quality (October 2, 2001). The following is my testimony relating to the information provided therein.

BEST AVAILABLE CONTROL TECHNOLOGY

I. BEST AVAILABLE CONTROL TECHNOLOGY ("BACT") NOT REQUIRED FOR TURBINES

Under the federal Clean Air Act, a new major source such as the La Paz Project must apply best available control technology ("BACT"). The Siting Application claims that BACT for the turbines is 2.5 parts per million volume basis ("ppmv") for nitrogen oxides ("NOx"), 10 ppmvd for ammonia slip ("NH_3"), 5 ppmv for carbon monoxide ("CO"), and 2.9 ppmv for volatile organic compounds ("VOCs"). However, a review of the supporting information indicates that the proposed emission limits are not BACT.

BACT means (AAC R18-2-101(19)):

> an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director... to be achievable for such source or modification.

BACT is normally selected using the "top-down" process as outlined in EPA's NSR Manual. (NSR Manual,[1] Chapter B.) The New Source Review ("NSR") Manual and the top down procedure have been accepted by EPA's Environmental Appeals Board ("EAB") "as the most current statement of the

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[1] U.S. EPA, New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

Agency's thinking on BACT issues" and are routinely used to decide cases involving matters of federal law.

The top-down BACT process consists of five steps that are discussed in detail in Section B of the NSR Manual and articulated in the Siting Application. (App., pp. B-1-5/6.) These steps are (NSR Manual, Table B-1):

1. Identify all control technologies (including lowest achievable emission rate or LAER)
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate the most effective control and document results
5. Select BACT

In brief, the top-down process requires *all* emission limits to be ranked in descending order. The applicant must first examine the most stringent - or "top" - limit. That limit is established as BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent limit is not "achievable." (NSR Manual, p. B.2.)

The top-down BACT analyses performed by the applicant deviate substantially from this federal guidance because they failed to identify, evaluate, and select the lowest emission limits, as discussed below. As a result, the applicant has not selected BACT for this project.

I.A Averaging Times Not Specified

BACT is an emission limit under both the Arizona and federal definitions of BACT. An emission limit must be accompanied by an averaging time to be federally enforceable. (NSR Manual, p. B.56.) Thus, proper BACT limits are always accompanied by an averaging time, e.g., 2.5 ppmv averaged over 1 hour. None of the proposed BACT limits included in either the Siting or the Class I Permit Applications is accompanied by an averaging time.

I.B BACT For NOx From The Gas Turbines Not Required

The Applications claim that BACT for NOx is an emission limit of 2.5 ppm, achieved with a selective catalytic reduction ("SCR") system and an ammonia slip of 10 ppm. This is not BACT for the project.

The applicant identified two NOx limits that are lower than the 2.5 ppm limit proposed for La Paz, 1 ppm and 2 ppm, but did not adopt either. BACT is "an emissions limitation... based on the maximum degree of reduction." 40 CFR 52.21(b)(12). The top-down guidance in the NSR Manual sets out a very strict standard that must be met when the top limit is not picked, as here, *viz.*, "In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record." (NSR Manual, pp. B. 26, B.29.) The reasons advanced by the applicant for selecting a lower limit are not justified.

First, the applicant argued that the lowest limit it found is based on lowest achievable emission rate ("LAER") criteria for a plant located in a nonattainment area in California. (Siting Application, p. B-1-11; Class I Application, p. F-10.) However, the top technology in the top-down BACT process is always LAER. (NSR Manual, pp. B.5, B.6.) LAER therefore must be included and evaluated in a top-down BACT analysis. Here, LAER clearly establishes BACT, because the same technology, SCR, can achieve NOx limits in the range of 1.0 to 2.5 ppm. SCR is cost effective over this entire range.

Second, the applicant concluded that 1 ppm was not BACT because it was based on SCONOx and then rejected SCONOx based on cost. The applicant argues that the 0.5 ppm NOx improvement allegedly achievable only by SCONOx, is very small compared to the overall increase in capital cost of SCONOx compared to SCR. (Siting Application, p. B-1-11; Class I Application, pp. F-9/10.) However, under the top-down process, this is not a valid reason to reject an emission limit. An emission limit can only be rejected for economic reasons if the cost is not in the range of normal costs for that alternative. (NSR Manual, §IV.D.2.) The cost-effectiveness that the applicant estimated for SCONOx, $6,806 per ton (*id.*, Table B-1.3),[2] is routinely considered to be cost-

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[2] This cost was revised upwards to $8,788/ton in the Class I Application. (Class I Application, Table F.3.) This is excessive, based on independent analyses done by other parties. SCONOx costs about $6,938/ton to reduce NOx from 25 ppm to 2 ppm on a GE Frame 7 machine. See ONSITE SYCOM Energy Corporation, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, Report Prepared for U.S. Department of Energy, October 15, 1999.

effective within Region 9 and consistent with costs borne by other applicants for similar projects in California.

Third, the applicant failed to evaluate whether 1 ppm NOx (or other limits lower than 2.5 ppm) could be achieved by another technology other than SCONOx. BACT is an emission limit, not a technology. Thus, a limit cannot be rejected simply because the technology that first achieved it is not cost effective when that limit can be achieved with another technology. The 2.5 ppm limit proposed by the applicant was originally demonstrated by SCONOx and many plants have been permitted at 2.5 ppm, but using SCR. SCR vendors will quote and guarantee a NOx limit of 1 ppm.

Finally, the applicant justifies its choice of 2.5 ppm because it is the "current permitted BACT for the majority of CTG/HRSG units with duct burners." (Siting Application, p. B-1-11; Class I Application, p. F-10.) BACT is the "maximum degree of reduction" that can be achieved, not the limit of the majority.

In addition to improperly excluding the highest limit, the applicant's BACT research, included in Exhibit B-1, Appendix B of the Siting Application and Appendix F2 of the Class I Application, is incomplete. The third step of the top-down BACT process requires that control technologies not eliminated in step 2 to be ranked and listed in order of overall control effectiveness. In the case of control technologies that can achieve a wide range of performance levels, such as SCR, "the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases." (NSR Manual, p. B.23.) The applicant did not consider a large number of recent regulatory decisions in other states that include lower NOx limits for turbines than the 2.5 ppm proposed here.

Table 1, attached herewith, updates and corrects the information collected by the applicant to include recent permitting decisions with lower NOx limits than proposed for this project. This table shows that the lowest NOx permit limit is 1.5 ppm averaged over 1 hour for the IDC Bellingham facility, based on a LAER determination in Massachusetts. This NOx limit has been achieved in practice using SCONOx at the Federal Facility in California and establishes BACT for this project since LAER is the top technology in a top-down analysis. Further, Table 1 shows that numerous permits have been issued with BACT limits of 2.0 averaged over 1 hour.

Table 1 demonstrates that NOx limits of 2.0 ppm averaged over 1 hour have been permitted in both nonattainment and attainment areas subject only to BACT (Sumas, Morro Bay). Region 9 recently commented that BACT for NOx "should be set at 2.0 ppmvd on a 1-hour rolling average" for the 600 MW Morro Bay project in California, located in an attainment area. (Ex. 1: Rios 6/19/01.) The permits for these two plants, which are located in attainment areas, are included in Exhibits 2 and 3. The ANP Blackstone facility in Massachusetts is operating. (Ex. 4.) Unit 1 started up in June and Unit 2 in July of 2001. The units have been source tested. The CEMs data and source tests indicate that NOx levels are well below the permit limit of 2 ppm averaged over 1 hour.[3]

Because BACT is the "maximum degree of reduction," the BACT analysis for this project must evaluate a NOx limit of no more than 1.5 ppm averaged over 1 hour. (The Nueva Azalea project, which proposed the 1 ppm limit reported by the applicant, has been suspended.) A 1.5 ppm limit can be achieved using SCR, which is proposed for this project. The cost effectiveness of SCR designed to reduce NOx to 1.5 ppm would be about the same as the cost-effectiveness for NOx at 2.5 ppm because the incremental increase in cost is small, compared to the increase in NOx reductions. Therefore, BACT for NOx for this project is 1.5 ppm averaged over 1 hour.

I.C Ammonia Slip Limit Is Not BACT

Unreacted ammonia is emitted from the SCR system. This unreacted ammonia is typically referred to as "ammonia slip." The Applications indicate that ammonia emissions would be limited to 10 ppm. (Siting Application, p. B-1-1 and Ex. B-1, Appx. H; Class I Application, p. F-6.) The supporting documentation indicates that the applicant arbitrarily set the ammonia slip limit at 10 ppm without performing a top-down analysis or providing any justification. The ammonia slip limit is part of the BACT determination for NOx and is normally evaluated as part of the NOx BACT analysis as a collateral impact, and/or in a separate ammonia BACT analysis. The applicant has done neither. The information presented below indicates that BACT for ammonia slip for this project is 2 ppm averaged over 1 hour and monitored by CEMs.

The RACT/BACT/LAER Clearinghouse ("RBLC") lists ammonia slip BACT limits ranging from 3.5 ppm to 10 ppm. Lower slip levels have been permitted, guaranteed by vendors, and demonstrated in practice as demonstrated in the Morro Bay permit in Exhibit 3, and Massachusetts permits available at http://www.state.ma.us/dep/energy/sites.htm. Based on limits achieved in practice and permitted elsewhere, the ammonia BACT level for this project should be no higher than 2 ppm averaged over 1 hour.

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[3] Personal communication, Gary Roscoe, MA DEP, 508-767-2773, October 9, 2001.

Very low slips have been achieved in practice at a number of facilities. The 248-MW River Road Generating Facility in Vancouver, Washington, has consistently demonstrated ammonia slip levels of 0.01 ppm to 0.2 ppm over a three-year period, corresponding to guaranteed catalyst life. (Ex. 5.) The Crockett Cogeneration Facility in California has consistently achieved ammonia slip levels of less than 1 ppm. (Ex. 6.) The Hitachi letter in Exhibit 7[4] identifies a 1400-MW LNG-fired plant consisting of four GE Frame 9 gas turbines that is currently operating at a NOx level of 3 ppmvd with a 3 ppmvd ammonia slip in Japan. The ANP Blackstone facility in Massachusetts is currently achieving a slip of less than 1 ppm with a NOx level of less than 2 ppm,[5] demonstrated by a CEMs. (Ex. 4.)

Massachusetts has established a 2 ppm ammonia slip BACT limit for new power plants. The Massachusetts Department of the Environmental Protection ("MDEP") has established a "Zero Ammonia Technology" BACT standard for gas turbines larger than 50 MW. See Exhibit 4. Five large projects in Massachusetts have been issued PSD permits specifying a NOx limit of 2 ppm achieved with a 2 ppm ammonia slip, demonstrated using an ammonia CEMs and both averaged over 1 hour (Table 1). These permits require that they retrofit with zero ammonia technology at the end of five years if certain criteria are met. One of these permits is provided in Exhibit 4. The balance can be found at http://www.state.ma.us/dep/energy/sites.htm. The Morro Bay facility was recently permitted in California with a slip limit of 2 ppm. (Ex. 3.)

I.D BACT For CO Emissions Not Required

The Siting and Class I Applications indicate that CO would be controlled to 5 ppm during normal operations, using an oxidation catalyst. (Siting Application, pp. APP-2, B-1-14; Class I Application, Table 14.1 and p. F-14.) For the reasons set out below, this is not BACT for CO.

The applicant's supporting documentation identified four facilities that have been permitted with lower limits, Newark Bay Cogeneration at 1.8 ppm, Wyandotte Energy at 3 ppm, Saranac Energy at 3 ppm, and Brooklyn Navy Yard at 4 ppm. (Siting Application, Ex. B-1, Appx. C; Class I Application, Appx. F3.) BACT is "an emissions limitation...based on the maximum degree of reduction." 40 CFR 52.21(b)(12). The top-down guidance in the NSR Manual sets out a very strict standard that must be met when the top limit is not picked, as here, *viz.*, "In

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[4] Letter from John Calvello, Hitachi America Ltd., to Phyllis Fox, Environmental Management, Re: Catalyst Information, August 13, 1998.

[5] Personal communication, Gary Roscoe, MA DEP, 508-767-2773, October 9, 2001.

the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record." (NSR Manual, pp. B. 26, B.29.) The applicant attempts to justify the 5 ppm CO limit by advancing a number of arguments similar to those used for NOx that are technically incorrect.

First, the applicant argued that the lowest limits that it found are based on lowest achievable emission rate ("LAER") criteria for plants located in nonattainment areas in California. (Siting Application, p. B-1-14.) However, the top technology in the top-down process is LAER. (NSR Manual, pp. B.5, B.6.) LAER must be included and evaluated. Here, LAER clearly establishes BACT, because the same technology, SCR, can achieve lower CO limits in the range of 1.0 to less than 5 ppm and is cost effective. Further, as discussed below, 18 similar projects have been permitted in attainment areas with lower CO limits.

Second, the applicant suggests that only "more costly and unproven emerging technologies" such as SCONOx and XONON can meet a lower limit than 5 ppm. (Siting Application, p. B-1-14.) This is not true. Further, the applicant argues that "the sources that have been permitted with less than 6 ppm CO are very recently permitted facilities with little or no operational data for review to decide the applicability of "demonstrated in practice" for determining BACT." (Class I Application, p. F-14.) This is also not true. There is an abundance of source test and CEMs data that demonstrate that very low CO limits, much lower than the proposed 5 ppm limit, are both "demonstrated in practice" and "achieved in practice."

For example, continuous emission monitor ("CEM") data for the River Road Generating Project in Vancouver, Washington demonstrate that an oxidation catalyst can routinely meet a CO limit of 1.2 ppm averaged over 1 hour. This facility is a 248-MW natural gas fired, combined-cycle plant consisting of a GE 7231 FA gas turbine equipped with GE dry low-NOx combustors (DLN III), an unfired HRSG, and a steam turbine. Control equipment includes an SCR system and an oxidation catalyst guaranteed by the vendor at 3 ppmvd at 15% O_2 and permitted at 6.0 ppmvd at 15% O_2 averaged over 1 hour. The unit operates at loads from 75% to 100%, and experiences frequent shutdowns and startups.

The CEMs data for seven quarters from October 1998 through December 2000[6] in Figure 1 indicate that the River Road Generating Station routinely achieves a CO limit of 1.2 ppm averaged over 1 hour. The maximum 1-hour average over this period of record is 1.13 ppm (Fig. 1) and 0.5 ppm averaged over

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[6] The fourth quarter of 1999 is missing from the SWAPCA's files.

3 hours (Fig. 2). Over this period, the facility operated 7,890 hours out of a possible 8,784 hours (2000 was a leap year). All exceedances of these limits were due to startups, shutdowns, operator error, or equipment malfunctions reported to the local regulatory agency.

Third, the applicant failed to evaluate whether a lower CO limit than 5 ppm could be achieved by technology other than SCONOx, even though it admitted that lower limits had been permitted. (Siting Application, Table B-1.4; Class I Application, Table F.4.) As explained previously, BACT is an emission limit, not a technology. Thus, a limit cannot be rejected simply because the technology that initially achieved it is not cost effective if that limit can be achieved with another technology. Oxidation catalyst vendors will quote and guarantee 90% to 95% CO removal. This would correspond to a CO limit of 1.25 to 2.5 ppm. The applicant is only proposing 80% CO removal, which is clearly not BACT.

Fourth, the Class I Application concluded that the cost of SCONOx was excessive to control CO and therefore eliminated it from the analysis. (Class I Application, p. F-14.) However, the costs of SCONOx were overestimated. Further, the applicant failed to address the fact that SCONOx removes four classes of pollutants - NOx, CO, VOCs, and HAPs. The BACT cost-effectiveness analysis should evaluate costs relative to total pollutant removal, not relative to each pollutant individually. See ONSITE SYCOM Energy 10/15/99, cited in footnote 2.

Finally, the applicant's BACT search is not complete. Many more facilities have been permitted (and source tested) with lower CO limits than those proposed for the La Paz Project. EPA Region 2 recently summarized several CO BACT limits that are between 2 ppm and 4 ppm and suggested a proposed plant in New York should either meet these limits or demonstrate why they could not be achieved. (Ex. 8: Riva 9/27/00.[7])

EPA Region 9 recently concluded that "presumptive BACT for CO" in an attainment region for the similar Morro Bay project (Ex. 3) is 2.0 ppmvd based on a 3-hour rolling average. (Ex. 1: Rios 6/19/01.) The local permitting authority concurred and issued a final permit with a CO limit of 2.0 ppm averaged over 3 hours, in a CO attainment area. Other recent permit decisions summarized in

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[7] Letter from Steven C. Riva, Chief, Permitting Section, EPA Region 2, to Robert L. Ewing, New York State Department of Environmental Conservation, Re: PSD Proposed Sithe Heritage station Generating Facility, Scriba, New York, September 27, 2000.

Table 2 indicate that CO limits of 2 ppm to 4 ppm, achieved using an oxidation catalyst, are routinely permitted in CO attainment areas.

I.E BACT For VOCs From Gas Turbines Not Required

The project proposed a VOC BACT limit of 2.9 ppm in the Siting Application. (Siting Application, p. B-1-21.) This was increased to 3.11 in the Class I Application. (Class I Application, p. F-23.) This is higher than VOC concentrations routinely permitted and achieved in source tests elsewhere. As discussed above for both NOx and CO, although the applicant identified lower permitted VOC limits, it failed to evaluate these lower levels in its BACT analysis. Further, the applicant failed to identify many lower limits contained in recent permits, which have been confirmed by source tests.

A large number of combined cycle projects using large GE or Westinghouse Frame 7 turbines have been permitted recently in both Massachusetts and California at 1 to 2 ppmvd @ 15% O_2. In California, these include the Sutter Project (2 Westinghouse 501F turbines),[8] Otay Mesa (turbines not selected),[9] and Metcalf (2 Westinghouse 501F turbines).[10] VOC permit limits for other California projects can be found on the California Energy Commission website at http://www.energy.ca.gov in Final Determinations of Compliance or Commission Decisions for individual project. *See, for example,* the following additional California projects: Delta Energy Center, Moss Landing Power Project (Duke), Elk Hills Power Project, Sunrise, La Paloma Generating Project, Blythe Energy Power Project, High Desert Power Project, Three Mountain Power Project, and Western Midway Sunset Power Project. In Massachusetts, these include the Island End Cogeneration Facility (one Westinghouse 501G),[11] the

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[8] See http://arbis.arb.ca.gov/bactdb/Search.exe, gas turbines > 23 MMBtu/hr heat input, Sutter Power Plant. VOC/HC BACT limit is 1 ppmvd @ 15% O_2 on a calendar day average.

[9] San Diego Air Pollution Control District, Final Determination of Compliance, Otay Mesa Generating Stations, September 18, 2000, Permit Engineer: Steve Moore (858-650-4598). Turbine not selected, but permit covers two ABB GT-24s, two GE Frame 7FAs, or two Westinghouse 501 FDs. The VOC BACT permit limit is 2.0 ppmvd @ 15% O_2 based on a 1-hour rolling average.

[10] Bay Area Air Quality Management District, Final Determination of Compliance, Metcalf Energy Center, August 24, 2000, Permit Engineer: Dennis Jang. The VOC permit limit is 0.00126 lb/MMBtu as CH4 or 2.7 lb/hr, which is equivalent to 1.0 ppm.

[11] See www.state.ma.us/dep/energy/iend/permitstat.htm. The VOC permit limit is 2.0 ppm @ 15% O_2 and 0.003 lb/MMBtu.

Mystic Station Redevelopment Project (2 MHI 501G),[12] and the ANP Blackstone Energy Project (two ABB GT-24s).[13]

Source test results on similar large Frame 7 turbines indicate that much lower emission limits are achieved in practice. Table 3 summarizes 19 source tests on seven Frame 7 turbines producing greater than 160 MW at five separate power plants in three states. These source tests demonstrate that turbines identical to those proposed for this project, routinely achieve VOC emission limits of less than 1 ppm @ 15% O_2.

II. BACT NOT REQUIRED FOR AUXILIARY BOILER

The project includes a 55.34 million Btu per hour ("MMBtu/hr") auxiliary boiler fired on natural gas. The proposed NOx and CO BACT limits are much higher than limits that have been permitted and achieved in practice.

II.A BACT For NOx From Auxiliary Boiler Not Required

The applicant proposed a NOx limit of 0.1 lbs/MMBtu for the auxiliary boiler in the Siting Application, which corresponds to a NOx concentration of 82 ppmvd @ 3% O_2. (Siting Application, p. B-1-24.) This was lowered to 0.036 lb/MMBtu in the Class I Application. This limit would be achieved using a conventional low NOx burner with about 10% flue gas recirculation. (Class I Application, Table 14.1 and Appx. B-3, 5/16/01 Forney letter.) This is a very high limit for a boiler and does not represent BACT. The applicant failed to explain why lower limits that it reviewed do not establish BACT, failed to identify all relevant BACT determinations, and incorrectly concluded that SCR is not feasible.

II.A.1 <u>Lower NOx Limits Have Been Permitted and Demonstrated</u>

Lower NOx limits than 0.036 lb/MMBtu (about 30 ppm @ 3% O_2) have been established and published in BACT Clearinghouses maintained by the California Air Resources Board ("CARB") and the South Coast Air Quality Management District ("SCAQMD"). The NSR Manual specifically recommends that the SCAQMD database, as well as other sources, be consulted in making

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[12] See www.state.ma.us/dep/energy/mystic/stmys.htm. The VOC permit limit is 1.0 ppmvd @ 15% O_2 and 0.0013 lb/MMBtu unfired and 1.7 ppmvd @ 15% O2 and 0.0022 lb/MMBtu with duct firing.

[13] See www.state.ma.us/dep/energy/black/stbl.htm. The VOC permit limits is 1.4 ppm @ 15% O_2 and 0.0018 lb/MMBtu at 75% to 100% load and 2.5 ppm @ 15% O2 and 0.0032 lb/MMBtu at 50% load.

BACT determinations. (NSR Manual, p. B.11.) Boiler determinations from CARB's database in Exhibit 9 and the SCAQMD's database in Exhibit 10 show that the applicant's list of BACT determinations is not complete. Some of the lower BACT determinations from these additional sources are discussed below.

The applicant proposes a NOx limit of 30 ppm at 3% O_2, achieved with low-NOx burners and 10% flue gas recirculation. Low-NOx burners are capable of meeting much lower limits, from 9 to 30 ppm, as demonstrated by the Coen application list and case histories in Exhibit 11. Recent advances in burner technology allow low-NOx burners to meet 9 ppm NOx.

Ultra low-NOx burners have also been installed and successfully used on many boilers, as demonstrated by the Radian/Todd installation list in Exhibit 12. These burners can achieve NOx limits of 7 ppm to 9 ppm, as demonstrated by the source test data included in Exhibits 13 and 14 (Appx. A).

Three 40,000 lb/hr Foster-Wheeler auxiliary boilers at the Crockett Cogeneration Facility in California were permitted at 8.2 ppm NOx @ 3% O_2 in 1996, achieved using SCR with a 20 ppm ammonia slip. The June 1997 source test measured 5.47 ppm NOx and 4.92 ppm NH_3 from Boiler B and the June 1998 source test measured 5.39 ppm NOx and 5.84 ppm NH_3 from Boiler C, all reported at 3% O_2. (Ex. 15.)

A 31.5-MMBtu/hr Scotch Marine fire tube boiler was permitted by the SCAQMD in December 1999 at 7 ppm NOx @ 3% O_2, achieved using low-NOx burners and SCR with a 5 ppm NH_3 slip. A second similar 21-MMBtu/hr Cleaver Brooks fire tube boiler was permitted by the SCAQMD in August 2000 at 7 ppm NOx @ 3% O_2 averaged over 15-minutes, achieved using SCR with a 5 ppm NH_3 slip averaged over 15-minutes. (Ex. 10.) Source tests for a similarly equipped 100-MMBtu/hr boiler at Darling Delaware in Los Angeles achieved NOx emissions of 6-7 ppm. (Ex. 14, Appx. A.)

A 56-MMBtu/hr auxiliary boiler at a cogeneration facility in the Equilon Refinery, Martinez, California was permitted by the BAAQMD in December 1993 at 5 ppm NOx @ 3% O_2, achieved using SCR. The unit has been successfully source test. (Ex. 14, Appx. A.)

A 20-MMBtu/hr Unilux dual-fuel boiler at the Federal Prison in Victorville, CA was permitted by the Mojave Desert Air Quality Management District in October 2000 at 5 ppm NOx @ 3% O_2, achieved using SCR. The unit has been successfully source tested and the limit confirmed by CEMs data. (Ex. 16.)

Based on the foregoing, much lower NOx limits than established for La Paz as BACT have been routinely guaranteed by vendors, permitted, and demonstrated in source tests and with CEMs data. Although all of these permitting decisions were made in nonattainment areas, LAER is the top technology in the top-down BACT process. Thus, the presumptive BACT level for the auxiliary boiler is a NOx limit of 5 ppm @ 3% O_2, achieved using SCR with a 5 ppm NH_3 slip. The BACT analysis should be revised to consider these limits.

I.A.2 <u>SCR Is Technically Feasible</u>

The applicant claims that SCR is technically infeasible because the boiler exhaust gas temperature of 350 F is outside of the temperature range of 700 F to 900 F required for SCR. (Class I Application, p. F-25.) This is incorrect. A wide range of SCR catalyst formulations are available that can be matched to exhaust temperature, as demonstrated by the large number of SCR systems that are being successfully used on similar low-temperature boilers. Information for one low temperature SCR system, offered by CRI Catalyst, a division of Royal Dutch Shell, is included in Exhibit 17. CRI Catalyst supplied the low-temperature SCR systems currently in use on the Crockett Cogeneration auxiliary boiler (Ex. 15) and the Federal Prison boiler (Ex. 16.)

II.B BACT For CO From Auxiliary Boiler Not Required

The applicant proposed a CO limit of 0.06 lb/MMBtu in the Siting Application. (Siting Application, p. B-1-25.) This was increased to 0.14 lb/MMBtu in the Class I Application. (Class I Application, p. F-27.) This corresponds to a CO concentration of about 150 ppm CO at 3% O_2. The applicant argued that an oxidation catalyst could not be used to achieve a lower limit because the exhaust temperature is too low. Oxidation catalysts have been installed on hundreds of utility and other boilers, as demonstrated by the experience list of one vendor. (Ex. 18.)

The applicant identified two BACT limits that are lower than proposed, 0.02 and 0.05 lb/MMBtu. (Class I Application, Appx. F7.) My review of the RBLC indicates that there are three other boilers that have been permitted with lower CO limits, ranging from 0.015 to 0.05 lb/MMBtu. The applicant provides no justification for not proposing the lowest reported limits on this project, consistent with the definition of BACT and federal guidance.

Much lower limits than 0.14 lb/MMBtu have been achieved using low-NOx burners (Exs. 9, 10), ultra-low NOx burners (Ex. 13), and oxidation catalysts (Exs. 15, 18), which have been installed on hundreds of utility and other boilers and are thus presumptive BACT unless specifically demonstrated to be infeasible in this case. The record contains no such demonstration.

Three 40,000 lb/hr Foster-Wheeler auxiliary boilers at the Crockett Cogeneration Facility in California were permitted at 11 ppm CO @ 3% O_2 in 1996, achieved using an oxidation catalyst. The June 1997 source test measured 3.24 ppm @ 3% O_2 from Boiler B and the June 1998 source test measured 6.02 ppm @ 3% O_2 from Boiler C. (Ex. 15.) These boilers establish BACT for the auxiliary boiler for this project.

III. MINOR SOURCES

The project includes two 1,000 kW generators and a 254-bhp emergency firewater pump that will be fired on diesel. The Siting and Class I Applications do not contain a BACT analysis for these sources, instead arguing that any controls would not be cost effective and that, at any rate, that the analysis would be identical to that for turbines and heat recovery steam generators. (Siting Application, p. B-1-28; Class I Application, p. F-29.) These claims are incorrect.

III.A BACT Not Required For Minor Sources

Similar engines permitted in Massachusetts, Nevada, and California have included oxidation catalysts to control CO and VOCs, SCR to control NOx, and particulate traps to control PM10 (Table 4).

There are hundreds of diesel generators in operation around the world that are controlled by SCR systems designed to remove 80% to over 95% of the NOx. Most of the operating units are in Europe and Japan, although there are also many installations in the United States. These systems are offered by a number of vendors including Steuler (Ex. 25), Miratech (Ex. 26), Johnson Matthey (Ex. 27), and Engelhard (Ex. 28), among others. Descriptions of the products offered by these vendors and installation lists are included in the cited exhibits, where available. The HUG vendor list in Exhibit 26 indicates that lower limits than those that have been permitted in the U.S. (Table 4) have been permitted and achieved in practice on engines currently operating in Europe. Steuler, Miratech, and Engelhard indicate that they will guarantee NOx reductions of 99+% on emergency diesel engines, which would yield an emission limit of <0.069 g/bhp-hr on a new, 6.9 g/bhp-hr certified diesel engine.

The HUG list in Exhibit 26 ("Reference list January 2001 Stationary Combustion Engines") separately indicates whether an SCR, oxidation catalyst ("OXI"), or particulate filter ("filter") is installed. Many engines include either two or all three of these post-combustion controls. Further, most vendors of SCR systems for IC engines include a layer of oxidation catalyst to simultaneously control CO emissions. See, for example, the literature describing the Miratech SCR system (Ex. 26) and the Engelhard SCR system (Ex. 28). Thus, both NOx and CO can be controlled by using an SCR system formulated with an oxidizing layer.

Therefore, these controls are considered cost-effective unless site- and source-specific factors are documented that make this facility unique. (NSR Manual, § 4.D.2.) Further, this facility will likely require a federal PSD permit from Region 9, which requires a BACT analysis for minor sources.

Best available control technology applies to the entire stationary source (40CFR 52.21(b)(12)), which is defined to include "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person." 40 CFR 52.21(b)(5) and (6).

Therefore, a BACT analysis should have been performed for each of the minor sources. Very low limits have been permitted for NOx, CO, and PM10 for similar sources, as demonstrated by Table 4. The emission limits in this table establish the top technology for a top-down BACT analysis.

III.B Fuel Sulfur Content Of 0.05% Not BACT For Diesel Engines

Diesel fuel containing 0.05% sulfur (500 ppm) and good combustion practices are proposed as BACT for SO_2 for the diesel engines without performing a BACT analysis. (Siting Application, p. B-1-28.) However, lower sulfur diesel is available and cost effective and should have been evaluated and adopted as BACT.

The average sulfur content of Arizona diesel is 268 ppm. (ADEQ 11/9/00,[14] p. 10.) Lower sulfur fuels, as low as 15 ppm, have been required elsewhere, where available. The BACT guidelines for fuel sulfur for diesel generators in some areas of California (e.g., the SJVUAPCD) require the use of <15 ppmw diesel, when available. The California Energy Commission ("CEC") has required the use of ultra low sulfur fuel where available, including in the recently decided cases of Three Mountain Power[15] and Huntington Beach

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[14] Arizona Department of Environmental Quality (ADEQ), Off-Road Mobile Controls Subcommittee, Final Report, Revised November 9, 2000.

[15] California Energy Commission, Commission Decision, Three Mountain Power Plant Project, May 2001, Condition AQ-26, p. 142.

(exclusive use of 15 ppm S fuel).[16] Similarly, New York is currently adopting regulations that will require the use of ultra low sulfur fuel for diesel generators.[17]

Ultra low sulfur fuels are currently available in the South Coast and could be imported to the site for a premium of about 10 to 15 cents per gallon. Further, the EPA has adopted stringent fuel regulations that limit the sulfur content of diesel fuel to 15 ppmw. These regulations go into effect in June 2006, at which point ultra low sulfur diesel will be widely available in Arizona.

Therefore, the applicant should perform a BACT analysis for fuel sulfur (as a surrogate for SO_2 emissions), and as part of this analysis investigate the current availability of ultra low sulfur diesel. The applicant should agree to use < 30 ppm sulfur diesel, when available, but no later than June 2006.

EMISSIONS

IV. SULFURIC ACID MIST EMISSIONS NOT CONSIDERED

The combustion of fuels containing sulfur in gas turbines converts the fuel sulfur into a mixture of gaseous sulfur dioxide (SO_2) and sulfur trioxide (SO_3). The SO_3 combines with water to form sulfuric acid mist ("SAM") or H_2SO_4. The SO_3 and/or SAM is captured as sulfate on filters (front half) or in aqueous impingers (back half) of the standard PM10 test (Method 201/202), and thus contributes to PM10. The PSD significance threshold for sulfuric acid mist is 7 tons/year. The La Paz Project exceeds this threshold, and thus triggers PSD review and a BACT analysis for SAM.

Neither the Siting nor the Class I Permit Applications determined whether the project would comply with prevention of significant deterioration ("PSD") regulations for SAM emissions from the turbines or other sources.[18] The percent conversion of fuel sulfur to SAM in gas turbines based on 13 source tests is summarized in Table 5.[19] This table shows that the conversion rate ranges from

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[16] California Energy Commission, Commission Decision, Huntington Beach Generating Station Retool Project, May 2001, Condition AQ-C2, p. 30.

[17] New York State Department of Environmental Conservation, DEC to Regulate Emissions from Distributed Generation, May 3, 2001 www.dec.state.ny.us/website/press/pressrel/2001-69.html.

[18] The Class I Application did include SAM in its analysis of Arizona AAAQGs. (Class I Application, Table 3.7.)

[19] Some of these source test results were provided under terms of confidentiality. If the District wishes to review copies, we can arrange for a formal request to the appropriate entities.

3.4% to 100% and averages 54%. The project would emit 78 ton/yr of SO_2.[20] (Siting Application, Table B-1.13.) This amounts to 100% of the sulfur present in the fuel, or 39 ton/yr of sulfur. Assuming an average 54% conversion, the potential to emit SAM would be 64.5 tons/year.[21] We note that the applicant assumed 70% conversion of SO_2 to SAM in its analysis of AAAQGs. (Class I Application, Table 3.7, last note.) Thus, the PSD significance threshold of 7 ton/yr is exceeded by a large amount. However, neither of the applications I reviewed contain any analysis of the project's compliance with PSD regulations for SAM. A BACT analysis, for example, must be conducted and BACT imposed. SAM emissions can be controlled by using a lower sulfur natural gas or by installing a fuel gas scrubber to remove sulfur before it is combusted in the turbines and other sources.

V. HAZARDOUS AIR POLLUTANTS

The applicant substantially underestimated emissions of hazardous air pollutants ("HAPs") for this project. This is evident for two reasons. First, the applicant inappropriately use SCONOx emission factors for the compounds emitted in the largest amounts. Second, it did not consider the substantial increase in HAPs that occurs during startups and shutdowns due to degradation in turbine performance. As described below, when the proper emission factors are used and/or startup emissions are included, project emissions exceed federal maximum achievable control technology ("MACT") standards.

V.A HAP Emission Estimates

Emissions are calculated by multiplying the heat rate by an emission factor, which expresses the amount of pollutant emitted per unit of fuel combusted, e.g., in pounds per million BTUs ("lb/MMBTU"). These emissions are then used below to evaluate compliance with federal and state HAPs regulations.

The applicant estimated emissions using U.S. EPA emission factors from AP-42 and the California Air Resources Board ("CARB") CATEF database. (Siting Application, p. B-1-32.) The supporting emission spreadsheets in the Siting Application, Exhibit B-1, Appendix H, indicate two fatal flaws, discussed below.

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[20] The Class I Application reduces annual emissions to 76.4 ton/yr. (Class I Application, Table 3.2.)

[21] The potential to emit SAM assuming 54% conversion to H_2SO_3 = [(0.54)(78 ton/yr)(98 ton H_2SO_4/64 ton $SO_{2)}$ = 64.5 ton H_2SO_4/yr. This would drop to 63.2 ton/yr for the revised SO_2 emissions in the Class I Application.

V.A.1 SCONOx Emission Factors

The HAPs that are emitted in the largest amounts from gas turbines are formaldehyde and acetaldehyde. The applicant used an emission factor based on SCONOx to estimate emissions of these two compounds. (Siting Application, Appx. H, Table 2, HAP Emission Factors; Class I Application, Appx. B-5, Table 2, note a.) However, the applicant is proposing an oxidation catalyst to control VOCs, not SCONOx. The SCONOx source test indicates that SCONOx removes 97% of the formaldehyde and 94% of the acetaldehyde. (Siting Application, Ex. H, 8/19/99 EPA Memo.)

The oxidation catalyst vendor's data, on the other hand, indicates that an oxidation catalyst only removes 77% of the formaldehyde. (Ex. 29: Heck and Farrauto 1995,[22] Table 11.1.) Further, formaldehyde conversion, as quoted by the major vendor, is typically 2% to 3% less than the guaranteed CO conversion rate. (Ex. 30.) According to the Siting Application, the oxidation catalyst would be designed for a maximum of 80% CO removal. (Siting Application, Appx. H, B&V Emission Summary.) Therefore, it would remove, at most 77% of the formaldehyde.

Thus, assuming only 77% control of formaldehyde, the emissions of formaldehyde from the turbines/HRSG would increase from 0.75 ton/yr reported by the applicant (Siting Application, Appx. H, Table 3, Annual HAP Emissions) to 5.5 ton/yr.[23] Ignoring the minor contribution of formaldehyde from the duct burners, this would increase total HAP emissions from 21.7 ton/yr reported in the Siting Application[24] to 26.4 ton/yr.[25] As discussed below, this exceeds the MACT threshold of 25 ton/yr for total HAPs and requires that a MACT analysis be performed and that additional controls be required.

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[22] Ronald M. Heck and Robert J. Farrauto, Catalytic Air Pollution Control, Commercial Technology, Engelhard Corporation, Research & Development, Van Nostrand Reinhold, 1995.

[23] Revised formaldehyde emissions = $(7.1\times10^{-4}$ lb/MMBtu)(1-0.77)(1910.9 MMBtu/hr per turbine)(4 turbines)(8760 hr/yr)/2000 lb/ton = 5.47 ton/yr. The uncontrolled formaldehyde emission factor is from AP-42, Table 3.1-3. The control efficiency, 77%, is from Heck and Farrauto, 1995 (Ex. 29), and Engelhard budgetary quotes in Exhibit 30. The firing rate, 1,910.9 MMBtu/hr per turbine, is from the Class I Permit Application, Table 5.2.

[24] The HAP emissions were revised to 21.1 ton/yr in the Class I Application. (Class I Application, Table 3.8.)

[25] Adjusted total HAP emissions = 21.7 - 0.75 + 5.5 = 26.45 ton/yr.

V.A.2 Startup And Shutdown Emissions

The emission factors used by the applicant do not consider the dramatic increase in emissions during startups. The HAP emission estimates were calculated using emission factors that assume full load operation. However, it is well documented that turbine performance, in terms of combustion efficiency, degrades as load decreases. Turbines are designed to run efficiently at full load where fuel combustion is nearly 100% efficient. At lower loads, and during startup, turbines are extremely inefficient,[26] which results in incomplete combustion.[27]

The applicant is proposing 50 cold starts lasting 284 minutes each, 50 warm starts lasting 185 minutes each, and 50 hot starts lasting 116 minutes each for each turbine. Therefore, the plant will experience startup conditions for 487.5 hr/yr or about 6% of the run time, assuming an annual two-week maintenance outage. The plant will also experience an equivalent number of shutdowns. The shutdowns are not considered here because they are of much shorter duration and emission increases are lower.

Reduced turbine efficiency increases the emission of products of incomplete combustion, such as carbon monoxide ("CO"), aldehydes, and hydrocarbons. (Ex. 31: GRI/EPRI, 1996;[28] FAA, 1995[29]). The former study was sponsored by industry -- the Gas Research Institute ("GRI") and the Electric Power Research Institute ("EPRI"). The study characterized HAP emissions from a variety of gas-fired power generation units as a function of load. The Federal Aviation Administration ("FAA") database consists of aircraft engine (both turbine and piston engine) vendor performance test data that is collected as part of the FAA engine certification process.

These two studies summarize source test data for power generation and industrial gas turbines and aircraft turbines under a variety of load conditions. The data from the GRI/EPRI study are plotted in Figures 3 through 6 to illustrate

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[26] R. H. Kehlhofer, J. Warner, H. Nielsen, and R. Bachmann, Combined-Cycle Gas Steam Turbine Power Plants, 2nd Ed., PennWell, Tulsa, OK, 1999, Chapter 8: Operating and Part Load Behavior.

[27] A. H. Lefebvre, Gas Turbine Combustion, 2nd Ed., Taylor & Francis, Philadelphia, PA, 1998, Sec. 9-4, Mechanisms of Pollutant Formation.

[28] Gas Research Institute ("GRI") and Electric Power Research Institute ("EPRI"), 1996. Gas-Fired Boiler and Turbine Air Toxics Summary Report. Prepared by Carnot Technical Services for GRI and EPRI, August 1996.

[29] Federal Aviation Administration ("FAA"), FAA Aircraft Engine Emission User Guide and Database, FAA Office of Environment and Energy.

how turbine emissions increase as load decreases as a result of poor combustion. All of these turbines were gas fired. Figure 3 plots the data for CO, Figure 4 plots the data for hydrocarbons, Figure 5 plots the data for formaldehyde, and Figure 6 plots the data for benzene. Figure 7 presents CO and hydrocarbon data for two GE aircraft turbines that were fired on jet fuel (similar to diesel). While aircraft turbines are smaller, are configured differently than electric generating turbines, and use different fuel, the emission profiles as a function of load are remarkably similar to the GRI/EPRI study emission profiles for electric generating turbines, confirming the relationship between load and emissions for turbines. This relationship has also been noted by the U.S. EPA in its work to establish MACT standards for the gas turbine source category. (EPA 4/14/98.[30])

All of these figures express emission factors as a percentage of the minimum load, i.e., as the ratio of the emission factor at 25% load to the emission factor at 100% load, expressed as a percent. Typically, startup is assumed to take place between 0% to 50% load. Therefore, the minimum load in these figures is assumed to be 25%. For example, in Figure 3 the CO emission factor for the GE Frame 7 turbine at 100% load is only about 0.1% of the emission factor at 25% load. Based on the fuel input rates at these load levels, which decrease proportionately with load, CO emissions at 25% load would be 318 times those at full load. Similarly, formaldehyde emissions at 25% load are 503 times higher than at 100% load.

The magnitude of emission increases with load reduction varies by pollutant, but is remarkably similar regardless of turbine type, following the same type of power relationship of the form $y = ax^n$, where y is the emission factor and x is percent load. The net result is that emissions of carbon monoxide, hydrocarbons, and the toxic byproducts that form as a result of incomplete hydrocarbon combustion, increase dramatically as load decreases.

I used uncontrolled EPA emission factors and adjusted them to include an oxidation catalyst and startup emissions. Startup emissions were estimated by adjusting the uncontrolled EPA emission factors using the GRI/EPRI data for the 150-MW GE Frame 7 turbine, the most similar turbine to the 200-MW Westinghouse 501F turbines proposed for La Paz. The GRI/EPRI study shows that the emission factor for this turbine for formaldehyde increases by a factor of 503, benzene by a factor of 8, toluene by a factor of 10, and other organics by a factor of 1.4 at 30% load compared to 100% load. (Ex. 31.) These ratios, shown in

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[30] U.S. EPA, Rationale for Development of MACT Floor for Existing Combustion Turbines, April 14, 1998.

the second column of Table 6, are multiplied by the 100% load turbine emission factors to estimate startup emission factors.

These calculations assume that the turbines would be at 30% load throughout the startup period to simplify calculations. The actual startup profiles are somewhat different and would result in higher emissions than assumed here. Westinghouse startup curves included in Exhibit 32, for example, indicate that during a cold startup, the gas turbine would be held at 8% or lower load for the first 28 minutes, while during a warm startup, the turbine would be at 25% load or lower for 62% of the time.

The applicant used controlled HAP emission factors when available and otherwise ignored the presence of an oxidation catalyst. Startup emissions would be significantly overestimated if the control afforded by the oxidation catalyst during startup were not considered. Therefore, I uniformly adjusted uncontrolled EPA emission factors to account for the presence of an oxidation catalyst.

Generally, an oxidation catalyst designed to control CO, as here, would be less efficient in controlling HAPs, which are volatile organic compounds ("VOCs"). This is demonstrated by the Engelhard performance curves, which plot catalyst temperature versus conversion efficiency in percent. The VOC curve in Exhibit 33 shows that for temperatures ranging from 600 F to 700 F, typical of most oxidation catalysts installed in HRSGs, the VOC removal efficiency would be roughly half the removal efficiency of CO. Here, the oxidation catalyst would be designed to remove 80% of the CO. Therefore, I conservatively assumed that the oxidation catalyst would also remove 80% of each organic compound. The data in Exhibits 29 and 33 indicate that this is a substantial overestimate of the likely removal efficiency for individual HAPs. This assumed efficiency should be assured by designing and warranting the catalyst to meet these specifications and confirmed in a series of source tests over the life of the catalyst.

The oxidation catalyst does not start operating until it reaches a minimum temperature, typically around 500 F and does not reach its guaranteed efficiency until gas temperatures reach the design point. The catalyst is warmed up during startup by the hot turbine exhaust gases. During cold starts, when the plant has been down at least 72 hours, the catalyst starts out at near ambient and is gradually brought up to temperature by hot turbine exhaust gases flowing across its surface. Performance curves for cold starts of Frame 7 turbines indicate that it takes about 20 minutes for the turbine exhaust gases to reach 500 F. During hot starts, the catalyst starts out warm and is more quickly brought up to operating temperature. The actual length of time it would take the catalyst to reach operating temperature would depend on how long the plant is down. However, vendors indicate that the catalyst typically reaches operating temperature in as little as 5 minutes during normal hot starts. Therefore, the revised calculations assume that the first 20 minutes of each cold start, 10 minutes of each warm start, and 5 minutes of each hot start are uncontrolled. The catalyst is conservatively assumed to remove 80% of all HAPs for the balance of the startup period.

The revised HAP emissions are summarized in Table 7 for a single turbine. These calculations show that 87% of the HAP emissions occur during startups and only 13% during full load operation. Of the total, 21% of the HAP emissions is uncontrolled and emitted before the catalyst reaches operating temperature. Formaldehyde is emitted in the largest amount, comprising 83% of the total emissions.

V.B Maximum Achievable Control Technology (MACT)

Section 112 of the Clean Air Act (42 U.S.C. § 7412) requires that any major stationary source that emits or has the potential to emit 10 tons per year or more of any single hazardous air pollutant ("HAP"), or 25 tons or more per year of any combination of hazardous air pollutants, utilize the maximum achievable control technology ("MACT") to control the emissions. (42 U.S.C. § 7412(d).) The Siting Application suggests that emissions of all Section 112(b) HAPs would be less than 10 ton/yr for any single HAP and 25 ton/yr for any combination of HAPs.

The revised emissions in Table 7 demonstrate that this is incorrect. Formaldehyde emissions alone are 13.5 ton/yr per turbine or 54 ton/yr for the four turbines. Of this amount, 92% occurs during startup. The total HAP emissions are 16.3 ton/yr from each turbine or 65.2 ton/yr from both turbines. Therefore, the HAP emissions exceed both the 10 ton/yr single HAP MACT standard and the 25 ton/yr combined HAP MACT standard. This requires that a MACT analysis be prepared and additional controls imposed to limit HAP emissions below the standards.

There are currently no source category MACT standards for combustion turbines. However, EPA published an Interpretive Rule on May 25, 2000,[31] clarifying that case-by-case MACT analyses under 40 CFR 63, Subpart B, are required for major stationary source combustion turbines such as this project. Further, AAC R18-2-302(D) states that "[i]f MACT has not been established by the Administrator, such determination shall be made on a case-by-case basis

[31] National Emission Standards for Hazardous Air Pollutants for Source Categories, Federal Register, v. 65, no. 102, May 25, 2000.

pursuant to 40 CFR 63.40 through 63.44, as incorporated by reference in R18-2-1101(B)." Therefore, a case-by-case MACT analysis is required.

Several methods can be used to further control HAP emissions. The efficiency of the oxidation catalyst could be increased from the proposed 80% to 95%. The proposed auxiliary boiler would be used to keep the HRSG hot during shutdowns. (Siting Application, p. B-1-23.) The firing rate of this boiler could be increased so that it could be used to preheat the oxidation catalyst to its optimum operating temperature prior to lightoff. The number of startups could be reduced.

LIST OF EXHIBITS

1. Letter from Gerardo Rios, EPA, to David Dixon, SLOAPCD, 6/19/01
2. Draft Approval of the Prevention of Significant Deterioration and Notice of Construction, Sumas Energy 2
3. Final Determination of Compliance for Duke Energy, Morro Bay, 8/30/01
4. ANP Blackstone Energy Project permit
5. Cogentrix Energy Inc., ammonia slip source tests
6. Final Report, 1997 Emission Compliance Tests at the Crockett Cogeneration Facility
7. Fax from John Calvello, Hitachi America, to Phyllis Fox, 8/13/98
8. Letter from Steven C. Riva, EPA, to Robert L. Ewing, NYSDEC, 9/27/00
9. CARB, BACT determinations for boilers
10. SCAQMD, BACT determinations for boilers
11. Coen Company Inc., Industrial Low NOx Burner Sales & Installation List
12. Radian/TODD Rapid Mix Burner Ultra Low NOx Installations
13. U.S. Borax, Emission Performance Testing of One Boiler, 12/21/95
14. SJVAPCD, BACT NOx Controls for Natural Gas-fired Boilers, Process Heaters, and Steam Generators
15. Final Report, 1997 Emission Compliance Tests at the Crockett Cogeneration Facility
16. Mojave Desert AQMD, Permit to Operate, Federal Bureau of Prisons
17. Gas Turbine World, Low-temperature SCR Expedites Plant Retrofits for NOx Reduction
18. Engelhard, Experience List: CO Oxidation Catalysts on Gas Turbines
19. Commonwealth of Massachusetts, Lane Construction Corporation permit
20. State of Rhode Island, Block Island Power Company minor source permit
21. Great Basin UAPCD, Mountain Utilities permit to operate
22. Eldorado Energy, authority to construct/operating permit
23. State of Vermont DEC, Okemo Mountain, Inc., permit to operate
24. Great Basin UAPCD, CR Briggs Corporation permit to operate
25. Steuler, DeNOx Systems reference list
26. Vendor lists
27. Johnson Matthey, Catalytic Systems Division
28. Engelhard, SCR Systems for NOx Control – Diesel and Natural Gas Engines
29. Heck & Farrauto, Catalytic Air Pollution Control: Commercial Technology
30. Engelhard, oxidation catalyst budgetary quotes
31. EPRI/GRI, Gas-Fired Boiler and Turbine Air Toxics Summary Report, August 1996
32. Westinghouse, combined cycle plant startup curves
33. Engelhard, Camet Oxidation Catalyst, Typical Performance

34. Emission Test Report for Frontera Generation Facility, May 2000

35. Emission Test Report for Frontera Generation Facility, July 1999

36. Source Emissions Survey of Pasadena II Power Facility, September and October 1999

37. Summary of source test results for "Alley Oop" power plant

38. Summary of source test results for "Blondie" power plant

39. Summary of source test results for "Bugs" power plant

40. Emission tests at Sacramento Cogeneration Facility, HRSG-A, March 1998

41. Emission tests at Sacramento Cogeneration Facility, HRSG-B, March 1998

River Road

Note: A zero CO value means that the facility was operating.
Missing values are startups/shutdowns/exceedances.

TimeStamp	CO15pctV	CO 3-hr
10/1/98 0:00		
10/1/98 1:00		
10/1/98 2:00		
10/1/98 3:00		
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10/1/98 5:00		
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12/31/98 17:00	0.168571	0.168571

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1/2/99 6:00	0.081944	0.081944
1/2/99 7:00	0.163889	0.109259
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1/3/99 3:00	0.163889	0.163889
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9/27/99 0:00	0	0
9/27/99 1:00	0	0
9/27/99 2:00	0	0
9/27/99 3:00	0	0
9/27/99 4:00	0	0
9/27/99 5:00	0	0
9/27/99 6:00	0	0
9/27/99 7:00	0	0
9/27/99 8:00	0	0
9/27/99 9:00	0	0
9/27/99 10:00	0	0
9/27/99 11:00	0	0
9/27/99 12:00	0	0
9/27/99 13:00	0	0
9/27/99 14:00	0	0
9/27/99 15:00	0	0
9/27/99 16:00	0	0
9/27/99 17:00	0	0
9/27/99 18:00	0	0
9/27/99 19:00	0	0
9/27/99 20:00	0	0
9/27/99 21:00	0	0
9/27/99 22:00	0	0
9/27/99 23:00	0	0
9/28/99 0:00	0	0
9/28/99 1:00	0	0
9/28/99 2:00	0	0
9/28/99 3:00	0	0
9/28/99 4:00	0	0
9/28/99 5:00	0	0
9/28/99 6:00	0	0
9/28/99 7:00	0	0
9/28/99 8:00	0	0
9/28/99 9:00	0	0
9/28/99 10:00	0	0
9/28/99 11:00	0	0
9/28/99 12:00	0	0
9/28/99 13:00	0	0

9/28/99 14:00	0	0
9/28/99 15:00	0	0
9/28/99 16:00	0	0
9/28/99 17:00	0	0
9/28/99 18:00	0	0
9/28/99 19:00	0	0
9/28/99 20:00	0	0
9/28/99 21:00	0	0
9/28/99 22:00	0	0
9/28/99 23:00	0	0
9/29/99 0:00	0	0
9/29/99 1:00	0	0
9/29/99 2:00	0	0
9/29/99 3:00	0	0
9/29/99 4:00	0	0
9/29/99 5:00	0	0
9/29/99 6:00	0	0
9/29/99 7:00	0	0
9/29/99 8:00	0	0
9/29/99 9:00	0	0
9/29/99 10:00	0	0
9/29/99 11:00	0	0
9/29/99 12:00	0	0
9/29/99 13:00	0	0
9/29/99 14:00	0	0
9/29/99 15:00	0	0
9/29/99 16:00	0	0
9/29/99 17:00	0	0
9/29/99 18:00	0	0
9/29/99 19:00	0	0
9/29/99 20:00	0	0
9/29/99 21:00	0	0
9/29/99 22:00	0	0
9/29/99 23:00	0	0
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9/30/99 3:00	0	0
9/30/99 4:00	0	0
9/30/99 5:00	0	0
9/30/99 6:00	0	0
9/30/99 7:00	0	0
9/30/99 8:00	0	0
9/30/99 9:00	0	0
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9/30/99 12:00	0	0
9/30/99 13:00	0	0
9/30/99 14:00	0	0
9/30/99 15:00	0	0
9/30/99 16:00	0	0
9/30/99 17:00	0	0

9/30/99 18:00	0	0
9/30/99 19:00	0	0
9/30/99 20:00	0	0
9/30/99 21:00	0	0
9/30/99 22:00	0	0
9/30/99 23:00	0	0

FIGURE 1
River Road Generating Plant, 1-hr Rolling Average CO

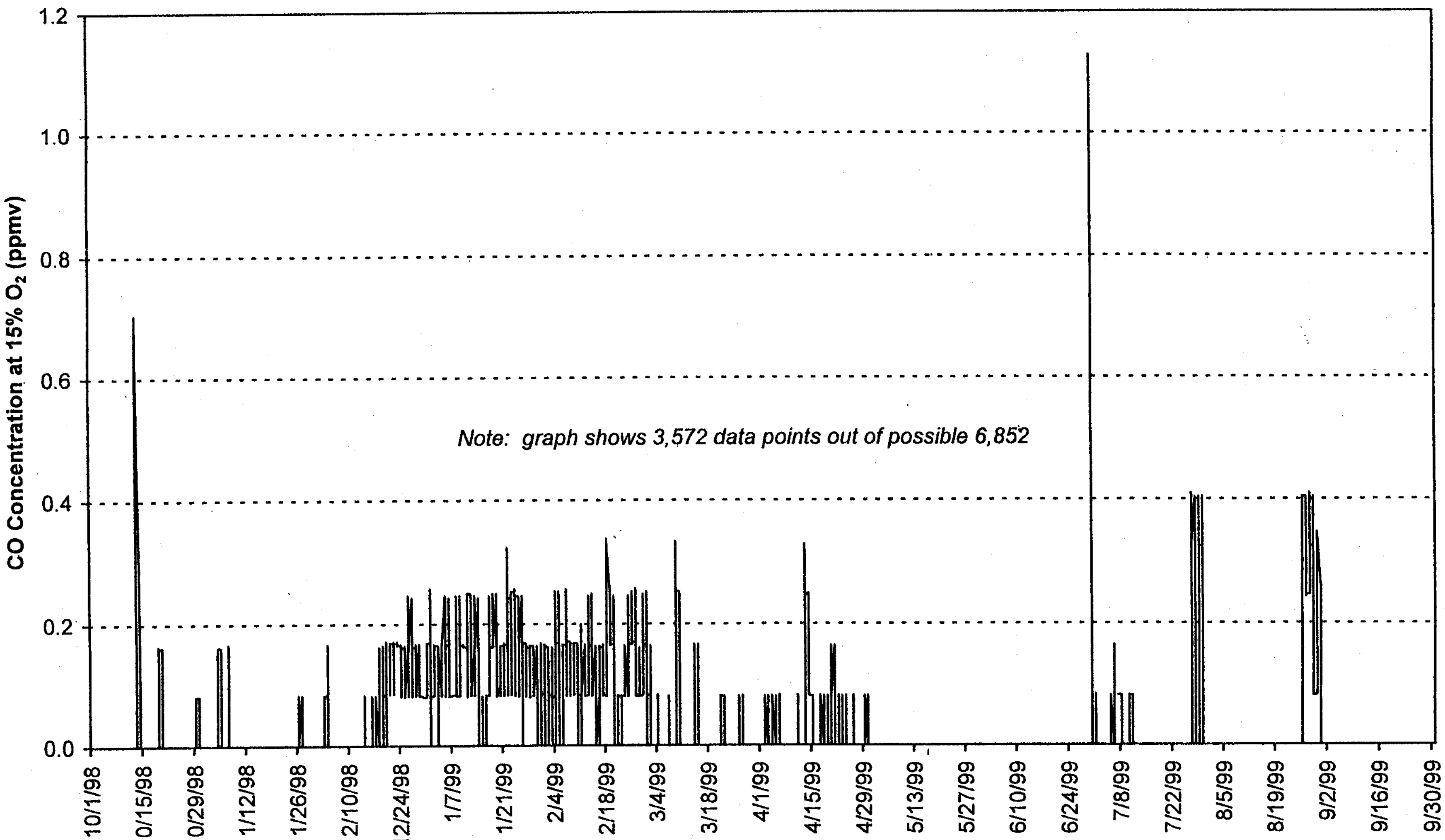

FIGURE 2
River Road Generating Plant, 3-hr Rolling Average CO

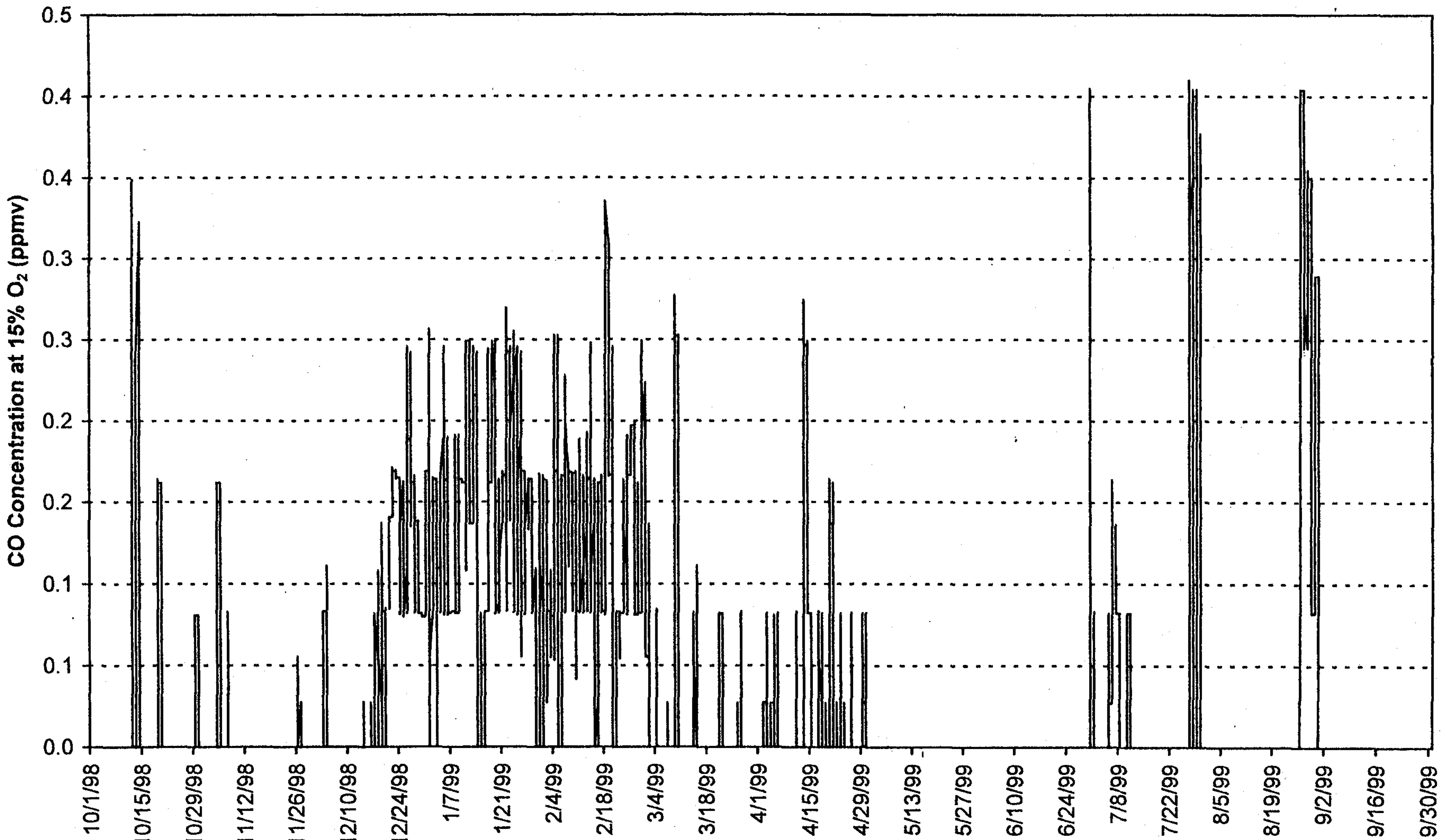

Figure 3. Turbine Carbon Monoxide Emission Factor versus Load (GRI/EPRI 8/96)

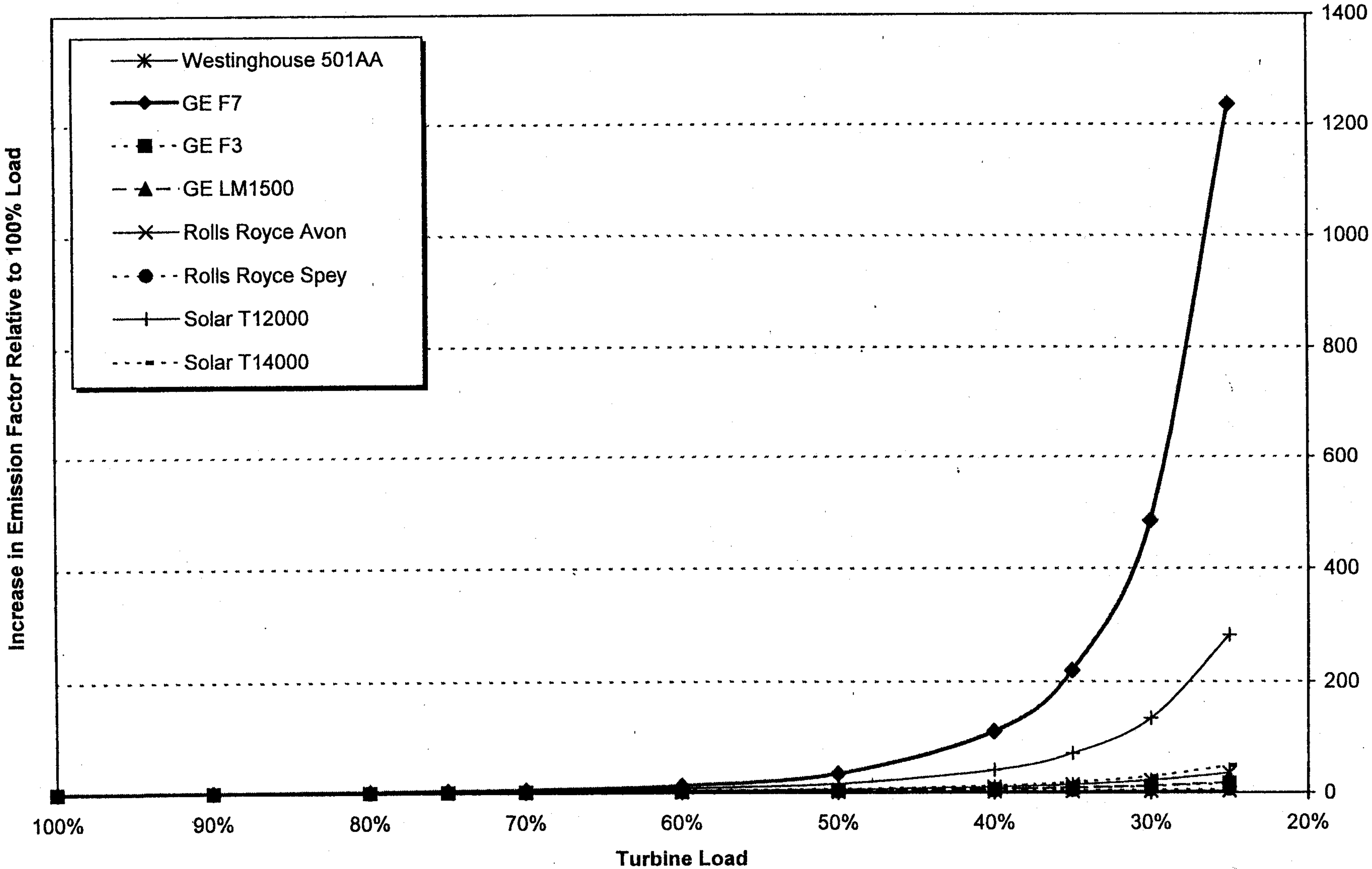

Figure 4. Turbine Non-Methane Hydrocarbon Emission Factor versus Load (GRI/EPRI 8/96)

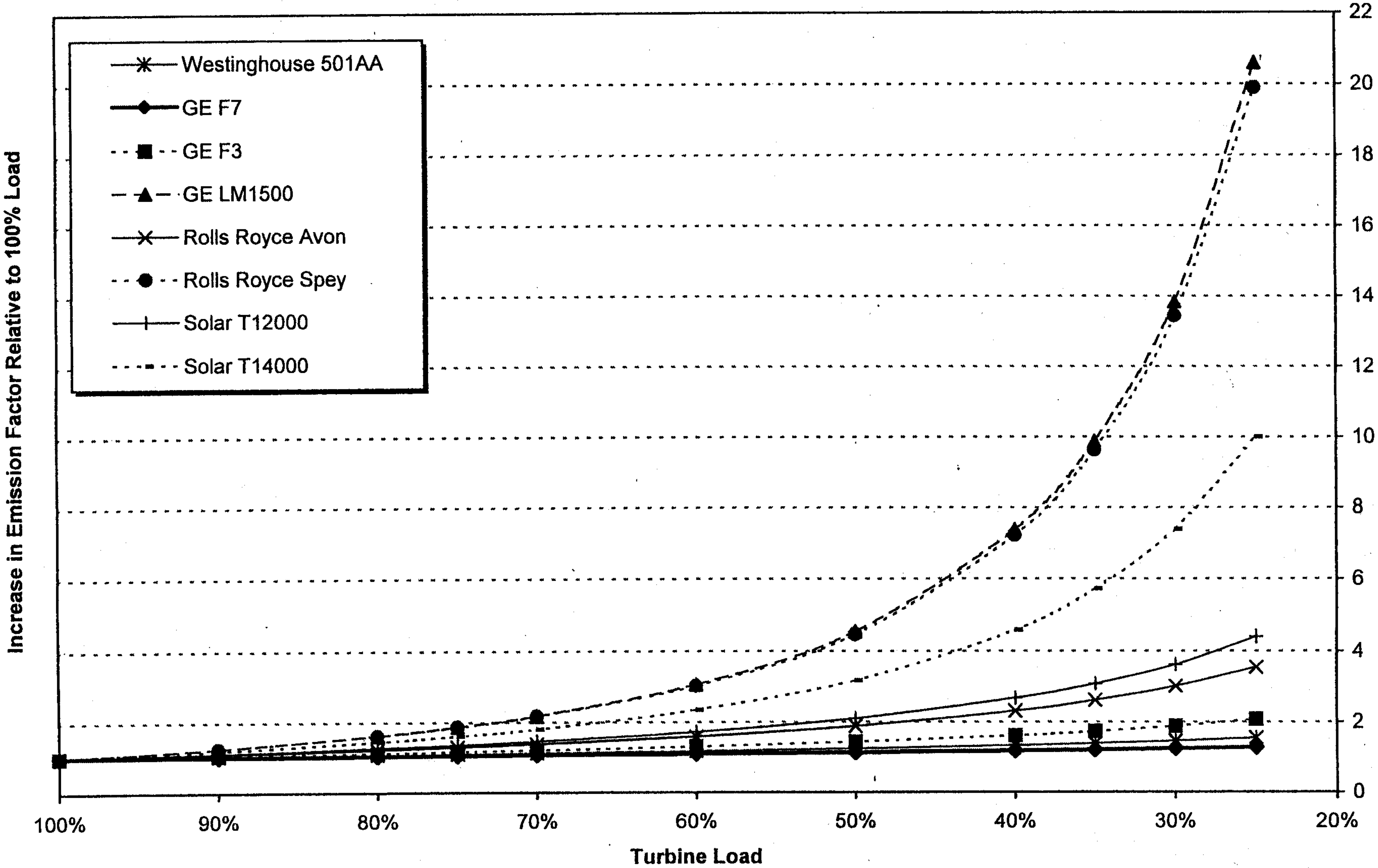

Figure 5. Turbine Formaldehyde Emission Factor versus Load (GRI/EPRI 8/96)

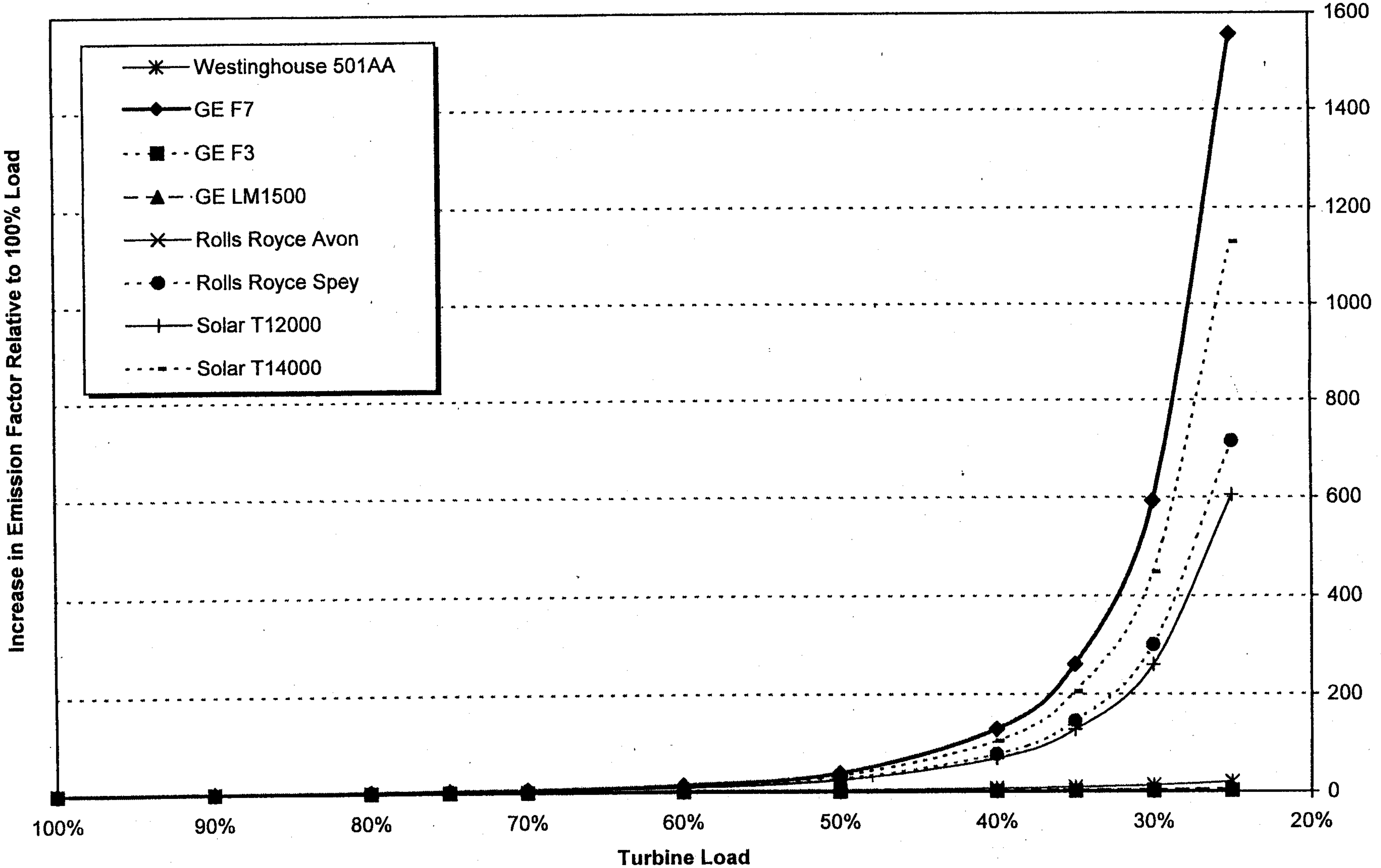

Figure 6. Turbine Benzene Emission Factor versus Load (GRI/EPRI 8/96)

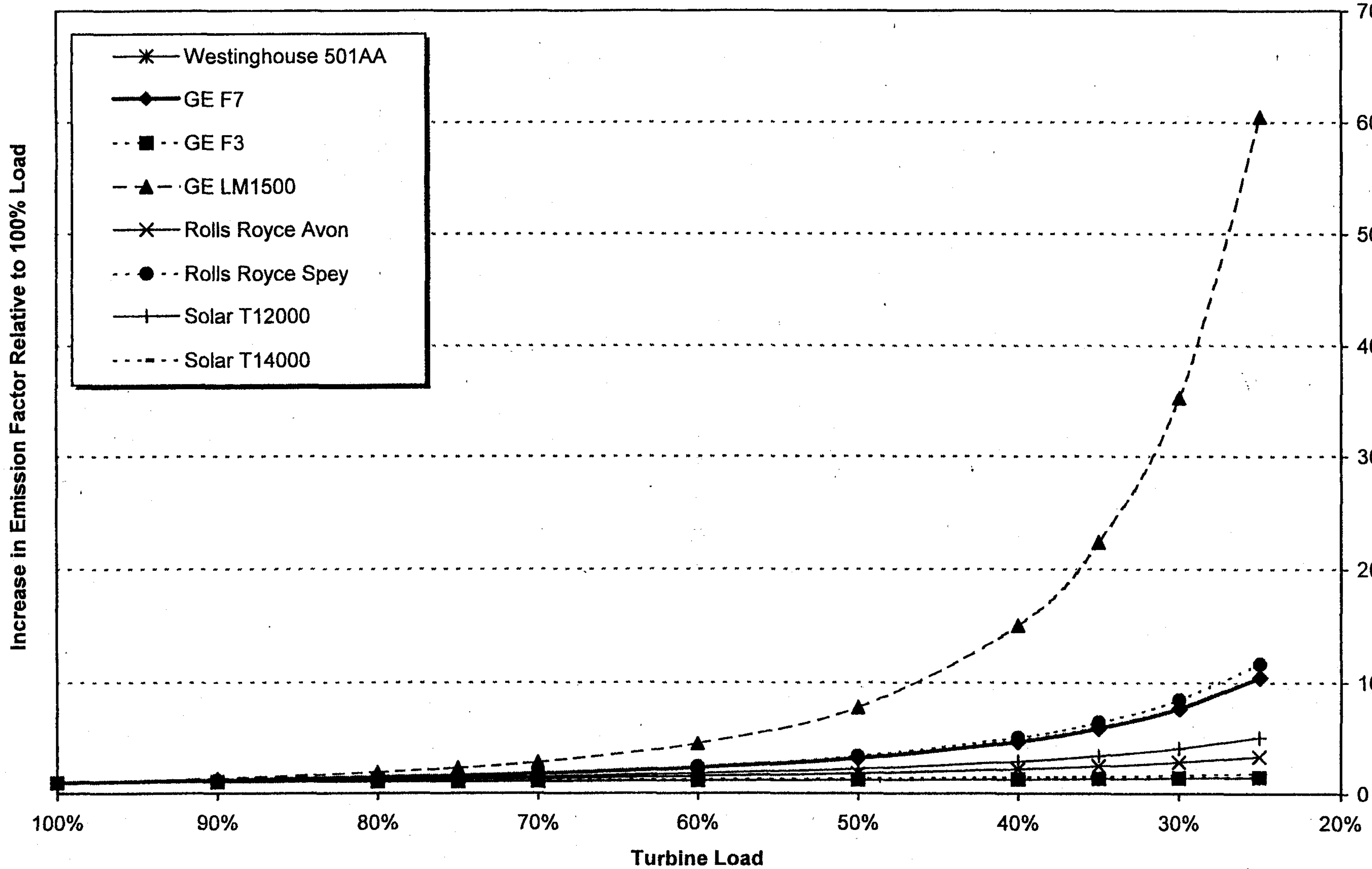

Figure 7. Aircraft Turbine Emission Factor versus Load (FAA Database)

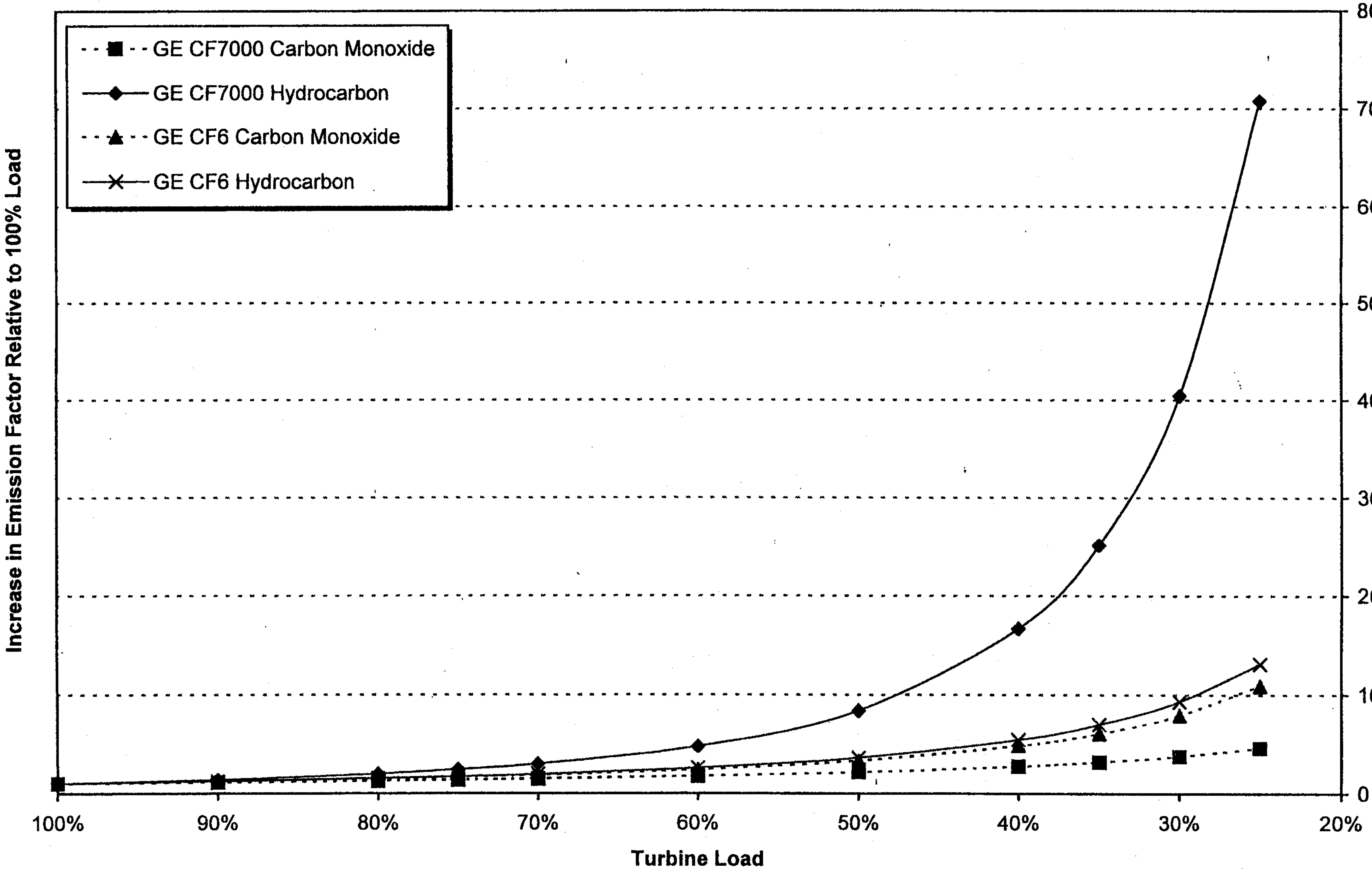

TABLE 1
NOx Limits for Combined-Cycle Turbine Projects

State	Permit Date	Facility	# of CTs	Turbine Model	Mode	NOx Limit	NOx Avg. Time	NOx Control Method	NOx BACT/ LAER
MA	draft permit 9/01	IDC Bellingham (525 MW)	2	GE 7FA	CC	1.5 ppm	1-hr	DLN/ SCR	LAER
CA	final permit 9/00	Otay Mesa (510 MW)	2	GE 7FA or SW 501F or ABB GT-24	SI CC	2 ppm (1ppm goal)	3-hr (24-hr goal)	DLN w/ SCR or SCONOx	LAER
CT	final permit 12/98	PDC-El Paso Milford LLC (540 MW)	2	ABB GT-24	CC	2.0 ppm	3-hr	SCR	LAER
CT	final permit 12/99	Lake Road Generating (792 MW)	2	ABB GT-24	CC	2.0 ppm	3-hr	SCR	LAER
MA	operating	ANP Bellingham (580 MW)	2	ABB GT-24	CC	2.0 ppm	1-hr	SCR	LAER
MA	final permit 7/99	ANP Blackstone (580 MW)	2	ABB GT-24	SI CC	2.0 ppm	1-hr	SCR	LAER
MA	final permit 1/00	Sithe Mystic Development (1500 MW)	2	Mitsubishi 501G	DF CC	2.0 ppm	1-hr	SCR	LAER
MA	final permit 2/00	Cabot Power (350 MW)	1	SW 501G	CC	2.0 ppm	1-hr	SCR	LAER
MA	3/00	Fore River Station (775 MW)	2	Mitsubishi 501G	CC	2.0 ppm	1-hr	DLN/ SCR	LAER
ME	final permit 4/99	Gorham Energy (500 MW)	3	ABB GT-24	CC	2.0 ppm	1-hr	DLN/ SCR	LAER
WA	draft permit 2/01	Sumas	2	GE 7FA	DF CC	2.0 ppm	1-hr	DLN/ SCR	BACT
CA	final permit 12/00	Western Midway-Sunset	2	GE 7FA or SW 501F	-	2.0 ppm	1-hr	DLN/ SCR	LAER
CT	5/01	Towantic Co.	2	GE 7FA	-	2.0 ppm	1-hr	DLN/ SCR	LAER
CA	final permit 8/01	Morro Bay (600 MW)	2	GE 7FA	DF CC	2.0 ppm	1-hr	DLN/ SCR	BACT

SW = Siemens-Westinghouse
DF = duct firing
SI = steam injection
DLN = dry low NOx combustor
CC = combined cycle

TABLE 2
CO Limits for Combined-Cycle Turbine Projects

State	Permit Date	Facility	# of CTs	Turbine Model	Mode	CO Limit	CO Avg. Time	CO Control Method	CO BACT/ LAER
CA	final permit 8/01	Morro Bay (600 MW)	2	GE 7FA	DF CC	2.0 ppm	3-hr	CalOx	BACT
MA	final permit 1/00	Sithe Mystic Development (1550 MW)	2	Mitsubishi 501G	DF CC	2 ppm	1-hr	CalOx	BACT
MA	final permit 1/00	Cabot Power (350 MW)	1	SW 501G	CC	2 ppm	1-hr	CalOx	BACT
CT	final permit 12/98	PDC-El Paso Milford LLC (540 MW)	2	ABB GT-24	CC	2.0 ppm	1-hr	CalOx	BACT
MA	3/00	Fore River Station (775 MW)	2	Mitsubishi 501G	CC	2.0 ppm	1-hr	CalOx	BACT
MA	12/99	IDC Bellingham (525 MW)	2	GE 7FA	-	2.0 ppm	1-hr	CalOx	BACT
WA	draft permit 2/01	Sumas	2	GE 7FA	DF CC	2.0 ppm	1-hr	CalOx	BACT
NJ	permit modification under review	Mantua Creek Generating (911 MW)	3	GE 7FB	CC	2.34 ppm	1-hr	CalOx	BACT
MA	final permit 1/00	ANP Bellingham (580 MW)	2	ABB GT-24	CC	3 ppm	1-hr	CalOx	BACT
MA	final permit 9/99	ANP Blackstone (580 MW)	2	ABB GT-24	SI CC	3 ppm	1-hr	CalOx	BACT
CT	final permit 12/99	Lake Road Generating (792 MW)	2	ABB GT-24	CC	3.0 ppm	1-hr	CalOx	BACT
MA	draft permit 7/97	Berkshire Power (272 MW)	1	ABB GT-24	CC	4 ppm	1-hr	CalOx	BACT
MA	draft permit 10/97	Dighton Power (170 MW)	1	ABB GT-11N2	CC	4 ppm	1-hr	CalOx	BACT
MA	final permit 3/00	Millennium Power (360 MW)	1	SW 501G	CC	4 ppm	1-hr	CalOx	BACT

						CO			
State	Permit Date	Facility	# of CTs	Turbine Model	Mode	Limit	Avg. Time	Control Method	BACT/ LAER
CA	final permit 6/00	Three Mountain Power (340 MW)	2	GE F7	DF CC	4.0 ppm	3-hr	CalOx	BACT
CA	startup 8/01	Sutter Power Project (360 MW)	2	SW 501F	DF CC	4.0 ppm	24-hr	CalOx	BACT
CA	final permit 5/00	High Desert (720 MW)	2	GE 7FA or SW 501F	DF CC	4.0 ppm	24-hr	CalOx	BACT
CA	final permit 12/00	Elk Hills (500 MW)	2	GE 7FA	-	4.0 ppm	3-hr	CalOx	BACT

SW = Siemens-Westinghouse
DF = duct firing
SI = steam injection
GCP = good combustion practices
CalOx = oxidation catalyst
CC = combined cycle

TABLE 3
VOC Source Test Results for Large (>160 MW) GE Frame 7 Gas Turbines

Facility and Gas Turbine Description	Method of Control	Permit Limit	Load	SOURCE TEST RESULTS Emissions (lb/hr)	SOURCE TEST RESULTS Concentration (ppm @ 15% O_2)	Date
River Road Generating Project 248-MW GE 7231 FA gas turbine	Engelhard oxidation catalyst	6.6 lb/hr	100%	0.0*	0.0*	10/97
Ingleside Cogen (Duke) 2 170-MW GE Frame 7EA turbines with duct burners	DLN					
Turbine 1		1.51 ppm	25%	0.004	0.5	8/99
			50%	0.003	0.4	8/99
			75%	0.001	0.1	8/99
			100%	0.003	0.203	8/99
Turbine 1 and duct burner		5.6 ppm	100%	1.23	0.5	8/99
Turbine 2		1.51 ppm	25%	0.002	0.22	9/99
			50%	0.003	0.27	9/99
			75%	0.003	0.30	9/99
			100%	0.003	0.273	9/99
Turbine 2 and duct burner		5.6 ppm	100%	1.73	0.6	9/99
Frontera Generation (Duke) 2 165-MW GE Frame 7EA turbines	DLN					
Turbine 1		0.6 lb/hr	25-100%	0.00 - 0.002	0.00	5/00
Turbine 2		0.6 lb/hr	25-100%	0.00 - 0.011	0.00 - 0.01	3/00
Pasadena Power Facility 1 160-MW Westinghouse 501FA	DLN, SCR					
Power Augmentation On			100%	< 0.57*	< 0.01*	9/99
Power Augmentation Off			100%		0.1*	9/99
Power Augmentation Off			70%		0.1*	9/99
Power Augmentation Off			60%		< 0.1*	9/99
Crockett Cogen 1 160-MW GE 7FA w/ 349 MMBtu/hr duct burner	DLN, SCR, Camet oxidation catalyst	2.8 lb/hr	100%	< 0.02	0.0068	6/97
			100%	0.116	0.041	6/98

* Total Hydrocarbons

TABLE 4
NOx, CO, and PM10 Permit Limits for Some Diesel Engines

Company/ Project	Location	Engine	Control	Permit Date	Emission Limit (g/bhp-hr) NOx	CO	PM10	Exhibit No.
Lane Construction Corp.	MA	1220-hp Caterpillar diesel generator	SCR	8/96	0.55	0.05	-	19
Block Island Power	RI	Caterpillar 1648-hp diesel generator	SCR	2/01	0.65	3.42	0.13	20
		Caterpillar 2336-hp diesel generator	SCR	2/01	0.65	3.42	0.13	
Kirkwood Resort	CA	6 Caterpillar diesel generators, 853-1195 hp	SCR	12/98	0.9	-	-	21
Kiewit Companies	NV	3 Caterpillar 537-hp diesel generators	SCR	3/99	1.23	0.50	0.076	22
LA Times	CA	2340-hp Detroit diesel generator	SCR	8/89	1.5			
Okemo Mountain	VT	2-MW Caterpillar 3516 diesel generator	SCR	9/00	1.6	0.6	0.04	23
CR Briggs	CA	4 Caterpillar 1600-hp diesel generators	SCR	6/97	1.9	-	-	24

TABLE 5

Fraction of Fuel Sulfur Converted to Sulfuric Acid Mist[a]

Facility	Test Date	Turbine	Size MW	Duct Burners	Fuel	Controls	Percent Conversion H_2SO_4 (%)	Exhibit No.
Frontera Unit 1	5/00	GE 7FA	165	No	NG	DLN	100	34
Unit 2	5/00	GE 7FA	165	No	NG	DLN	20.5	34
Unit 2	7/99	GE 7FA	165	No	NG	DLN	100	35
Pasadena	10/99	W501FA	160	No	NG	DLN, SCR	24.2	36
"Alley Oop"[b] Unit 1	4/00	GE7FA	167.8	No	Oil	WI	48.2	37
Unit 2	4/00	GE7FA	167.8	No	Oil	WI	20.6	37
Unit 1	5/00	GE7FA	167.8	No	NG	DLN	76.0	37
Unit 2	5/00	GE7FA	167.8	No	NG	DLN	97.5	37
"Blondie"[b]	9/97	W501F	171.5	Yes	NG	DLN, SCR, OC	13.4	38
	9/97	W501F	171.5	Yes	Oil	WI, SCR, OC	18.1	38
"Bugs"[b]	7/97	W501F	171.5	No	Oil	WI, SCR	3.4	39
Sacramento Cogeneration Authority								
Turbine A	3/98	LM6000 PA	44	Yes	NG	WI, SCR, OC	92.6	40
Turbine B	3/98	LM6000 PA	44	Yes	NG	WI, SCR, OC	92.8	41
Average SAM:							54.4	

a DLN = dry low NOx combustor; NG = natural gas; OC = oxidation catalyst; SCR = selective catalytic reduction; WI = water injection.

b Confidential source test data (names and locations of power plants redacted) introduced by GE in the Towantic power plant licensing proceedings before the Connecticut Department of Environmental Management, 2001.

TABLE 6
Uncontrolled Turbine Emission Factors (lb/MMBtu)

Pollutant	Startup Scaling Factor[a]	Gas 100% Load Uncontrolled[b]	Gas Startup Uncontrolled[c]
		A	B
Organics			
1,3-Butadiene	1.4	4.29E-07	6.01E-07
Acetaldehyde	502.6	4.02E-05	2.02E-02
Acrolein	502.6	6.36E-05	3.20E-02
Benzene	7.6	1.18E-05	8.97E-05
Ethylbenzene	1.4	3.20E-05	4.48E-05
Formaldehyde	502.6	7.09E-04	3.56E-01
Hexane	1.4	2.54E-04	3.56E-04
Naphthalene	1.4	1.27E-06	1.78E-06
PAH	1.4	2.23E-06	3.12E-06
Propylene Oxide	1.4	2.86E-05	4.00E-05
Toluene	9.8	1.30E-04	1.27E-03
Xylenes	1.4	6.40E-05	8.96E-05

a Ratio of emission factor at 30% load to 100% load for GRI/EPRI (1996), Table S-2.

b AP-42, Table 3.1-3 and Siting App., Appx. H. for HAPs.

c Gas startup factor = scaling factor x 100% load emission factor.

TABLE 7
Turbine Emissions (ton/yr per turbine)

Pollutant	NATURAL GAS							TOTAL
	Cold Starts		Warm Starts		Hot Starts		100% Load	
	Uncontrolled[a]	Controlled[b]	Uncontrolled[c]	Controlled[d]	Uncontrolled[e]	Controlled[f]	Controlled[g]	
Organics								
1,3-Butadiene	2.87E-06	7.58E-06	1.43E-06	5.02E-06	7.17E-07	3.18E-06	6.78E-04	6.99E-04
Acetaldehyde	9.65E-02	2.55E-01	4.83E-02	1.69E-01	2.41E-02	1.07E-01	6.36E-02	7.63E-01
Acrolein	1.53E-01	4.04E-01	7.64E-02	2.68E-01	3.82E-02	1.70E-01	1.01E-01	1.21E+00
Benzene	4.28E-04	1.13E-03	2.14E-04	7.50E-04	1.07E-04	4.76E-04	1.87E-02	2.18E-02
Ethylbenzene	2.14E-04	5.65E-04	1.07E-04	3.75E-04	5.35E-05	2.38E-04	5.06E-02	5.21E-02
Formaldehyde	1.70E+00	4.49E+00	8.51E-01	2.98E+00	4.26E-01	1.89E+00	1.12E+00	1.35E+01
Hexane	1.70E-03	4.49E-03	8.49E-04	2.97E-03	4.25E-04	1.89E-03	4.02E-01	4.14E-01
Naphthalene	8.49E-06	2.24E-05	4.25E-06	1.49E-05	2.12E-06	9.43E-06	2.01E-03	2.07E-03
PAH	1.49E-05	1.97E-04	7.46E-06	2.61E-05	1.86E-05	8.28E-05	1.76E-02	1.80E-02
Propylene Oxide	9.56E-04	5.05E-04	9.56E-05	3.35E-04	4.78E-05	2.12E-04	4.52E-02	4.74E-02
Toluene	6.09E-03	1.61E-02	3.04E-03	1.07E-02	1.52E-03	6.76E-03	2.06E-01	2.50E-01
Xylenes	4.28E-04	1.13E-03	2.14E-04	7.49E-04	1.07E-04	4.75E-04	1.01E-01	1.04E-01
Total (tons/yr)	**1.96**	**5.18**	**0.98**	**3.43**	**0.49**	**2.18**	**2.13**	**16.35**

Notes:

Emissions are estimated as follows: EF x firing rate x hours in mode x adjustment to firing rate x (1 - control efficiency). EF is emission factor from Table 4. Firing rate is from Class I Permit Application, Table 5.2. Hours in mode assumes 50 4.73-hr cold starts, 50 3.08-hr warm starts, 50 1.93-hr hot starts, and 8272.5 hrs at 100% load. No control during first 20 min for cold starts, 10 min for warm starts, and 5 min for hot starts. Firing rate is assumed proportional to average load during startup and thus is adjusted to 30% of peak. Control efficiency assumed to be 80% for all VOCs (Heck and Farruto 1995, Table 11.1).

a Cold Start Uncontrolled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 16.67 hr/yr x 0.30]/2000 lb/ton.

b Cold Start Controlled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 220.0 hr/yr x 0.30 x (1-0.8)]/2000 lb/ton.

c Warm Start Uncontrolled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 8.33 hr/yr x 0.30]/2000 lb/ton.

d Warm Start Controlled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 145.83 hr/yr x 0.30 x (1-0.8)]/2000 lb/ton.

e Hot Start Uncontrolled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 4.17 hr/yr x 0.30]/2000 lb/ton.

f Hot Start Controlled Gas Emissions (ton/yr) = [EF_B x 1911 MMBtu/hr x 92.5 hr/yr x 0.30 x (1-0.8)]/2000 lb/ton.

g 100% Load Gas Controlled Emissions (ton/yr) = [EF_A x 1911 MMBtu/hr x 8272.5 hr/yr x (1-0.8)]/2000 lb/ton.

Carbon Monoxide (lb/10^6 BTU)

Turbine	W501AA				W501F	
MW	55				150	
MMBtu/hr	789				1600	
Load						
100.0%	0.005	6.30E-03	1.00	4.97	0.019264967	2.09E-02
90.0%		8.27E-03	1.31	5.87		2.10E-02
80.0%	0.012	1.12E-02	1.78	7.08		2.11E-02
75.0%		1.32E-02	2.10	7.84		2.11E-02
70.0%		1.58E-02	2.51	8.74	0.026332538	2.12E-02
60.0%		2.36E-02	3.74	11.16		2.13E-02
50.0%	0.055	3.78E-02	6.00	14.90	0.02811177	2.15E-02
40.0%		6.72E-02	10.67	21.22		2.17E-02
35.0%		9.49E-02	15.07	26.21		2.18E-02
30.0%	0.111	1.41E-01	22.44	33.46		2.19E-02
25.0%		2.26E-01	35.94	44.66	0.034405719	2.20E-02
		y = 0.0063x-2.5838		8.985507567		y = 0.0209x-0.38

GE F7				GE F3		
	150				7.7	
	1624				87	
1.00	0.002	1.30E-03	1.00	1.03	0.004	5.20E-03
1.00		2.23E-03	1.72	1.59		6.46E-03
1.01		4.09E-03	3.15	2.58		8.23E-03
1.01		5.70E-03	4.38	3.37	0.015	9.40E-03
1.01	0.002	8.12E-03	6.25	4.49		1.08E-02
1.02	0.053	1.79E-02	13.79	8.49		1.49E-02
1.03		4.57E-02	35.18	18.04	0.018	2.16E-02
1.04		1.44E-01	110.67	45.40		3.42E-02
1.04		2.86E-01	219.73	78.88		4.51E-02
1.05	0.635	6.31E-01	485.03	149.25		6.19E-02
1.05		1.61E+00	1237.32	317.28		9.00E-02
86		y = 0.0013x-5.1365		309.3293679		y = 0.0052x-2.05

	GE LM1500			RR Avon			
		10.6			10.7		
		145			158		
	1.00	0.158	1.97E-01	1.00	0.41	3.93E-01	1.00
	1.24		2.46E-01	1.25		4.30E-01	1.09
	1.58		3.16E-01	1.60		4.75E-01	1.21
	1.81	0.505	3.62E-01	1.83	0.483	5.01E-01	1.28
	2.08		4.18E-01	2.12		5.32E-01	1.35
	2.86		5.79E-01	2.94		6.06E-01	1.54
	4.16	0.782	8.51E-01	4.31	0.689	7.07E-01	1.80
	6.59		1.36E+00	6.90		8.55E-01	2.18
	8.67		1.80E+00	9.14		9.57E-01	2.44
	11.90		2.50E+00	12.66		1.09E+00	2.78
	17.32	3.569	3.67E+00	18.59	1.3	1.27E+00	3.24
57			y = 0.1973x-2.1081			y = 0.3929x-0.8482	

RR Spey			Solar T12000			Solar T14000
12.2			9.4			10.9
132			100			110
0.133	1.89E-01	1.00	0.006	5.20E-03	1.00	0.005
	2.17E-01	1.15		7.98E-03	1.54	
	2.53E-01	1.34		1.29E-02	2.48	
0.339	2.75E-01	1.45	0.01	1.68E-02	3.22	0.007
	3.00E-01	1.59		2.22E-02	4.27	
	3.67E-01	1.94		4.16E-02	7.99	
0.674	4.65E-01	2.45	0.146	8.73E-02	16.79	0.022
	6.20E-01	3.28		2.16E-01	41.63	
	7.37E-01	3.90		3.73E-01	71.68	
	9.00E-01	4.76		6.98E-01	134.22	
0.906	1.14E+00	6.02	1.253	1.47E+00	281.85	0.22

y = 0.1893x-1.2953

y = 0.0052x-4.0694

Solar LoNOx

		10.9		
		110		
3.80E-03	1.00	0.015	9.70E-03	1.00
5.11E-03	1.35		1.31E-02	1.35
7.13E-03	1.88		1.82E-02	1.88
8.55E-03	2.25	0.038	2.18E-02	2.25
1.04E-02	2.73		2.65E-02	2.73
1.60E-02	4.22		4.09E-02	4.22
2.68E-02	7.05	0.141	6.84E-02	7.05
5.02E-02	13.22		1.28E-01	13.22
7.32E-02	19.25	4.898	1.87E-01	19.25
1.13E-01	29.72		2.88E-01	29.72
1.89E-01	49.67		4.82E-01	49.67

$y = 0.0038x-2.8172$

$y = 0.0097x-5.2793$

TGNMO ($lb/10^6$ BTU)

Turbine	W501AA			GE F7		
MW	55			150		
MMBtu/hr	789			1624		
Load						
100.0%	0.010001	1.04E-02	1.00	0.007866	8.90E-03	1.00
90.0%		1.08E-02	1.03		9.07E-03	1.02
80.0%	0.012761	1.12E-02	1.07		9.26E-03	1.04
75.0%		1.14E-02	1.10		9.37E-03	1.05
70.0%		1.16E-02	1.12	0.012763	9.49E-03	1.07
60.0%		1.22E-02	1.18	0.008323	9.75E-03	1.10
50.0%	0.011182	1.30E-02	1.25		1.01E-02	1.13
40.0%		1.39E-02	1.34		1.05E-02	1.18
35.0%		1.45E-02	1.39		1.07E-02	1.21
30.0%	0.01627	1.52E-02	1.46	0.010765	1.10E-02	1.24
25.0%		1.61E-02	1.55		1.14E-02	1.28
		y = 0.0104x-0.317			y = 0.0089x-0.1789	

GE F3			GE LM1500			RR Avon
7.7			10.6			10.7
87			145			158
0.00764	7.60E-03	1.00	0.0133	1.33E-02	1.00	0.0311
	8.03E-03	1.06		1.67E-02	1.26	
	8.55E-03	1.12		2.16E-02	1.63	
	8.84E-03	1.16		2.49E-02	1.87	
	9.17E-03	1.21		2.90E-02	2.18	
	9.94E-03	1.31		4.06E-02	3.05	
0.011	1.09E-02	1.44		6.04E-02	4.54	
	1.23E-02	1.62		9.82E-02	7.39	
	1.32E-02	1.74		1.31E-01	9.89	
	1.43E-02	1.88		1.84E-01	13.84	
	1.58E-02	2.07	0.274	2.74E-01	20.60	0.11
	y = 0.0076x-0.5259			y = 0.0133x-2.1823		

TGNMO ($lb/10^6$ BTU)

Turbine	W501AA			GE F7		
MW	55			150		
MMBtu/hr	789			1624		
Load						
100.0%	0.010001	1.04E-02	1.00	0.007866	8.90E-03	1.00
90.0%		1.08E-02	1.03		9.07E-03	1.02
80.0%	0.012761	1.12E-02	1.07		9.26E-03	1.04
75.0%		1.14E-02	1.10		9.37E-03	1.05
70.0%		1.16E-02	1.12	0.012763	9.49E-03	1.07
60.0%		1.22E-02	1.18	0.008323	9.75E-03	1.10
50.0%	0.011182	1.30E-02	1.25		1.01E-02	1.13
40.0%		1.39E-02	1.34		1.05E-02	1.18
35.0%		1.45E-02	1.39		1.07E-02	1.21
30.0%	0.01627	1.52E-02	1.46	0.010765	1.10E-02	1.24
25.0%		1.61E-02	1.55		1.14E-02	1.28
		y = 0.0104x-0.317			y = 0.0089x-0.1789	

GE F3			GE LM1500			RR Avon
7.7			10.6			10.7
87			145			158
0.00764	7.60E-03	1.00	0.0133	1.33E-02	1.00	0.0311
	8.03E-03	1.06		1.67E-02	1.26	
	8.55E-03	1.12		2.16E-02	1.63	
	8.84E-03	1.16		2.49E-02	1.87	
	9.17E-03	1.21		2.90E-02	2.18	
	9.94E-03	1.31		4.06E-02	3.05	
0.011	1.09E-02	1.44		6.04E-02	4.54	
	1.23E-02	1.62		9.82E-02	7.39	
	1.32E-02	1.74		1.31E-01	9.89	
	1.43E-02	1.88		1.84E-01	13.84	
	1.58E-02	2.07	0.274	2.74E-01	20.60	0.11

$y = 0.0076x-0.5259$

$y = 0.0133x-2.1823$

	RR Spey			Solar T12000		
		12.2			9.4	
		132			100	
3.11E-02	1.00	0.00381	3.80E-03	1.00	0.00973	9.70E-03
3.42E-02	1.10		4.77E-03	1.26		1.09E-02
3.81E-02	1.23		6.15E-03	1.62		1.23E-02
4.04E-02	1.30		7.07E-03	1.86		1.32E-02
4.30E-02	1.38		8.20E-03	2.16		1.42E-02
4.95E-02	1.59		1.14E-02	3.01		1.67E-02
5.85E-02	1.88		1.69E-02	4.46		2.03E-02
7.17E-02	2.30		2.74E-02	7.22		2.58E-02
8.10E-02	2.60		3.66E-02	9.63		2.98E-02
9.32E-02	3.00		5.10E-02	13.43		3.51E-02
1.10E-01	3.54	0.0758	7.56E-02	19.90	0.0428	4.27E-02

y = 0.0311x-0.9113 y = 0.0038x-2.1572 y = 0.0097x-1.06

	Solar T14000				Solar LoNOx	
	10.9			10.9		
	110			110		
1.00	0.00557	5.60E-03	1.00	0.0031	1.30E-03	1.00
1.12		6.67E-03	1.19		2.07E-03	1.60
1.27		8.11E-03	1.45		3.50E-03	2.69
1.36		9.03E-03	1.61	0.00255	4.66E-03	3.58
1.46		1.01E-02	1.81		6.32E-03	4.87
1.73		1.31E-02	2.34		1.25E-02	9.64
2.10		1.77E-02	3.16	0.00825	2.81E-02	21.64
2.66		2.57E-02	4.58		7.57E-02	58.23
3.07		3.20E-02	5.72	0.368	1.37E-01	105.29
3.62		4.14E-02	7.39		2.71E-01	208.61
4.40	0.0557	5.60E-02	10.00		6.09E-01	468.34

685 y = 0.0056x-1.661 y = 0.0013x-4.4357

	RR Spey				Solar T12000	
		12.2			9.4	
		132			100	
3.11E-02	1.00	0.00381	3.80E-03	1.00	0.00973	9.70E-03
3.42E-02	1.10		4.77E-03	1.26		1.09E-02
3.81E-02	1.23		6.15E-03	1.62		1.23E-02
4.04E-02	1.30		7.07E-03	1.86		1.32E-02
4.30E-02	1.38		8.20E-03	2.16		1.42E-02
4.95E-02	1.59		1.14E-02	3.01		1.67E-02
5.85E-02	1.88		1.69E-02	4.46		2.03E-02
7.17E-02	2.30		2.74E-02	7.22		2.58E-02
8.10E-02	2.60		3.66E-02	9.63		2.98E-02
9.32E-02	3.00		5.10E-02	13.43		3.51E-02
1.10E-01	3.54	0.0758	7.56E-02	19.90	0.0428	4.27E-02
y = 0.0311x-0.9113			y = 0.0038x-2.1572			y = 0.0097x-1.06

	Solar T14000			Solar LoNOx		
	10.9			10.9		
	110			110		
1.00	0.00557	5.60E-03	1.00	0.0031	1.30E-03	1.00
1.12		6.67E-03	1.19		2.07E-03	1.60
1.27		8.11E-03	1.45		3.50E-03	2.69
1.36		9.03E-03	1.61	0.00255	4.66E-03	3.58
1.46		1.01E-02	1.81		6.32E-03	4.87
1.73		1.31E-02	2.34		1.25E-02	9.64
2.10		1.77E-02	3.16	0.00825	2.81E-02	21.64
2.66		2.57E-02	4.58		7.57E-02	58.23
3.07		3.20E-02	5.72	0.368	1.37E-01	105.29
3.62		4.14E-02	7.39		2.71E-01	208.61
4.40	0.0557	5.60E-02	10.00		6.09E-01	468.34

685 y = 0.0056x-1.661 y = 0.0013x-4.4357

Formaldehyde (lb/10^{12} BTU)

Turbine	W501AA				GE F7		
MW		55			150		
MMBtu/hr		789			1624		
Load							
100.0%		87	65.099	1.00	15.3	11.268	1.00
90.0%			81.83627623	1.26		19.69919492	1.75
80.0%		77	105.6899744	1.62		36.78358349	3.26
75.0%			121.5916555	1.87		51.79162362	4.60
70.0%			141.2455922	2.17	47	74.66576859	6.63
60.0%			197.4073174	3.03	175	169.0700667	15.00
50.0%		272	293.306143	4.51		444.5061482	39.45
40.0%			476.1903982	7.31		1451.058663	128.78
35.0%			636.3876536	9.78		2945.455555	261.40
30.0%		985	889.4265483	13.66	7539	6669.56728	591.90
25.0%			1321.502535	20.30		17535.11855	1556.19
			y = 65.099x-2.1717			y = 11.268x-5.3019	

GE F3				GE LM1500			RR Avon
	7.7			10.6			10.7
	87			145			158
	260	260	1.00	4189	4189	1.00	5607
		279.5585662	1.08		4804.671881	1.15	
		303.1699841	1.17		5600.653985	1.34	
		316.9430072	1.22		6091.414125	1.45	
		332.3593165	1.28		6663.697306	1.59	
		369.5677171	1.42		8144.163952	1.94	
	419	418.9887836	1.61		10325.2577	2.46	
		488.557011	1.88		13804.77338	3.30	
		535.5954837	2.06		16425.01598	3.92	
		595.5566471	2.29		20074.14456	4.79	
		675.1984645	2.60	25450	25450.21403	6.08	14997

$y = 260x^{-0.6884}$

$y = 4189x^{-1.3015}$

	RR Spey				Solar T12000	
		12.2			9.4	
		132			100	
5607	1.00	18.5	18.5	1.00	15.6	15.6
6042.332876	1.08		30.48620849	1.65		25.3813696
6569.126005	1.17		53.28591272	2.88		43.7350348
6877.008759	1.23		72.35920468	3.91		58.92730423
7222.11629	1.29		100.3567135	5.42		81.04769595
8057.060295	1.44		208.417636	11.27		165.2043398
9170.046629	1.64		494.6805499	26.74		383.5508701
10743.56907	1.92		1424.838087	77.02		1075.295555
11811.51117	2.11		2683.487255	145.05		1992.686814
13177.03203	2.35		5572.981122	301.24		4061.81207
14997.28111	2.67	13227	13227.50521	715.00	9430	9430.209614
y = 5607x-0.7097			y = 18.5x-4.7409			y = 15.6x-4.6198

		Solar T14000			Solar LoNOx		
		10.9			10.9		
		110			110		
	1.00	2.2	2.2	1.00	14.6	9.4077	1.00
	1.63		3.753615329	1.71		19.35483946	2.06
	2.80		6.820778947	3.10		43.35468248	4.61
	3.78		9.461544285	4.30	49	67.44526777	7.17
	5.20		13.4245439	6.10		108.1714547	11.50
	10.59		29.3341373	13.33		310.8164768	33.04
	24.59		73.94104478	33.61	588	1083.093484	115.13
	68.93		229.2434189	104.20		4991.35539	530.56
	127.74		451.1930918	205.09	20347	12453.60691	1323.77
	260.37		985.907618	448.14		35783.80484	3803.67
	604.50	2485	2485.126411	1129.60		124694.824	13254.55
8			y = 2.2x-5.0708			y = 9.4077x-6.8471	

Benzene (lb/10^{12} BTU)

Turbine	W501AA			GE F7			
MW	55				150		
MMBtu/hr	789				1624		
Load							
100.0%	6.4	6.49E-06	1.00		1.3	1.27E-06	1.00
90.0%		6.68E-06	1.03			1.52E-06	1.20
80.0%	7.9	6.91E-06	1.06			1.85E-06	1.46
75.0%		7.04E-06	1.08			2.07E-06	1.63
70.0%		7.17E-06	1.11		2.2	2.32E-06	1.83
60.0%		7.49E-06	1.15		3.1	3.02E-06	2.37
50.0%	6.3	7.88E-06	1.21			4.11E-06	3.23
40.0%		8.39E-06	1.29			5.99E-06	4.72
35.0%		8.71E-06	1.34			7.51E-06	5.91
30.0%	10.1	9.10E-06	1.40		9.8	9.75E-06	7.68
25.0%		9.58E-06	1.48			1.33E-05	10.45

$y = 6.49x^{-0.2807}$

$y = 1.2705x^{-1.6929}$

GE F3				GE LM1500			RR Avon
	7.7			10.6			10.7
	87			145			158
	3.4	3.40E-06	1.00	39	3.90E-05	1.00	15.7
		3.51E-06	1.03		5.33E-05	1.37	
		3.64E-06	1.07		7.55E-05	1.94	
		3.71E-06	1.09		9.14E-05	2.34	
		3.79E-06	1.11		1.12E-04	2.87	
		3.97E-06	1.17		1.77E-04	4.53	
	4.2	4.20E-06	1.24		3.03E-04	7.78	
		4.50E-06	1.32		5.87E-04	15.05	
		4.68E-06	1.38		8.72E-04	22.35	
		4.91E-06	1.44		1.38E-03	35.27	
		5.19E-06	1.53	2359	2.36E-03	60.49	53

y = 3.4x-0.3049

y = 39x-2.9593

		RR Spey			Solar T12000	
		12.2			9.4	
		132			100	
1.57E-05	1.00	5.7	5.70E-06	1.00	2	2.00E-06
1.72E-05	1.10		6.87E-06	1.21		2.26E-06
1.91E-05	1.22		8.47E-06	1.49		2.60E-06
2.02E-05	1.29		9.49E-06	1.67		2.80E-06
2.15E-05	1.37		1.07E-05	1.88		3.04E-06
2.46E-05	1.57		1.41E-05	2.47		3.65E-06
2.88E-05	1.84		1.95E-05	3.42		4.52E-06
3.51E-05	2.23		2.89E-05	5.08		5.87E-06
3.94E-05	2.51		3.67E-05	6.43		6.87E-06
4.52E-05	2.88		4.82E-05	8.46		8.23E-06
5.30E-05	3.38	63	6.66E-05	11.68	10.2	1.02E-05
y = 15.7x-0.8776			y = 5.7x-1.7332			y = 2x-1.1752

Solar T14000

	10.9	
	110	
1.00	1.3	1.30E-06
1.13		1.36E-06
1.30		1.43E-06
1.40		1.48E-06
1.52		1.52E-06
1.82		1.63E-06
2.26		1.77E-06
2.94		1.95E-06
3.43		2.07E-06
4.12		2.21E-06
5.10	2.4	2.40E-06

y = 1.3x-0.4423

Solar LoNOx

	10.9		
	110		
1.00	2.9	1.61E-06	1.68%
1.05		2.19E-06	2.30%
1.10		3.11E-06	3.25%
1.14	2.4	3.76E-06	3.93%
1.17		4.60E-06	4.81%
1.25		7.25E-06	7.58%
1.36	5.7	1.24E-05	12.97%
1.50		2.39E-05	25.04%
1.59	67	3.55E-05	37.11%
1.70		5.59E-05	58.44%
1.85		9.56E-05	100.00%

y = 1.6089x-2.9464

ID_NUMBER	*ENG_MANUF*	*ENG_MODEL*	*MODE*	*UELFLOWLB*	*UELFLOWKG*	*Load (%)*
222	GE	CF700-2D	IDLE	460.3252	208.8000	17.6829%
222	GE	CF700-2D	APPROACH	920.6504	417.6000	35.3659%
222	GE	CF700-2D	CLIMB OUT	2190.5129	993.6000	84.1463%
222	GE	CF700-2D	TAKE-OFF	2603.2182	1180.8000	100.0000%
340	GE	CF6-80C2B6F	IDLE	1557.9626	706.6800	7.7283%
340	GE	CF6-80C2B6F	APPROACH	5103.2602	2314.8000	25.3150%
340	GE	CF6-80C2B6F	CLIMB OUT	16032.0148	7272.0000	79.5276%
340	GE	CF6-80C2B6F	TAKE-OFF	20159.0681	9144.0000	100.0000%

	CF700-2D				CF6-80C2B6F	
Load	CO	CO	HC	HC	CO	CO
100.0%	1.18E+00	1.00	4.00E-03	1.00	1.97E-02	1.00
90.0%	1.32E+00	1.12	5.53E-03	1.38	2.36E-02	1.20
80.0%	1.51E+00	1.28	7.94E-03	1.99	2.89E-02	1.47
75.0%	1.62E+00	1.37	9.68E-03	2.42	3.23E-02	1.64
70.0%	1.75E+00	1.48	1.20E-02	2.99	3.64E-02	1.85
60.0%	2.07E+00	1.76	1.92E-02	4.81	4.75E-02	2.41
50.0%	2.53E+00	2.15	3.37E-02	8.41	6.51E-02	3.30
40.0%	3.24E+00	2.75	6.68E-02	16.70	9.56E-02	4.85
35.0%	3.75E+00	3.18	1.01E-01	25.18	1.20E-01	6.11
30.0%	4.45E+00	3.77	1.62E-01	40.43	1.57E-01	7.97
25.0%	5.44E+00	4.61	2.83E-01	70.81	2.15E-01	10.91

$y = 1.1796x^{-1.1028}$ $y = 0.004x^{-3.0729}$ $y = 0.0197x^{-1.724}$

CO_LB_HR	CO_KG_HR	CO lb/MMBtu		HC_LB_HR	HC_KG_HR	HC lb/MMBtu
71.35040	32.36400	8.42391	100.0%	8.28585	3.75840	0.97826
57.08032	25.89120	3.36956	40.0%	1.28891	0.58464	0.07609
59.14385	26.82720	1.46739	17.4%	0.21905	0.09936	0.00543
57.27080	25.97760	1.19565	14.2%	0.26032	0.11808	0.00543
68.37898	31.01619	2.38533	100.0%	15.17456	6.88306	0.52935
9.79826	4.44442	0.10435	4.4%	0.96962	0.43981	0.01033
8.33665	3.78144	0.02826	1.2%	1.28256	0.58176	0.00435
10.48272	4.75488	0.02826	1.2%	1.41113	0.64008	0.00380

HC	HC
2.50E-03	1.00
3.04E-03	1.22
3.78E-03	1.51
4.26E-03	1.71
4.85E-03	1.94
6.45E-03	2.58
9.05E-03	3.62
1.37E-02	5.48
1.75E-02	7.02
2.34E-02	9.34
3.28E-02	13.10

$y = 0.0025x-1.8558$

	NOX_LB_HR	NOX_KG_HR	OX lb/MMBtu	SOX_LB_HR	SOX_KG_HR	OX lb/MMBtu
100.0%	0.41429	0.18792	0.04891	0.00001	0.00000	1.18E-06
7.8%	1.65717	0.75168	0.09783	0.00003	0.00001	1.77E-06
0.6%	9.63826	4.37184	0.23913	0.00018	0.00008	4.47E-06
0.6%	14.57802	6.61248	0.30435	0.00026	0.00012	5.43E-06
100.0%	5.84236	2.65005	0.20380	0.00009	0.00004	3.14E-06
2.0%	46.23554	20.97209	0.49239	0.00098	0.00044	1.04E-05
0.8%	370.17922	167.91048	1.25489	0.00972	0.00441	3.30E-05
0.7%	648.31563	294.07104	1.74783	0.01536	0.00697	4.14E-05

SOLID_LB	SOLID_KG	SMOKE_NO
0.00000	0.00000	7.80000
0.00000	0.00000	14.00000
0.00000	0.00000	26.60000
0.00000	0.00000	31.60000
0.00000	0.00000	3.40000
0.00000	0.00000	2.30000
0.00000	0.00000	5.40000
0.00000	0.00000	8.20000

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Dr. Fox has over 30 years of experience in the field of environmental engineering, including air quality management, water quality and water supply investigations, environmental permitting, nuisance investigations, environmental impact reports, CEQA/NEPA documentation, risk assessments, and litigation support. Her technical education in environmental engineering and her broad-based knowledge of environmental regulations and industrial and commercial facilities has been instrumental in her successful management of a wide variety of environmental projects.

EDUCATION

Ph.D. Environmental Engineering, University of California, Berkeley, 1980.
M.S. Environmental Engineering, University of California, Berkeley, 1975.
B.S. Physics (with high honors), University of Florida, Gainesville, 1971.

Post-Graduate:
S-Plus Data Analysis, MathSoft, 6/94.
Air Pollutant Emission Calculations, UC Berkeley Extension, 6-7/94
Assessment, Control and Remediation of LNAPL Contaminated Sites, API and USEPA, 9/94
Pesticides in the TIE Process, SETAC, 6/96
Sulfate Minerals: Geochemistry, Crystallography, and Environmental Significance, Mineralogical Society of America/Geochemical Society, 11/00.
Design of Gas Turbine Combined Cycle and Cogeneration Systems, Thermoflow, 12/00

REGISTRATION

Class I Environmental Assessor, California (REA-00704)
Class II Environmental Assessor, California (REA-20040)
Qualified Environmental Professional (QEP #02-010007), Institute of Professional Environmental Practice
Professional Engineer (Environmental), Arizona (#36701)

PROFESSIONAL HISTORY

Environmental Management, Principal, 1981-present
Lawrence Berkeley Laboratory, Principal Investigator, 1977-1981
University of California, Berkeley, Program Manager, 1976-1977
Bechtel, Inc., Engineer, 1971-1976

PROFESSIONAL AFFILIATIONS

Society of Environmental Toxicology and Chemistry
Association for the Environmental Health of Soils
Air and Waste Management Association
American Chemical Society
Phi Beta Kappa
Sigma Pi Sigma

Who's Who Environmental Registry, PH Publishing, Fort Collins, CO, 1992.
Who's Who in the World, Marquis Who's Who, Inc., Chicago, IL, 11th Ed., p. 371, 1993-present.
Who's Who of American Women, Marquis Who's Who, Inc., Chicago, IL, 13th Ed., p. 264, 1984-present.
Who's Who in Science and Engineering, Marquis Who's Who, Inc., New Providence, NJ, 5th Ed., p. 414, 1999-present.
Guide to Specialists on Toxic Substances, World Environment Center, New York, NY, p. 80, 1980.
National Research Council Committee on Irrigation-Induced Water Quality Problems (Selenium), Subcommittee on Quality Control/Quality Assurance (1985-1990).
National Research Council Committee on Surface Mining and Reclamation, Subcommittee on Oil Shale (1978-80)

REPRESENTATIVE EXPERIENCE

Performed environmental investigations, as outlined below, for a wide range of industrial and commercial facilities including refineries, reformulated fuels projects, petroleum distribution terminals, conventional and thermally enhanced oil production, underground storage tanks, pipelines, gasoline stations, landfills, railyards, hazardous waste treatment facilities, power plants, airports, hydrogen plants, asphalt plants, cement plants, incinerators, flares, manufacturing facilities (semiconductors, electronic assembly, aerospace components, printed circuit boards, amusement park rides), lanthanide processing plants, ammonia plants, urea plants, food processing plants, grain processing facilities, paint formulation plants, wastewater treatment plants, marine terminals, gas processing plants, steel mills, battery manufacturing plants, pesticide manufacturing and repackaging facilities, pulp and paper mills, redevelopment projects (e.g., Mission Bay, Southern Pacific Railyards, Moscone Center expansion, San Diego Padres Ballpark), commercial office parks, campuses, and shopping centers, server farms, and a wide range of mines including sand and gravel, hard rock, limestone, nacholite, coal, molybdenum, gold, zinc, and oil shale.

Environmental Management/Investigations

- Air quality investigations, including emission inventories, BACT/MACT/LAER analyses, PSD and NSR permitting, emissions reduction credits and offset programs, air quality monitoring, and air quality modeling.
- Nuisance investigations (odor, noise, dust, smoke, indoor air quality, contamination).
- Property damage from environmental contamination.
- Accident investigation and reconstruction. Risk of upset analyses.
- Environmental forensics.
- Geohydrologic, water quality, and water supply investigations. Isotope studies. Engineering and modeling studies on surface and ground water contamination, thermal pollution, eutrophication, industrial waste treatment, and solid waste disposal.
- Literature surveys, historical research, and file reviews.
- Health risk assessments, preliminary endangerment assessments, and other health studies.
- Statistical analyses and computer simulations of natural systems. Modelling using agency and other software including Systat, S-Plus, ISC, SCREEN, ACE 2588, CALINE-4, EMFFAC7G, URBEMIS, DEGADIS, ALOHA, Visual MODFLOW and MT3D, among others.
- Environmental monitoring programs, including ambient air quality, indoor air quality, surface water quality, and groundwater quality.
- Hazardous waste investigations including phase I/II assessments, remedial investigations, feasibility studies, remedial action plans, work plans, closure plans, and other environmental investigations and documentation.
- Environmental compliance audits of industrial properties including electric utilities, refineries, and a wide range of manufacturing facilities.

EXPERT WITNESS/LITIGATION SUPPORT

- Represent Florida city in challenging prevention of significant deterioration (PSD) permits issued to two 510-MW simple cycle peaking electric generating facilities based on proposed

BACT limits. Reviewed permit applications, draft permits, and FDEP engineering evaluation and assisted counsel in drafting petition.

- Represented coalition of Georgia environmental groups in challenging PSD permit issued to 1,240 MW natural gas combined-cycle power plant based on proposed BACT limits. Prepared technical comments on draft PSD permit on BACT, enforceability of limits, and toxic emissions. Reviewed responses to comments and advised counsel on merits. Assisted in drafting petition appealing permit. Case settled July 2001.

- Represent construction unions in review of air quality permitting actions before the Indiana Department of Environmental Management for several simple cycle peakers and combined cycle power plants. Cases in progress.

- Represent coalition of towns and environmental groups in challenging air permits issued to 523 MW dual fuel (natural gas and distillate) combined-cycle power plant in Connecticut. Prepared technical comments on draft permits and 60 pages of written testimony addressing emission estimates, startup/shutdown issues, BACT/LAER analyses, and toxic air emissions. Presented testimony in administrative hearings before the Connecticut Department of Environmental Protection in June 2001.

- Represented coalitions of unions, citizens groups, and developers in licensing and permitting of over 12 combined cycle, simple cycle, and peaker power plants in California. Prepared analyses of and comments on applications for certification, preliminary and final staff assessments, and permits issued by local agencies. Presented testimony before California Energy Commission on hazards of ammonia use and transportation, health effects of air emissions, contaminated property issues, BACT/LAER issues related to SCR and SCONOx, emission estimates, air quality modeling, water supply and water quality issues, and methods to reduce water use, including dry cooling, hybrid dry-wet cooling, and zero liquid discharge systems.

- Represented lessor of former gas station with leaking underground storage tanks and TCE contamination from adjacent property. Lessor held option to purchase, which was forfeited based on misrepresentation by remediation contractor as to nature and extent of contamination. Remediation contractor purchased property. Reviewed regulatory agency files and advised counsel on merits of case.

- Advised counsel on merits of several pending actions, including a Proposition 65 suite involving groundwater contamination at an explosives manufacturing firm and two former gas stations with leaking underground storage tanks.

- Represented defendant foundry in Oakland in a lawsuit brought by neighbors alleging property contamination, nuisance, trespass, smoke, and health effects from foundry operation. Inspected and sampled plaintiff's property. Advised counsel on merits of case.

- Advised counsel on merits of two proposed appeals of PSD permits for natural-gas fired power plants. Assisted counsel in developing technical arguments and drafted portions of the appeals and briefs.

- Represented business owner facing eminent domain eviction. Prepared technical comments on a negative declaration for soil contamination and public health risks from air emissions from a proposed redevelopment project in San Francisco in support of a CEQA lawsuit. Case settled.

- Represented residents living downwind of a Berkeley asphalt plant in separate nuisance and CEQA lawsuits. Prepared technical comments on air quality, odor, and noise impacts, presented testimony at commission and council meetings, participated in community workshops, and participated in settlement discussions. Cases settled. Asphalt plant was upgraded to include air emission and noise controls, including vapor collection system at truck loading station, enclosures for noisy equipment, and improved housekeeping.

- Represented a Fortune 500 residential home builder in claims alleging health effects from faulty installation of gas appliances. Conducted indoor air quality study, advised counsel on merits of case, and participated in discussions with plaintiffs. Case settled.

- Represented property owners in Silicon Valley in suit to recover remediation costs from insurer for large TCE plume originating from a manufacturing facility. Conducted investigations to demonstrate sudden and accidental release of TCE, including groundwater modeling, development of method to date spill, preparation of chemical inventory, investigation of historical waste disposal practices and standards, and on-site sewer and storm drainage inspections and sampling. Prepared declaration in opposition to motion for summary judgment. Case settled.

- Represented residents in east Oakland downwind of a former battery plant in class action lawsuit alleging property contamination from lead emissions. Conducted historical research and dry deposition modeling that substantiated claim. Participated in mediation at JAMS. Case settled.

- Represented property owners in West Oakland who purchased a former gas station that had leaking underground storage tanks and groundwater contamination. Reviewed agency files and advised counsel on merits of case. Prepared declaration in opposition to summary judgment. Prepared cost estimate to remediate site. Participated in settlement discussions. Case settled.

- Consultant to counsel representing plaintiffs in two Clean Water Act lawsuits involving selenium discharges into San Francisco Bay from refineries. Reviewed files and advised counsel on merits of case. Prepared interrogatory and discovery questions, assisted in deposing opposing experts, and reviewed and interpreted treatability and other technical studies. Judge ruled in favor of plaintiffs.

- Represented an oil company in a complaint filed by a resident of a small beach community alleging that discharges of tank farm rinse water into the sanitary sewer system caused hydrogen sulfide gas to infiltrate residence, sending occupants to hospital. Inspected accident site, interviewed parties to the event, and reviewed extensive agency files related to incident. Used chemical analysis, field simulations, mass balance calculations, sewer hydraulic simulations with SWMM44, atmospheric dispersion modeling with SCREEN3, odor analyses, and risk assessment calculations to demonstrate that the incident was caused by a faulty drain trap and inadequate slope of sewer lateral on resident's property. Prepared a detailed technical report summarizing these studies. Case settled.

- Represented large West Coast city in suit alleging that leaking underground storage tanks on city property had damaged the waterproofing on downgradient building, causing leaks in an underground parking structure. Reviewed subsurface hydrogeologic investigations and evaluated studies conducted by others documenting leakage from underground diesel and gasoline tanks. Inspected, tested, and evaluated waterproofing on subsurface parking structure. Waterproofing was substandard. Case settled.

- Represented residents downwind of gravel mine and asphalt plant in Siskiyou County in suit to obtain CEQA review of air permitting action. Prepared two declarations analyzing air quality and public health impacts. Judge ruled in favor of plaintiffs, closing mine and asphalt plant.

- Represented defendant oil company on the California Central Coast in class action lawsuit alleging property damage and health effects from subsurface petroleum contamination. Reviewed documents, prepared risk calculations, and advised counsel on merits of case. Participated in settlement discussions. Case settled.

- Represented defendant oil company in class action lawsuit alleging health impacts from remediation of petroleum contaminated site on California Central Coast. Reviewed documents, designed and conducted monitoring program, and participated in settlement discussions. Case settled.

- Consultant to attorneys evaluating a potential challenge of USFWS actions under CVPIA section 3406(b)(2). Reviewed agency files and collected and analyzed hydrology, water quality, and fishery data. Advised counsel on merits of case. Case not filed.

- Represented residents downwind of a Carson refinery in class action lawsuit involving soil and groundwater contamination, nuisance, property damage, and health effects from air emissions. Reviewed files and provided advise on contaminated soil and groundwater, toxic emissions, and health risks. Prepared declaration on refinery fugitive emissions. Prepared deposition questions and reviewed deposition transcripts on air quality, soil contamination, odors, and health impacts. Case settled.

- Represented residents downwind of a Contra Costa refinery who were affected by an accidental release of naphtha. Characterized spilled naphtha, estimated emissions, and modeled ambient concentrations of hydrocarbons and sulfur compounds. Deposed. Presented testimony in binding arbitration at JAMS. Judge found in favor of plaintiffs.

- Represented residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects from several large accidents as well as routine operations. Reviewed files and prepared analyses of environmental impacts. Prepared declarations, deposed, and presented testimony before jury in one trial and judge in second. Case pending.

- Represented business owner claiming damages from dust, noise, and vibration during a sewer construction project in San Francisco. Reviewed agency files and PM10 monitoring data and advised counsel on merits of case. Case settled.

- Represented residents downwind of Contra Costa County refinery in class action lawsuit alleging property damage, nuisance, and health effects. Prepared declaration in opposition to summary judgment, deposed, and presented expert testimony on accidental releases, odor, and nuisance before jury. Case thrown out by judge, but reversed on appeal and to be retried.

- Presented testimony in small claims court on behalf of residents claiming health effects from flaring emissions triggered by a power outage at a Contra Costa County refinery. Analyzed meteorological and air quality data and evaluated potential health risks of exposure to low concentrations of hydrogen sulfide.

- Represented construction unions in Prevention of Significant Deterioration permitting action for an Indiana steel mill. Prepared technical comments on draft PSD permit, drafted 70-page appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analysis for electric arc furnace and reheat furnace and faulty permit conditions, among others, and drafted briefs responding to four parties. EPA Region V and the EPA General Counsel intervened as amici, supporting petitioners. EAB ruled in favor of petitioners, remanding permit to IDEM on three key issues, including BACT for the reheat furnace and lead emissions from the EAF. Drafted motion to reconsider three issues. Prepared 69 pages of technical comments on revised draft PSD permit. Drafted second EAB appeal addressing lead emissions from the EAF and BACT for reheat furnace based on European experience with SCR/SNCR. Case settled.

- Represented defendant urea manufacturer in Alaska in negotiations with USEPA to seek relief from penalties for alleged violations of the Clean Air Act. Reviewed and evaluated regulatory files and monitoring data, prepared technical analysis demonstrating that permit limits were not violated, and participated in negotiations with EPA to dismiss action. Fines were substantially reduced and case closed.

- Represented construction unions in Prevention of Significant Deterioration permitting action for an Indiana grain mill. Prepared technical comments on draft PSD permit and assisted counsel draft appeal of agency permit action to the Environmental Appeals Board challenging permit based on faulty BACT analyses for heaters and boilers and faulty permit conditions, among others. Case settled.

- As part of a consent decree settling a CEQA lawsuit, represented neighbors of a large west coast port in negotiations with port authority to secure mitigation for air quality impacts. Prepared technical comments on mobile source air quality impacts and mitigation and negotiated a $9 million CEQA mitigation package. Currently representing neighbors on technical advisory committee established by port to implement the air quality mitigation program.

- Represented construction unions in permitting action for a California hazardous waste incinerator. Prepared technical comments on draft permit, assisted counsel prepare appeal of EPA permit to the Environmental Appeals Board. Participated in settlement discussions on technical issues with applicant and EPA Region 9. Case settled.

- Represented environmental group in challenge of DTSC Negative Declaration on a hazardous waste treatment facility. Prepared technical comments on risk of upset, water, and health risks. Writ of mandamus issued.

- For over 100 industrial facilities, commercial/campus, and redevelopment projects, developed the record in preparation for CEQA and NEPA lawsuits. Prepared technical comments on hazardous materials, solid wastes, public utilities, noise, worker safety, air quality, public health, water resources, water quality, and risk of upset sections of EIRs, EISs, initial studies, and negative declarations. Assisted counsel in drafting petitions and briefs and prepared declarations.

- For several large commercial development projects, assisted applicant and counsel respond to comments and identify and evaluate "all feasible" mitigation to avoid CEQA challenges. This work included developing mitigation programs to reduce traffic-related air quality impacts based on energy conservation programs, photovoltaics, low-emission vehicles, alternative fuels, exhaust treatments, and transportation management associations.

SITE INVESTIGATION/REMEDIATION/CLOSURE

- Technical manager and principal engineer for characterization, remediation, and closure of waste management units at former oil shale plant in Colorado. Constituents of concern included BTEX, As, 1,1,1-TCA, and TPH. Completed groundwater monitoring programs, site assessments, work plans, and closure plans for seven process water holding ponds, a refinery sewer system, and processed shale disposal area. Managed design and construction of groundwater treatment system and removal actions and obtained clean closure.

- Principal engineer for characterization, remediation, and closure of process water ponds at a former lanthanide processing plant in Colorado. Designed and implemented groundwater monitoring program and site assessments and prepared closure plan.

- Advised the city of Sacramento on redevelopment of two former railyards. Reviewed work plans, site investigations, risk assessment, RAPS, RI/FSs, and CEQA documents. Participated in the development of mitigation strategies to protect construction and utility workers and the public during remediation, redevelopment, and use of the site, including buffer zones, subslab venting, rail berm containment structure, and an environmental oversight plan.

- Provided technical support for the investigation of a former sanitary landfill that was redeveloped as single family homes. Reviewed and/or prepared portions of numerous documents, including health risk assessments, preliminary endangerment assessments, site investigation reports, work plans, and RI/FSs. Historical research to identify historic waste disposal practices to prepare a preliminary endangerment assessment. Acquired, reviewed, and analyzed the files of 18 federal, state, and local agencies, three sets of construction field notes, analyzed 21 aerial photographs and interviewed 14 individuals associated with operation of former landfill. Prepared summary reports.

- Technical oversight of characterization and remediation of a nitrate plume at an explosives manufacturing facility in Lincoln, CA. Provided interface between owners and consultants. Reviewed site assessments, work plans, closure plans, and RI/FSs.

- Consultant to owner of large western molybdenum mine proposed for NPL listing. Participated in negotiations to scope out consent order and develop scope of work.

Participated in studies to determine premining groundwater background to evaluate applicability of water quality standards. Served on technical committees to develop alternatives to mitigate impacts and close the facility, including resloping and grading, various thickness and types of covers, and reclamation. This work included developing and evaluating methods to control surface runoff and erosion, mitigate impacts of acid rock drainage on surface and ground waters, and stabilize nine waste rock piles containing 328 million tons of pyrite-rich, mixed volcanic waste rock (andesites, rhyolite, tuff). Evaluated stability of waste rock piles. Represented client in hearings and meetings with state and federal oversight agencies.

REGULATORY PERMITTING/NEGOTIATIONS

- Prepared Authority to Construct Permit for remediation of a large petroleum-contaminated site on the Central Coast. Negotiated conditions with agencies and secured permits.

- Prepared Authority to Construct Permit for remediation of a former oil field on the Central Coast. Participated in negotiations with agencies and secured permits.

- Prepared and/or reviewed hundreds of environmental permits, including NPDES, UIC, Stormwater, Authority to Construct, Prevention of Significant Deterioration, New Source Review, and RCRA, among others.

- Participated in the development of the CARB document, *Guidance for Power Plant Siting and Best Available Control Technology*, including attending public workshops and filing technical comments.

- Performed data analyses in support of adoption of emergency power restoration standards by the Public Utilities Commission for "major" power outages, where major is an outage that simultaneously affects 10% of the customer base.

- Drafted portions of the Good Neighbor Ordinance to grant Contra Costa County greater authority over safety of local industry, particularly chemical plants and refineries.

- Participated in drafting BAAQMD Regulation 8, Rule 28, Pressure Relief Devices, including participation in public workshops, review of staff reports, draft rules and other technical materials, preparation of technical comments on staff proposals, research on availability and costs of methods to control PRV releases, and negotiations with staff.

- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and cost of low-leak technology, and negotiations with staff.

- Participated in amending BAAQMD Regulation 8, Rule 25, Pumps and Compressors, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak and seal-less technology, and negotiations with staff.

- Participated in amending BAAQMD Regulation 8, Rule 5, Storage of Organic Liquids, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of controlling tank emissions, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 18, Valves and Connectors at Petroleum Refinery Complexes, including participation in public workshops, review of staff reports, proposed rules and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 22, Valves and Flanges at Chemical Plants, etc, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability and costs of low-leak technology, and presentation of testimony before the Board.

- Participated in amending BAAQMD Regulation 8, Rule 25, Pump and Compressor Seals, including participation in public workshops, review of staff reports, proposed rules, and other supporting technical material, preparation of technical comments on staff proposals, research on availability of low-leak technology, and presentation of testimony before the Board.

- Participated in the development of the BAAQMD Regulation 2, Rule 5, Toxics, including participation in public workshops, review of staff proposals, and preparation of technical comments.

- Participated in the development of SCAQMD Rule 1402, Control of Toxic Air Contaminants from Existing Sources, and proposed amendments to Rule 1401, New Source Review of Toxic Air Contaminants, in 1993, including review of staff proposals and preparation of technical comments on same.

- Participated in the development of the Sunnyvale Ordinance to Regulate the Storage, Use and Handling of Toxic Gas, which was designed to provide engineering controls for gases that are not otherwise regulated by the Uniform Fire Code.

- Participated in the drafting of the Statewide Water Quality Control Plans for Inland Surface Waters and Enclosed Bays and Estuaries, including participation in workshops, review of draft plans, preparation of technical comments on draft plans, and presentation of testimony before the SWRCB.

- Participated in developing Se permit effluent limitations for the five Bay Area refineries, including review of staff proposals, statistical analyses of Se effluent data, review of literature on aquatic toxicity of Se, preparation of technical comments on several staff proposals, and presentation of testimony before the Bay Area RWQCB.

- Represented the California Department of Water Resources in the 1991 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on a striped bass model developed by the California Department of Fish and Game.

- Represented the State Water Contractors in the 1987 Bay-Delta Hearings before the State Water Resources Control Board, presenting sworn expert testimony with cross examination and rebuttal on natural flows, historical salinity trends in San Francisco Bay, Delta outflow, and hydrodynamics of the South Bay.

- Represented interveners in the licensing of 12 natural-gas-fired power plants and one coal gasification plant at the California Energy Commission. Reviewed and prepared technical comments on applications for certification, preliminary staff assessments, final staff assessments, preliminary determinations of compliance, final determinations of compliance, and prevention of significant deterioration permits in the areas of air quality, water supply, water quality, biology, public health, worker safety, transportation, site contamination, and hazardous materials. Presented written and oral testimony in evidentiary hearings with cross examination and rebuttal. Participated in technical workshops.

- Represented several parties in the proposed merger of San Diego Gas & Electric and Southern California Edison. Prepared independent technical analyses on health risks, air quality, and water quality. Presented written and oral testimony before the Public Utilities Commission administrative law judge with cross examination and rebuttal.

- Represented a PRP in negotiations with local health and other agencies to establish impact of subsurface contamination on overlying residential properties. Reviewed health studies prepared by agency consultants and worked with agencies and their consultants to evaluate health risks.

WATER QUALITY/RESOURCE PLANNING

- Directed and participated in research on environmental impacts of energy development in the Colorado River Basin, including contamination of surface and subsurface waters and modeling of flow and chemical transport through fractured aquifers.

- Played a major role in Northern California water resource planning studies since the early 1970s. Prepared portions of the Basin Plans for the Sacramento, San Joaquin, and Delta basins including sections on water supply, water quality, beneficial uses, waste load allocation, and agricultural drainage. Developed water quality models for the Sacramento and San Joaquin Rivers.

- Conducted hundreds of studies over the past 30 years on Delta water supplies and their impacts on water supply, water quality, and biological resources of the Central Valley, Sacramento-San Joaquin Delta, and San Francisco Bay. Typical examples include:

    1. Evaluate historical trends in salinity, temperature, and flow in San Francisco Bay and upstream rivers to determine impacts of water exports on the estuary;
    2. Evaluate the role of exports and natural factors on the food web by exploring the relationship between salinity and primary productivity in San Francisco Bay, upstream rivers, and ocean;
    3. Evaluate the effects of exports, other in-Delta, and upstream factors on the abundance of salmon and striped bass;
    4. Review and critique agency fishery models that link water exports with the abundance of striped bass and salmon;
    5. Develop a model based on GLMs to estimate the relative impact of exports, water facility operating variables, tidal phase, salinity, temperature, and other variables on the survival of salmon smolts as they migrate through the Delta;
    6. Reconstruct the natural hydrology of the Central Valley using water balances, vegetation mapping, reservoir operation models to simulate flood basins, precipitation records, tree ring research, and historical research;
    7. Evaluate the relationship between biological indicators of estuary health and down-estuary position of a salinity surrogate (X2);
    8. Use real-time fisheries monitoring data to quantify impact of exports on fish migration;
    9. Refine/develop statistical theory of autocorrelation and use to assess strength of relationships between biological and flow variables;

10. Collect, compile, and analyze water quality and toxicity data for surface waters in the Central Valley to assess the role of water quality in fishery declines;
11. Assess mitigation measures, including habitat restoration and changes in water project operation, to minimize fishery impacts;
12. Evaluate the impact of unscreened agricultural water diversions on abundance of larval fish;
13. Prepare and present testimony on the impacts of water resources development on Bay hydrodynamics, salinity, and temperature in water rights hearings;
14. Evaluate the impact of boat wakes on shallow water habitat, including interpretation of historical aerial photographs;
15. Evaluate the hydrodynamic and water quality impacts of converting Delta islands into reservoirs;
16. Use a hydrodynamic model to simulate the distribution of larval fish in a tidally influenced estuary;
17. Identify and evaluate non-export factors that may have contributed to fishery declines, including predation, shifts in oceanic conditions, aquatic toxicity from pesticides and mining wastes, salinity intrusion from channel dredging, loss of riparian and marsh habitat, sedimentation from upstream land alternations, and changes in dissolved oxygen, flow, and temperature below dams.

- Developed, directed, and participated in a broad-based research program on environmental issues and control technology for energy industries including petroleum, oil shale, coal mining, and coal slurry transport. Research included evaluation of air and water pollution, development of novel, low-cost technology to treat and dispose of wastes, and development and application of geohydrologic models to evaluate subsurface contamination from in-situ retorting. The program consisted of government and industry contracts and employed 45 technical and administrative personnel.

- Coordinated an industry task force established to investigate the occurrence, causes, and solutions for corrosion/erosion and mechanical/engineering failures in the waterside systems (e.g., condensers, steam generation equipment) of power plants. Corrosion/erosion failures caused by water and steam contamination that were investigated included waterside corrosion caused by poor microbiological treatment of cooling water, steam-side corrosion caused by ammonia-oxygen attack of copper alloys, stress-corrosion cracking of copper alloys in the air cooling sections of condensers, tube sheet leaks, oxygen in-leakage through condensers, volatilization of silica in boilers and carry over and deposition on turbine blades, and iron corrosion on boiler tube walls. Mechanical/engineering failures investigated included: steam impingement attack on the steam side of condenser tubes, tube-to-tube-sheet joint leakage, flow-induced vibration, structural design problems, and mechanical failures due to stresses induced by shutdown, startup and cycling duty, among others. Worked with electric utility plant owners/operators, condenser and boiler vendors, and architect/engineers to collect data to document the occurrence of and causes for these problems, prepared reports summarizing the investigations, and presented the results and participated on a committee of industry experts tasked with identifying solutions to prevent condenser failures.

- Evaluated the cost effectiveness and technical feasibility of using dry cooling and parallel dry-wet cooling to reduce water demands of several large natural-gas fired power plants to comply with SWRCB Policy 75-58.

- Designed, evaluated, and costed several zero liquid discharge systems for power plants.

- Evaluated the impact of agricultural and mining practices on surface water quality of Central Valley steams. Represented municipal water agencies on several federal and state advisory committees tasked with gathering and assessing relevant technical information, developing work plans, and providing oversight of technical work to investigate toxicity issues in the watershed.

AIR QUALITY

- Prepared or reviewed the air quality sections of hundreds of EIRs and EISs on a wide range of industrial, commercial and residential projects.

- Prepared or reviewed hundreds of NSR and PSD permits for a wide range of industrial facilities.

- Designed, implemented, and directed a 2-year-long community monitoring program to assure that residents downwind of a petroleum-contaminated site were not impacted during remediation of petroleum-contaminated soils. The program included real-time monitoring of particulates, diesel exhaust, and BTEX and time integrated monitoring for over 100 chemicals.

- Designed, implemented, and directed a 5-year long source, industrial hygiene, and ambient monitoring program to characterize air emissions, employee exposure, and downwind environmental impacts of a first-generation shale oil plant. The program included stack monitoring of heaters, boilers, incinerators, sulfur recovery units, rock crushers, API separator vents, and wastewater pond fugitives for arsenic, cadmium, chlorine, chromium, mercury, 15 organic indicators (e.g., quinoline, pyrrole, benzo(a)pyrene, thiophene, benzene), sulfur gases, hydrogen cyanide, and ammonia. In many cases, new methods had to be developed or existing methods modified to accommodate the complex matrices of shale plant gases.

- Conducted investigations on the impact of diesel exhaust from truck traffic from a wide range of facilities including mines, large retail centers, light industrial uses, and sports facilities. Conducted traffic surveys, continuously monitored diesel exhaust using an aethalometer, and prepared health risk assessments using resulting data.

- Conducted indoor air quality investigations to assess exposure to natural gas leaks, pesticides, molds and fungi, soil gas from subsurface contamination, and outgasing of carpets, drapes, furniture and construction materials. Prepared health risk assessments using collected data.

- Prepared health risk assessments, emission inventories, air quality analyses, and assisted in the permitting of over 70 1 to 2 MW emergency diesel generators.

- Developed methods to monitor trace elements in gas streams, including a continuous real-time monitor based on the Zeeman atomic absorption spectrometer, to continuously measure mercury and other elements.

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DECLARATION OF J. PHYLLIS FOX, Ph.D.

I, J. Phyllis Fox, declare as follows:

1. I prepared the attached analysis of environmental impacts of the proposed La Paz Generating Facility in La Paz County, Arizona, based on my independent review and my professional experience and knowledge.

2. It is my professional opinion that the analysis is valid and accurate with respect to the issue(s) addressed therein.

3. I am personally familiar with the facts and conclusions related in the analysis, and if called as a witness could testify competently thereto.

4. A copy of my professional qualifications and experience is attached hereto and incorporated by reference herein.

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

Dated: October 19, 2001, at Berkeley, California:

J. Phyllis Fox, Ph.D., P.E.

EXHIBITS

to the

Testimony of J. Phyllis Fox, Ph.D.

on

Air Quality Impacts

Relating to the

La Paz Generating Facility

Submitted on behalf of

Arizona Unions For Reliable Energy

October 19, 2001

1

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

June 19, 2001

Mr. David W. Dixon
Engineering Division Supervisor
San Luis Obispo Air Pollution Control District
3433 Roberto Court
San Luis Obispo, CA 93401

Re: Preliminary Determination of Compliance for Duke Energy Morro Bay LLC
CEC Docket Number 00-AFC-12

Dear Mr. Dixon:

I am writing to you concerning the Preliminary Determination of Compliance ("PDOC") for the proposed Duke Energy Morro Bay LLC project. We appreciate the opportunity to comment on the PDOC for this project. We have two comments concerning Best Available Control Technology ("BACT"):

1. **BACT for NO_x Emissions**

Although we have not seen the San Luis Obispo Air Pollution Control District ("District") top-down BACT analysis for this project, we believe the BACT limit for NO_x should be set at 2.0 ppmvd on a 1-hour rolling average. The San Joaquin Valley Unified Air Pollution Control District recently determined NO_x BACT to be 2 ppmvd @ 15% O_2 averaged over 1-hour for a similar project, the Midway Sunset Cogeneration Company 500 MW natural gas-fired combined-cycle power plant project nears Fellows, California (December 14, 2000, Notice of Final Determination of Compliance, CEC Docket No. 99-AFC-9). We also expect that 5 ppmvd ammonia slip can be achieved at the 2.0 ppmvd NO_x level.

2. **BACT for CO Emissions**

EPA believes that presumptive BACT for CO for this project, unless the data from the BACT analysis show otherwise, to be 2.0 ppmvd on a 3-hour rolling average, not the 6.0 ppmvd 3-hour rolling average that is specified in the PDOC.

We ask that the District address our comments before issuing a final Determination of Compliance. We look forward to working with you on these comments. If you have any questions, please contact me at (415) 744-1259 or have your staff contact Mark Sims at (415) 744-1229.

Sincerely,

for Gerardo Rios
Acting Chief
Air Permits Office

cc: Mr. Wayne Hoffman (Duke Energy)
Ms. Nancy Matthews (Sierra Research)
Mr. Gary Willey (SLOAPCD)
Mr. Mike Tollstrup (CARB)
Mr. Magdy Badr (CEC)

2

DRAFT

ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF: **Sumas Energy 2** **Generation Facility** **Sumas Energy 2, Inc.** **Sumas, WA**	**NO. EFSEC/00-01** **DRAFT APPROVAL OF THE PREVENTION OF SIGNIFICANT DETERIORATION AND NOTICE OF CONSTRUCTION**

EFSEC finds the following pursuant to

the Energy Facility Site Evaluation Council (EFSEC) regulations for

air permit applications (Washington Administrative Code 463-42-385),

General and Operating Permit Regulations for Air Polluting Sources (Washington Administrative Code 463-39),

the Washington Department of Ecology (Ecology) regulations for

new source review (Washington Administrative Code 173-400-110 and Chapter 174-460 WAC),

the federal Prevention of Significant Deterioration regulations (40 CFR 52.21),

the complete Notice of Construction/Prevention of Significant Deterioration Application submitted by Sumas Energy 2, Inc. and

the technical analysis performed by Ecology for EFSEC:

FINDINGS (Applicable to both the Prevention of Significant Deterioration and Notice of Construction Approval)

1. Sumas Energy 2, Inc. has applied to construct the Sumas Energy 2 Generation Facility (S2GF) which will be located in Sumas, Washington. The proposed project includes two separate but identical combustion gas turbines, one steam turbine, three electric generators, and two heat recovery steam generators (HRSG). Total power generating capacity is 660 megawatts (MW). Siemens-Westinghouse has been selected as the turbine supplier. Annual emission rates and resulting environmental impacts have been evaluated for the maximum

anticipated emissions .

2. The project is subject to federal Prevention of Significant Deterioration (PSD) regulations under Title 40 Code of Federal Regulations (CFR) 52.21 because it is one of 28 listed industries that becomes a "major source," when emitting more than 100 tons per year of any regulated pollutant. Each pollutant emitted above Significant Emission Rate thresholds must satisfy requirements under PSD. S2GF has the potential to emit quantities of nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM_{10}), volatile organic compounds (VOCs), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) above the Significant Emission Rate thresholds. In addition, S2GF has the potential to emit toxic air pollutants in quantities sufficient to require consideration under state new source review regulations.

3. The site of the proposed project is within a Class II area that is in attainment with regard to all pollutants regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is 55 kilometers (km.) from the nearest Class I Area, North Cascades National Park, within 175 km. of four other Class I areas (Alpine Lakes Wilderness, Glacier Peak Wilderness, Olympic National Park, and Pasayten Wilderness), and within one-half mile of the Canadian border.

4. The project is subject to the following requirements:

General and operating permit regulations for air pollution sources chapter 463-39 WAC.

New source review under Chapter 173-400 WAC, Chapter 173-460 WAC, 40 CFR 52.21, 40 CFR 60.40a, 40 CFR 60.330;

Emission monitoring under Chapter 70.94 RCW, Chapter 173-400 WAC, 40 CFR 60 Appendices A, B, and F, and 40 CFR 75;

Gas fuel monitoring under 40 CFR 60.334(b)(2), and to oil fuel requirements in 40 CFR 60.49b(r).

5. Sumas Energy 2, Inc.'s prevention of significant deterioration/notice of construction (PSD/NOC) application for the proposed project was determined to be complete on June 8, 2000

6. The project will use pipeline quality natural gas as the primary fuel. On-road specification (very low sulfur content) distillate oil may be used during periods of natural gas curtailment.

7. Best available control technology (BACT) as required under WAC 173-400-113 (2) and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4) will be used for the control of all air pollutants which will be emitted by the proposed project.

8. The following have been determined to be BACT for this project:

   Use of standard dry low NO_x burners with selective catalytic reduction (SCR) for NO_x control.

   Catalytic oxidation for CO control.

   Good combustion practice, using only natural gas and on-road specification, low-sulfur distillate oil with less than 0.05% sulfur as fuel, and minimizing oil-firing for VOC, PM_{10}, sulfur oxides, and organic toxic air pollutants control.

   SCR with a 10 ppmdv ammonia slip limit for ammonia control.

9. The facility will have the potential to emit up to 156 tons per year of nitrogen oxides (NO_x).

10. The facility will have the potential to emit up to 106 tons per year of carbon monoxide (CO).

11. The facility will have the potential to emit up to 156 tons per year of volatile organic compounds (VOCs).

12. The facility will have the potential to emit up to 223 tons per year of particulate matter smaller than 10 microns (PM_{10}, combined filterable and condensable).

13. The facility will have the potential to emit up to 45 tons per year of sulfur oxides (SO_2 and SO_3 or H_2SO_4 measured as SO_2).

14. The facility will have the potential to emit up to 9.3 tons per year of sulfuric acid mist (H_2SO_4). This has also been counted in Finding # 13, above.

15. The facility will have the potential to emit 272 tons per year of ammonia.

16. With the exception of sulfuric acid mist under oil-firing, no single toxic air pollutant from the facility is expected to exceed 20% of the acceptable source impact level specified in Chapter 173-460 WAC. Discounting any neutralization by reaction with the ammonia slip, sulfuric acid mist under oil-firing at permit limits may be just slightly less than the acceptable source impact level specified in Chapter 173-460 WAC.

    The average emission level of toxic air pollutants is expected to be less than 5% of the acceptable source impact level specified in Chapter 173-460 WAC.

17. Allowable emissions from the new emissions units will not cause or contribute to air pollution in violation of:
    17.1. Any ambient air quality standard;
    17.2. Any applicable maximum allowable increase over the baseline ambient concentration.

18. Ambient impact analysis indicates that there will be no significant impacts resulting from pollutant deposition on soils and vegetation in the Class I areas: Alpine Lakes Wilderness, Glacier Peak Wilderness, North Cascades National Park, Olympic National Park, and Pasayten Wilderness, the proposed Class I area, the Mt. Baker Wilderness, or in analogous areas in nearby British Columbia, Canada.

19. Ambient impact analysis indicates that it is very unlikely that the proposed emissions will

cause significant degradation of regional visibility, or impairment of visibility in any Class I area.

20. No significant effect on industrial, commercial, or residential growth in the Sumas area is anticipated due to the project.

21. EFSEC finds that all requirements for new source review (NSR) and PSD are satisfied and that as approved below, the new emissions units comply with all applicable federal new source performance standards. Approval of the PSD/NOC application is granted subject to the following conditions.

PREVENTION OF SIGNIFICANT DETERIORATION APPROVAL CONDITIONS

1. The combustion turbines shall be fueled primarily by pipeline quality natural gas. Use of on-road specification, very low sulfur content distillate oil (also called "diesel fuel" as defined in 40 CFR § 80.2(x), referred to as "oil" throughout the remainder of this Approval) is allowed in the event of natural gas curtailment and for maintenance and testing of the oil feed system.

1.1 Sulfur content at the time of purchase of oil to be used as fuel must conform with the then current limit applied to on-road specification oil as defined in the Code of Federal Regulations (at the time of issuance of this permit, defined in 40 CFR § 80.29(a)(i)).

1.2 Cumulative annual use of oil as fuel is not to exceed 15 days or 9,070,560 gallons of oil. Average use of oil as fuel over any ten year rolling period is not to exceed 10 days per year or 6,047,040 gallons per year.

1.3 The oil fuel fired emergency generator shall not exceed 400 kW and shall not be operated in excess of 500 hours per year. The following records regarding the emergency generator shall be maintained current and kept at the facility:

1.3.1 Equipment type, make and model, maximum power input/output.

1.3.2 A monthly log of reason for operation, hours of operation, fuel type, quantity, and sulfur content.

1.4 The oil fuel fired engine for driving the water pump(s) for emergency fire suppression shall not exceed 300 HP and shall be operated only as needed for its maintenance and for emergency fire suppression. The following records regarding this engine shall be maintained current and kept at the facility:

1.4.1 Equipment type, make and model, maximum power input/output.

1.4.2 A monthly log of reason for operation, hours of operation, fuel type, quantity, and sulfur content.

2. When burning natural gas, no HRSG stack exhaust shall contain NO_X emissions that exceed 2.0 parts per million on a dry volumetric basis (ppmdv) over a one hour average when corrected to 15.0 percent oxygen. When burning oil, no HRSG stack exhaust shall contain NO_X emissions that exceed 6.0 ppmdv (one hour average corrected to 15.0 percent oxygen). No HRSG stack exhaust shall exceed daily NO_X emissions of 179 kilograms (395 pounds) when burning natural gas or 538 kilograms (1,185 pounds) when burning oil.

Initial performance and compliance for each turbine shall be determined in accordance with Title 40 CFR Part 60, Subpart GG and Appendix A, Reference Method 20, except that the instrument span shall be 6 ppm or less for testing under gas-firing and 18 ppm or less for testing under oil-firing. An alternate method may be used if approved in advance by EFSEC.

Continuous compliance will be determined by a continuous emission monitoring system (CEMS) that measures and records NO_X and O_2 emissions and exhaust gas flow rate from each exhaust stack. The CEMS shall meet the requirements of Prevention of Significant Deterioration Approval Condition 12.2.

Mass emission rates shall be determined using the appropriate procedures outlined in 40 CFR part 60 Appendix A Method 19. An equivalent mass emission rate test method may be used if approved in advance by EFSEC.

3. When burning natural gas, no HRSG stack exhaust shall contain CO emissions that exceed 2.0 parts per million on a dry volumetric basis (ppmdv) over a one hour average when corrected to 15.0 percent oxygen. When burning oil, no HRSG stack exhaust shall contain CO emissions that exceed 12.0 ppmdv (one hour average corrected to 15.0 percent oxygen). No HRSG stack exhaust shall exceed daily CO emissions of 108 kilograms (240 pounds) when burning natural gas or 655 kilograms (1440 pounds) when burning oil.

Initial performance and compliance for each turbine shall be determined by EPA Reference Method 10 modified to use nondispersive infrared (NDIR) with gas filter correlation, and following the calibration and operation guidelines of EPA Reference Method 6C. The NDIR must have performance specifications allowing a minimum detectable sensitivity of 1 ppmdv with accuracy within +/- 0.5 ppmdv. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition. Mass emission rates shall be determined using the appropriate procedures outlined in 40 CFR part 60 Appendix A Method 19. Equivalent concentration and mass emission rate test methods may be used if approved in advance by EFSEC. An alternate method may be used if approved in advance by EFSEC.

CO emissions from each exhaust stack shall be measured and recorded by CEMS that meet the requirements of Prevention of Significant Deterioration Approval Condition 12.1. Such CEMS shall be used to determine compliance with this Condition.

4. When burning natural gas, no HRSG stack exhaust shall contain SO_2 emissions that exceed 1.0 parts per million on a dry volumetric basis (ppmdv) over a one hour average when corrected to 15.0 percent oxygen. When burning oil, no HRSG stack exhaust shall contain SO_2 emissions that exceed 10.0 ppmdv (one hour average corrected to 15.0 percent oxygen). No HRSG stack exhaust shall exceed daily SO_2 emissions of 41 kilograms (90 pounds) when burning natural gas or 408 kilograms (900 pounds) when burning oil.

Initial performance and compliance for each turbine shall be determined by EPA Reference

Method 6C. The instrument span shall be at maximums of 3 ppm when natural gas is burned, and 30 ppm when oil is burned. All span and calibration gases used shall follow in accordance with the method requirements. An alternate method may be used if approved in advance by EFSEC.

Continuous emission monitoring of SO_2 is not required. Continuous compliance with the limit for each stack shall be by means of fuel sulfur content reporting and fuel flow monitoring to each turbine in accordance with Prevention of Significant Deterioration Approval Conditions 14, 15, and 16, below.

5. When burning natural gas, no HRSG stack exhaust shall contain VOC emissions that exceed 6.0 parts per million on a dry volumetric basis (ppmdv) over a one hour average when corrected to 15.0 percent oxygen. When burning oil, no HRSG stack exhaust shall contain VOC emissions that exceed 10.0 ppmdv (one hour average corrected to 15.0 percent oxygen). No HRSG stack exhaust shall exceed daily VOC emissions of 190 kilograms (420 pounds) when burning natural gas or 269 kilograms (593 pounds) when burning oil.

Initial performance and compliance for each turbine and boiler shall be determined by EPA Reference Methods 18. Mass emission rates shall be determined using the appropriate procedures outlined in 40 CFR part 60 Appendix A Method 19. Equivalent concentration and mass emission rate test methods may be used if approved in advance by EFSEC.

Source testing must be conducted annually for the first three years following initial startup to demonstrate continued compliance. Test methods shall be the same as used for the initial performance test unless approved in advance by EFSEC. Initial startup for each combustion turbine is defined as the time when the first electricity from that turbine is delivered to the electrical power grid. Testing thereafter will be once every three years if the initial performance and subsequent tests satisfy permit limits. Failure of any source test to meet permit limits starts the three year annual test cycle over.

6. No HRSG stack exhaust shall exceed daily filterable PM_{10} emissions of 87 kilograms (192

Review these limits to be sure they're correct. See Eric Hansen's letter to EFSEC, 10/4/00. Esp. temperature considerations.

pounds) per day whether burning natural gas or oil.

Initial performance and compliance with the particulate standard shall be determined by federal Reference Methods 201 or 201A based on the filterable portion ("front half") of the test method capture. Mass emission rates shall be determined using the appropriate procedures outlined in 40 CFR part 60 Appendix A Method 19. Equivalent concentration and mass emission rate test methods may be used if approved in advance by EFSEC.

Source testing must be conducted annually for the first three years following initial startup to demonstrate continued compliance. Test methods shall be the same as used for the initial performance test unless approved in advance by EFSEC. Initial startup for each combustion turbine is defined as the time when the first electricity from that turbine is delivered to the electrical power grid. Testing thereafter will be once every three years if the initial performance and subsequent tests satisfy permit limits. Failure of any source test to meet permit limits starts the three year annual test cycle over.

7. No HRSG stack exhaust shall exceed daily H_2SO_4 emissions of 2.9 kilograms (6.3 pounds) when burning natural gas or 204 kilograms (447 pounds) when burning oil.

Initial performance and compliance with the H_2SO_4 emissions limits shall be determined by EPA Reference Method 8 with incorporation of the procedures given in EPA Reference Method 6, Section 7.3 for elimination of ammonia interference, or an equivalent method approved in advance by EFSEC.

Source testing must be conducted annually for the first three years following initial startup to demonstrate continued compliance. Test methods shall be the same as used for the initial performance test unless approved in advance by EFSEC. Initial startup for each combustion turbine is defined as the time when the first electricity from that turbine is delivered to the electrical power grid. Testing thereafter will be once every three years if the initial performance and subsequent tests satisfy permit limits. Failure of any source test to meet permit limits restarts the three year annual test cycle.

8. All conditions apply except during unit startup and shutdowns. Emissions in excess of the above limits shall be considered unavoidable provided the source reports the exceedance in accordance with Prevention of Significant Deterioration Approval Condition 16, below. The duration of startup or shutdown periods are limited to 3 hours per occurrence, with a maximum of two startups per 24 hour period, and 200 startups per year per turbine.

9. Within 180 days after initial start-up of each turbine, S2GF shall conduct performance tests for NO_X, SO_2, H_2SO_4, CO, VOCs and PM_{10} on each combustion turbine. The performance tests shall be performed by an independent testing firm. A test plan shall be submitted for EFSEC's approval at least 30 days prior to the testing.

10. Sampling ports and platforms shall be provided on each stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR, Part 60, Appendix A Method 20.

11. Adequate permanent and safe access to the test ports shall be provided. Other arrangements may be acceptable if approved by EFSEC prior to installation.

12. Continuous Emission Monitoring Systems

12.1 Continuous emission monitoring systems (CEMS) for CO, shall satisfy the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specifications and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

12.2 CEMS for NO_x, O_2, and exhaust gas flow rate or velocity compliance shall satisfy the requirements contained in 40 CFR 75, Emissions Monitoring.

13. Compliance testing shall be performed for PM_{10}, VOCs, and H_2SO_4 from each stack annually for the first three years following initial startup, and once every 3 years thereafter as long as compliance continues to be demonstrated. Source testing for these parameters is to coincide with the Relative Accuracy Test Audit required for each installed CEMS.

14. CEMS and process data shall be reported in written form to the authorized representative of EFSEC and to the EPA Region X Office of Air Quality at least monthly (unless a different

report form/format, testing and reporting schedule has been approved by EFSEC) within thirty days of the end of each calendar month which shall include but not be limited to the following:

14.1 Quantity and average sulfur content of natural gas burned as substantiated by purchase records and vendor's report. Fuel sulfur content determination shall follow procedures outlined in 40 CFR 60.335(d) and (e).

14.2 Quantity of oil burned for system testing and maintenance, quantity of oil burned because of natural gas curtailment, total quantity of oil burned, total duration of time oil is burned, and sulfur content of all oil purchased (as substantiated by copies of receipts from the oil supplier) since the last report.

14.3 For each stack, the daily average NO_x and CO concentrations, in ppmdv corrected to 15% oxygen .

14.4 For the project, total mass emissions of NO_x and CO on daily (pounds per day) and twelve month moving total (tons per year) bases.

14.5 The duration and nature of any monitor down-time excluding zero and span checks.

14.6 Results of any monitor audits or accuracy checks.

14.7 Results of any required stack tests.

14.8 The above data shall be retained at the S2GF site for a period of five years.

15. The format of the reporting described in Condition 14 shall match that required by EPA for demonstrating compliance with the Title IV Acid Rain program reporting requirements. Pollutants not covered by that format shall be reported in a format approved by EFSEC that shall include at least the following:

15.1. Process or control equipment operating parameters.

15.2. The hourly maximum and average concentration, in the units of the standard, for each pollutant monitored.

15.3. The duration and nature of any monitor down time.

15.4. Results of any monitor audits or accuracy checks.

15.5. Results of any required stack tests.

16. For each occurrence of monitored emissions in excess of the standard, the monthly emissions report (per Prevention of Significant Deterioration Approval Condition 14) shall include the following:

16.1 For parameters subject to monitoring and reporting under the Title IV Acid Rain program, the reporting requirements in that program shall govern excess emissions report content.

16.2 For all other pollutants:

16.2.1. The time of the occurrence.

16.2.2. Magnitude of the emission or process parameters excess.

16.2.3. The duration of the excess.

16.2.4. The probable cause.

16.2.5. Corrective actions taken or planned.

16.2.6. Any other agency contacted.

17. Operating and maintenance manuals for all equipment that has the potential to affect emissions to the atmosphere shall be developed and followed. Copies of the manuals shall be available to EFSEC or the authorized representative of EFSEC. Emissions that result from a failure to follow the requirements of the manuals may be considered proof that the equipment was not properly operated and maintained.

18. Operation of the equipment that has the potential to affect the quantity and nature of emissions to the atmosphere must be conducted in compliance with all data and specifications submitted as part of the PSD/NOC application unless otherwise approved by EFSEC.

19. This approval shall become invalid if construction of the project is not commenced within

eighteen (18) months after receipt of final approval, or if construction of the facility is discontinued for a period of eighteen (18) months, unless EFSEC extends the 18 month period upon a satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2) and applicable EPA guidance.

20. Any activity that is undertaken by S2GF or others, in a manner that is inconsistent with the application and this determination, shall be subject to EFSEC enforcement under applicable regulations. Nothing in this determination shall be construed so as to relieve S2GF of its obligations under any state, local, or federal laws or regulations.

21. The S2GF shall notify EFSEC in writing at least thirty days prior to start-up of the project.

22. Access to the source by EFSEC or the authorized representative of EFSEC shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for revocation of this determination of approval.

This Prevention of Significant Deterioration Permit has been Reviewed by:

_____________________ _____________________
Bernard Brady, P.E. Date
Engineering and Technical Services
Washington Department of Ecology

This Prevention of Significant Deterioration Permit has been Approved by:

_____________________ _____________________
Barbara McAllister Date
Director, Office of Air Quality
U.S. Environmental Protection Agency, Region X

_____________________ _____________________
Deborah Ross Date

Chair
Energy Facility Site Evaluation Council

NOTICE OF CONSTRUCTION APPROVAL CONDITIONS

1. S2GF will comply with all Prevention of Significant Deterioration approval conditions specified above.

2. Total emissions of free NH_3 and ammonium salts measured as NH_3 from each HRSG exhaust stack shall not exceed 10 parts per million on a volumetric basis (ppmdv) over a one hour average when corrected to 15.0 percent oxygen .

   Initial compliance for each turbine shall be determined by Bay Area Air Quality Management District Source Test Procedure ST-1B, "Ammonia, Integrated Sampling", or an equivalent method approved in advance by EFSEC. Source test samples must be unfiltered as taken from each stack. Source testing must be conducted annually for the first three years following initial startup to demonstrate continued compliance. Initial startup for each combustion turbine is defined as the time when the first electricity from that turbine is delivered to the electrical power grid. Testing thereafter will be once every three years if the initial performance and subsequent tests satisfy permit limits. Failure of any source test to meet permit limits starts the three year annual test cycle over.

   Coincident ammonia consumption and fuel use shall be recorded daily and reported monthly. The initial and first three years' source tests shall be used by EFSEC to establish a base line relating the of ammonia-consumption:fuel-use ratio to ammonia emissions. EFSEC or its delegated compliance agent may require ammonia source testing at any time that this relationship indicates ammonia emissions may be exceeding the permit limitation.

3. Opacity from each exhaust stack of the project shall not exceed 10 percent over a six minute average as measured by EPA Reference Method 9, or an equivalent method approved in advance by EFSEC. Opacity from each stack shall be measured and recorded by continuous emissions monitoring systems (CEMS). Each CEMS shall satisfy the

requirements contained in 40 CFR, Part 60, Appendix B, Performance Specification 1 and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

4. All conditions apply except during unit startup and shutdowns. Requirements relative to startup and shutdown shall follow Prevention of Significant Deterioration Approval Condition 8, above.

5. Within 180 days after initial start-up of each turbine, S2GF shall conduct performance tests for NH_3 and opacity on each combustion turbine, to be performed by an independent testing firm. A test plan shall be submitted for EFSEC's approval at least 30 days prior to the testing.

6. Ammonia consumption and fuel use data and opacity observations shall be reported in written form to the authorized representative of EFSEC at least monthly (unless a different report form/format, and reporting schedule has been approved by EFSEC) within thirty days of the end of each calendar month.

7. For each opacity observation in excess of the standard, the monthly report (per Notice of Construction Approval Condition 6) shall include the following:

   7.1 The time of the occurrence.

   7.2 Magnitude of the emission or process parameters excess.

   7.3 The duration of the excess opacity.

   7.4 The probable cause.

   7.5 Corrective actions taken or planned.

   7.6 Any other agency contacted.

8. Prevention of Significant Deterioration Approval Conditions 17 through 22 (operating/maintenance manuals, operation consistent with the PSD/NOC application, construction commencement time limit, enforcement, startup notification, and access to the facility) are also conditions of this Notice of Construction Order of Approval.

This Notice of Construction Approval has been Reviewed by:

Bernard Brady, P.E. | Date
Engineering and Technical Services
Washington Department of Ecology

This Notice of Construction Approval has been Approved by:

Deborah Ross | Date
Chair
Energy Facility Site Evaluation Council

Review table to assure consistent with approval conditions.

APPENDIX A – SUMMARY OF EMISSION LIMITATIONS for PSD EFSEC/00-01

EMISSIONS LIMITS[1]
SUMAS ENERGY 2
GENERATION FACILITY
COMBUSTION TURBINE WITH DRY LOW NO_x TECHNOLOGY, SELECTIVE CATALYTIC REDUCTION, AND OXIDATION CATALYST (PER TURBINE)

Pollutant	Natural Gas Fuel		Oil Fuel		Test Method (or equivalent approved by EFSEC)	Stack Testing or Certification Frequency
	Limit	Averaging Time	Limit	Averaging Time		
NO_x @15% O_2	2.0 ppmdv 395 lb/day	1 hour daily	6.0 ppmv 1,185 lb/day	1 hour daily	RM 20 and CEMs	Initial
CO @ 15% O_2	2.0 ppmdv 10 lb/hr	1 hour 1 hour	12.0 ppmdv 60 lb/hr	1 hour 1 hour	RM 10 and CEMs	Initial
SO_2	1.0 ppmdv 3.75 lb/hr	1 hour	10.0 ppmdv 37.5 lb/hr	1 hour	RM 6 and fuel monitoring	Initial
PM_{10}	192 lb/day	daily	192 lb/day	daily	RM 201 or 201A	Initial, annual for 3 years, once per five years thereafter as long as in compliance
VOC	6.0 lb/hr 420 lb/day	1 hour daily	11.5 lb/hr 593 lb/day	1 hour daily	RM 25A or 25B	Initial, annual for 3 years, once per five years thereafter as long as in compliance
Sulfuric Acid Mist	0.35 lb/hr	1 hour	20.0 lb/hr	1 hour	RM 8	Initial, annual for 3 years, once per five years thereafter as long as in compliance
Ammonia	10 ppmdv	1 hour	10 ppmdv	1 hour	by BAAQMD Source Test Procedure ST-1B	Initial, annual for 3 years, once per five years thereafter as

Review table to assure consistent with approval conditions.

EMISSIONS LIMITS[1]
SUMAS ENERGY 2
GENERATION FACILITY
COMBUSTION TURBINE WITH DRY LOW NO_X TECHNOLOGY, SELECTIVE CATALYTIC REDUCTION, AND OXIDATION CATALYST (PER TURBINE)

Pollutant	Natural Gas Fuel		Oil Fuel		Test Method (or equivalent approved by EFSEC)	Stack Testing or Certification Frequency
	Limit	Averaging Time	Limit	Averaging Time		
						long as in compliance
Opacity	10%	6 minute	10%	6 minute (one daily reading)	RM 9	Initial and 6 month reader certification

1. This table is a summary of the permit's conditions. If there is a conflict between this table and a permit provision, the written permit provision takes precedence.

DRAFT

STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL
FACT SHEET FOR
PREVENTION OF SIGNIFICANT DETERIORATION
Sumas Energy 2 Generation Facility Project
Sumas, Washington
Date

1. INTRODUCTION

1.1 THE PSD PROCESS

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of the Federal Regulations (CFR), 40 CFR Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

The Washington State Energy facility Site Evaluation Council (EFSEC) is the PSD permitting authority for energy facilities greater than 250 MW sited in the state of Washington per Chapter 463-39 of the Washington Administrative Code (WAC).

1.2 THE PROJECT

Sumas Energy 2, Inc. (SE2) proposes to construct and operate the Sumas Energy 2 Generation Facility (S2GF), an electrical generating facility located in Sumas, Washington. SE2 will own and operate S2GF including activities related to obtaining permits and other required approvals. S2GF will be a "merchant" plant, selling power wherever there is a market. The S2GF will be constructed within the City of Sumas, in Whatcom County, Washington. The project site is located in an industrial zone in the City of Sumas, about one-half mile south of the international border and immediately north of the Sumas Cogeneration Company LP No. 1 Generation Facility (SCCLP), a 125 mw power station. The approximately 37-acre property, which includes the site, consists of a 26-acre open field used for agriculture and a 10.6 acre forested wetland, which will be preserved as an element of site planning.

1.2.1 General Description

The S2GF is a combined-cycle facility using natural gas as the primary fuel source. Diesel oil may be used as backup fuel in the event natural gas availability is cut back for industrial sources and for brief system maintenance not to exceed fifteen days per year. The facility design includes two separate but identical combustion turbines, one steam turbine, two generators and two heat recovery steam generators (HRSG). Each HRSG includes a duct burner. Each combustion turbine discharges hot exhaust gases to the HRSG, which produces reheat steam flows to high, intermediate and low pressure sections of the steam turbines. The nominal capacity of each combustion and steam turbine set will be 334.5 MW yielding a total nominal plant capacity of 669 MW.

1.2.2 Fuel Source and Transport

At a 97 percent capacity factor, S2GF will generate approximately 5.7 million megawatt hours of electricity annually and approximately 170 million megawatt hours of electricity over a 30 year operational life. To achieve this generation, S2GF will consume approximately 112 million cubic feet of natural gas daily. The facility will operate at an overall thermal efficiency of 53.5%. The natural gas will be produced in Canada, and delivered through a new 4.5 mile pipeline built parallel to an existing pipeline that delivers natural gas to the existing Sumas Cogeneration Facility. The pipeline border crossing is regulated by the Federal Energy Regulatory Commission (FERC) and will be subject to environmental review (under the National Energy Policy Act) and safety standards (Office of Pipeline Safety). The new 4.5 mile natural gas pipeline, excluding the border crossing, is regulated by EFSEC and will be subject to environmental review under the Washington State Environmental Policy Act (SEPA) and EFSEC rules and regulations.

1.2.3 Power Transmission

The electrical energy produced by S2GF will be transmitted to British Columbia Hydro (BCH) through a new switchyard located at the project site and a 5.9 mile transmission line to the Canadian electric grid at BCH's Clayburn substation located outside Abbotsford, B.C. The transmission line border crossing is regulated by the Federal Energy Regulatory Commission (FERC) and will be subject to environmental review under the National Energy Policy Act. The new 5.9 mile transmission line, excluding the border crossing, is regulated by EFSEC and will be subject to environmental review under the Washington State Environmental Policy Act (SEPA) and EFSEC rules and regulations. This activity has no impact on the PSD permit.

1.2.4 Water Consumption

The City of Sumas will supply the water required by S2GF (maximum 849 gallons per minute). The City of Sumas will not require expansion of any existing water right or a new water right, but may need to drill one or two additional wells to maximize use of the existing rights. The City of Sumas may make some modifications to its water system, such as, interties between the potable and industrial systems and various control valves. The City of Sumas will construct a pipeline to connect potable and industrial water to S2GF. These activities have no impact on this PSD permit.

1.2.5 Waste Water

The average total wastewater discharge from S2GF is expected to be between 166 and 219 gpm. The wastewater sources are cooling tower blowdown, reverse osmosis reject, demineralizer waste, polisher waste, and employee domestic waste. All wastewater will be discharged to the City of Sumas sewer system. S2GF has received a Certificate of Water and Sewer Availability for up to 260 gpm. These activities have no impact on this PSD permit.

1.2.6 Air Pollutant Emissions

1.2.6.1 General Description

The S2GF facility will be a major new source of air pollution because it has the capacity to emit any one of nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), or particulate matter (PM_{10})[1] at more than 100 tons per year. Some of the sulfur dioxide from the facility is expected to convert and hydrolyze to sulfuric acid mist[1]. Emissions of NO_x, CO, VOCs, PM_{10}, SO_2/SO_3, and sulfuric acid mist at these levels are subject to regulation under the PSD program.

S2GF will also emit toxic air pollutants. The sulfuric acid mist included as a criteria pollutant, above, is also a toxic air pollutant. Some of the unburned hydrocarbons[2] and excess ammonia from NO_x reduction are the other toxic air pollutants that will be emitted by S2GF. Toxic air pollutants are regulated under Chapter 173-460 WAC (new source review regulations).

1.2.6.2 National Ambient Air Quality Standards

The United States Environmental Protection Agency (EPA) and the Washington Department of

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[1] Potential to emit:

NO_x: 156 tons per year (2 ppmdv on gas, 6 ppmdv on oil)
CO: 106 tons per year (2 ppmdv on gas, 12 ppmdv on oil)
SO_x: 45 tons per year (<1 ppmdv on gas, 10 ppmdv on oil) if the full fifteen permitted days of annual oil-firing is realized. In any year in which no oil is used as fuel, sulfur oxide emissions should not exceed 11 tons.
VOCs: 156 tons per year (6 ppmdv on gas, 10 ppmdv on oil)
PM_{10}: 223 tons per year (filterable and condensable)
H_2SO_4 mist: 9.3 tons per year (13.5% molar conversion SO_2 to SO_3, fully hydrated) if the full fifteen permitted days of annual oil-firing is realized. In any year in which no oil is used as fuel, sulfuric acid mist emissions would not exceed 3 tons per year.

[2] Acrolein, benzene, and polycyclic aromatic hydrocarbons among others.

Ecology (Ecology) have established ambient air quality standards (NAAQS and WAAQS, respectively). "Primary" standards apply to populated areas (Class II areas), and are designed to protect human health and safety. "Secondary"standards apply to sensitive areas (Class I areas), and are designed to protect soils and vegetation. The site of the proposed project is within a Class II area that is in attainment with regard to all pollutants regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is 55 kilometers (km.) from the nearest Class I Area, North Cascades National Park, within 175 km. of four other Class I areas (Alpine Lakes Wilderness, Glacier Peak Wilderness, Olympic National Park, and Pasayten Wilderness), and within one-half mile of the Canadian border. Impacts of S2GF on visibility, soils, and vegetation in Class I areas are discussed in Section 4.1, below.

Potential impacts are tested by modeling the predicted increase in ambient concentrations of the pollutants (NO_x, CO, SO_x, and PM_{10}) emitted by the new source, and comparing them to a maximum that is allowed (Class I or II increment). EPA has established no significant ambient impact concentration for ozone (VOCs). However, VOC emissions from S2GF are expected to be high enough that an ambient impact analysis is required for ozone. Modeled pollutant concentration increases were determined for S2GF alone for Class I areas within 175 kilometers and in combination with other nearby pollutant sources for the Class II area within 50 kilometers. The modeling indicated that pollutant emissions from S2GF would not cause an ambient concentration increase that exceeds an allowable increment. The ozone impact analysis performed to evaluate the contribution of the project in the adjoining Lower Fraser Valley indicated that "increases in ozone episode intensity ... will be small and localized"[3]

1.2.6.3 Canadian National Ambient Air Quality Objectives

Because the proposed facility is so close to the U.S. – Canada border, SE2 analyzed the pollutant emission impact of S2GF relative to the Canadian National Ambient Air Quality Objectives as well as the objectives established by British Columbia and the Greater Vancouver Regional District (GVRD). Whereas the NAAQS and WAAQS establish limits that must not be exceeded by a proposed new source in the State of Washington, the analogous Canadian "objectives" are guidelines intended to assist Canadian federal, provincial, and local government in decision-making. There are three levels of Canadian objectives:

- Maximum desirable: Long-term goals that provide a basis for an anti-degradation policy for the unpolluted parts of Canada and for continuing development of control technology. The related pollutant concentrations are roughly equal to one-third to one-half the NAAQS.

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[3] Di Cenzo, Colin and Potter, Joanne, A Numerical Simulation of Impacts on Ambient Ground level Ozone Concentrations from the Proposed Sumas Energy 2, Inc. Power Generation Facility, Report 2000-001, Atmospheric Sciences Section, Environment Canada (January 31, 2000, Vancouver, BC), http://www.efsec.wa.gov/Sumas2/s2revjan00/s2gf_ozone.pdf

- Maximum acceptable: Intended to provide adequate protection against adverse effects on humans and the environment. The related pollutant concentrations are roughly equal to the NAAQS.

- Maximum tolerable: Time-based concentrations beyond which immediate action is required to protect public health.

Whether firing natural gas (the preponderant condition) or low-sulfur oil (allowed only under natural gas curtailment), the modeled criteria pollutant concentrations of S2GF are below the Maximum Desirable Air Quality Objective except for "24 hour suspended particulate". GVRD records indicate there are times when the background PM_{10} concentration in the area of Abbotsford, British Columbia is near or above the GVRD Maximum Desirable Air Quality Objective. If S2GF were to be burning oil, the addition of its PM_{10} emissions could contribute to or exacerbate an exceedance. However, GVRD staff indicated that such high PM_{10} periods rarely occur during the winter. For example, The GVRD Maximum Desirable Objective was exceeded only four times from 1994 through 1998 during the November through February period[4]. S2GF may burn oil for extended periods only during the winter[5]. Consequently, it is unlikely that PM_{10} emissions from S2GF will cause an exceedance of the GVRD Maximum Desirable Objective.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1 DEFINITION and POLICY CONCERNING BACT

All new sources are required to utilize Best Available Control Technology (BACT). BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost effectiveness, economic, energy, environmental and other impacts (40 CFR 52.21(b)(12)).

The "top down" BACT process starts by considering the most stringent form of emissions reduction technology possible, then tries to prove it technically infeasible or not economically justifiable. If proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology cannot be defeated, then it is determined to be BACT.

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[4] Electronic mail communication from Domenic Mignacca (Air Quality Analyst, GVRD) to Bernard Brady (Environmental Engineer, Ecology), June 20, 2000

[5] Apart from approximately bi-weekly, fifteen minute or less system maintenance firings. Such brief oil-firing periods have no measurable impact on regional air quality.

2.2 BACT ANALYSIS FOR CRITERIA POLLUTANTS

2.2.1 NITROGEN OXIDES CONTROL

Federal new source performance standards (NSPS) for stationary gas turbines (40 CFR 60.330 Subpart GG) limit nitrogen oxides from the proposed Westinghouse turbines to 159 parts per million by dry volume (ppmdv) corrected to 15 percent oxygen. Sulfur oxide emissions are limited to 150 ppmdv, and the use of fuel containing more than 0.8 percent sulfur is prohibited. Application of the BACT process reduces limits much further. Federal new source performance standards for electric utility steam generating units (40 CFR 60.40a Subpart Da) apply to the gas-fired duct burners in the proposed S2GF system. Under this NSPS, particulate, sulfur dioxide and nitrogen dioxide emissions from the duct burners are limited to 0.03, 0.02, and 0.02 pounds per million Btu, respectively. At the proposed maximum firing rate of 466 million Btu per hour, these limits translate to 14 pounds per hour of particulate matter and 93 pounds per hour each of SO_2 and NO_x. Imposition of BACT lowers the permitted levels of particulate matter, SO_2 and NO_x substantially below those required under NSPS.

The following control technologies were considered for NO_x reduction:

- SCONOx
- Selective Catalytic Reduction (SCR)

Because the applicant proposed to use Selective Catalytic Reduction to achieve the same NO_x reduction as would be guaranteed by SCONOx, these control technologies are of equal stringency. The order of their discussion is arbitrary.

2.2.1.1 SCONOx:

SCONOx is a relatively new NO_x emissions reduction technology. NO_x is reduced by an absorption-reaction mechanism. NO_x is absorbed into a potassium carbonate (K_2CO_3) layer on the catalyst matrix surface. The NO_x reacts with the K_2CO_3 to form potassium nitrate (KNO_3). Eventually, the K_2CO_3 is exhausted. The catalyst-absorbent bed is then taken off-line for regeneration with either natural gas or hydrogen, depending on the system design operating temperature. In the regeneration process, the nitrate is reduced to nitrogen and exhausted up the stack while the KNO_3 is converted back to K_2CO_3. The catalyst-absorbent bed is then cycled back into NO_x reduction service[6].

The SCONOx vendor will guarantee NO_x emissions not to exceed 2 ppmdv when natural gas is

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[6] Reyes, Boris, SCONOx Catalytic Absorption System, Goal Line Environmental Technologies, 11141 Outlet Dr., Knoxville, TN (December 8, 1998)

burned. SCONOx did not submit a guarantee of performance in the event low-sulfur oil is burned. Nonetheless, this analysis assumes the same performance would be achieved by SCONOx as is expected under selective catalytic reduction (SCR), namely, 6 ppmdv NO_x when burning oil. SE2 is willing to accept a 2 ppmdv NO_x emission limit (natural gas firing) if they are permitted to install the SCR process. Nonetheless, the SCONOx process still has a potential advantage because it accomplishes NO_x reduction without the use and attendant release of ammonia in the facility's emissions. Ammonia releases associated with SCR are discussed further in Section 3.2. In addition, SCONOx will reduce emissions of both carbon monoxide (CO) and volatile organic compounds (VOCs) without additional control equipment. This capability for multiple pollutant reduction complicates the BACT analysis process. To account for this, SCONOx will be considered sequentially and incrementally for each pollutant as well as in-toto versus the proposed SCR plus CO-combustion catalysis.

The first commercial-size SCONOx system was installed in May 1995 at the Sunlaw-U.S. Growers 30-megawatt power plant in Vernon, CA. A second SCONOx unit, with improved economic and operational design, was installed in December 1996 at Sunlaw's other 30 megawatt power plant, Federal Cold Storage. The SCONOx pollution control system has been operating satisfactorily in these plants since startup. These are the only two combined-cycle power turbine facilities operating using SCONOx at this time. In early 1999, Goal Line Environmental Technologies, Inc. announced that it would provide SCONOx systems sufficient to control pollutant emissions from power turbines having up to 300 MW capacity. There is one proposed facility: an air permit application submittal by PG&E to use SCONOx on its new 510 MW Otay Mesa power plant[7] in San Diego County, CA. If built, this facility will be in an ozone nonattainment area.

The fact that SCONOX has been operating satisfactorily for several years in two facilities is strong evidence that the process is technically feasible, at least for relatively small power turbine systems. However, application to SE2 would involve a ten-fold scale up. From an engineering perspective, this is generally considered to be a serious leap in demonstration of technical feasibility. Notwithstanding Goal Lines' faith in SCONOx, it is worthwhile to consider that the proposed PG&E plant would be in an ozone nonattainment area. Proposed commercial facilities that will emit significant amounts of NO_x and/or VOCs in ozone nonattainment areas must install pollution control systems meeting the criteria for the "Lowest Available Emission Rate". These criteria are more stringent than for the same kind of facility proposed to be built in an attainment area. They can direct the control requirement toward technologies that are less thoroughly demonstrated than generally required for BACT. At best, given the level of uncertainty, SCONOx may considered to be marginally technically feasible. Cost data submitted to SE2 by SCONOx vendor (ABB-Alstrom Power, www.abb-alstrom-power.com) indicates that annual costs would be $4,538,128 per turbine or $5,175 per ton of NO_x reduction under fully permitted plant

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[7] Two turbine trains.

operation.

2.2.1.2 Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) is an alternative to SCONOx for NO_x emission control. SCR is the injection of ammonia into the HRSG exhaust in the presence of oxygen and a platinum, vanadium or titanium catalyst to reduce nitrogen oxides to nitrogen and water. The amount that emissions can be reduced is a function of the catalytic reactor design and level of ammonia feed. SE2 proposed that using SCR to reduce NO_x emission concentrations to the same degree as SCONOx should be BACT for NO_x. (from 25 ppmdv uncontrolled to 2 ppmdv, gas-firing, and 42 ppmdv uncontrolled to 6 ppmdv, oil-firing). Since the same level of control is proposed whether SCONOx or SCR are used, SCR is of equal stringency to SCONOx for the S2GF BACT analysis.

SCR has been applied successfully for NO_x emission control since at least the late 1980's. Its technical feasibility is above question. Consequently, the choice between SCONOx and SCR rests heavily on cost effectiveness. Cost data submitted by SE2 and modified for consistency with the EPA control cost analysis guidance[8] indicates that annual costs for SCR would be $1,655,776 per turbine or $1,888 per ton of NO_x reduction under fully permitted plant operation[9].

Although SCR has a significantly lower cost than SCONOx for the same performance, **SCONOx must be considered for its multi-pollutant reduction capabilities before making a final BACT determination.** To do this, the difference between SCR and SCONOx costs for NO_x emission control will be applied to carbon monoxide and VOC control successively, below.

2.2.2 CARBON MONOXIDE CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for CO or VOCs from gas turbines.

Control Options Considered in order of stringency:

- SCONOx (90% carbon monoxide reduction)

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[8] OAQPS Control Cost Manual (Fourth Edition, 1990, with supplements)

[9] Precise verification of total installation and operating costs for SCR systems is difficult. Most of the installations reported in the OAQPS BACT/LAER Clearinghouse accepted SCR as "top case BACT" in their applications. BACT cost effectiveness estimates are not required in these cases. However, the cost estimate used in this (S2GF) BACT analysis compares well with the cost estimates for the Satsop Project (Elma, WA), Chehalis Generation Facility (Chehalis, WA), Newark Bay Co-generation (Newark, NJ), and Hermiston Generating Co. (Hermiston, OR).

- Catalytic Oxidation (80% carbon monoxide reduction)

2.2.2.1 SCONOx

The most stringent means to control carbon monoxide (CO) is SCONOx. As mentioned above, SCONOx reduces CO emissions at the same time as it reduces NO_x. SCONOx reduces CO emissions by catalytically oxidizing the CO to carbon dioxide (CO_2). If SCONOx were to be chosen as the emission control technology, CO emissions should be reduced from 10 ppmdv uncontrolled to 1 ppmdv when firing natural gas. As mentioned above, SCONOx did not submit a guarantee of performance in the event low-sulfur oil is burned. Nonetheless, this analysis assumes the same performance would be achieved by SCONOx as is expected under selective catalytic reduction (SCR), namely, 12 ppmdv CO when burning oil. This is a 211 ton per year CO reduction per turbine at fully permitted operation. As mentioned above, the SCONOx process is substantially more expensive than the SCR process for NO_x reduction. Due to SCONOx' ability to reduce multiple pollutants, the excess cost can be applied to a CO reduction BACT cost effectiveness determination. The excess in annual cost of SCONOx over SCR for NO_x reduction is $2,882,352. This is $13,660/ton applied as the CO reduction cost.

Recent BACT cost effectiveness analyses for CO reduction for electric power plants indicate CO controls have been imposed up to a cost of about $2,000/ton. This does not represent a firm ceiling to justifiable CO reduction costs. Nonetheless, few would argue that imposing a control cost almost seven times the previous maximum would be reasonable.

2.2.2.2 Catalytic Oxidation

The next most stringent means to control CO is catalytic oxidation. The hot HRSG exhaust gas passes through a catalyst section where oxygen in the gas stream is reacted with CO to produce CO_2. This is a well-established technology that is of unquestionable technical feasibility. SE2 proposed using catalytic oxidation to reduce CO emissions from 10 ppmdv uncontrolled to 2 ppmdv, gas-firing, and from 30 ppmdv uncontrolled to 12 ppmdv, oil-firing. This is a 189 ton per year CO reduction per turbine at fully permitted operation. SE2 estimated the annual cost per turbine to be $418,379, or $2,210/ton CO reduction. Additionally, some VOCs may be destroyed, and a portion of the SO_2 is oxidized to acid mist (SO_3, H_2SO_4) and sulfate compounds. This will be discussed further in sections 2.2.3 and 2.2.5, below.

Although catalytic reduction has a significantly lower cost than SCONOx for CO emission reduction, **SCONOx must still be considered for its ability to remove the additional 1 ppmdv of CO and 90% of the volatile organic compounds (VOCs) before making a final BACT determination.** To do this, the difference between SCR and SCONOx costs for CO emission control to 2 ppmdv will be applied to the additional control, below.

2.2.3 VOLATILE ORGANIC COMPOUND CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for volatile organic compounds (VOCs) from gas turbines.

Control Options Considered in order of stringency:

- SCONOx (90% VOC reduction)
- Catalytic Oxidation (80% VOC reduction)
- Natural gas as the primary fuel and good combustion practice

2.2.3.1 SCONOx

The most stringent means to control volatile organic compounds (VOCs) is SCONOx. As mentioned above, SCONOx reduces VOC emissions at the same time as it reduces NO_x and CO. SCONOx reduces VOC emissions by catalytically oxidizing the VOCs to carbon dioxide (CO_2). If SCONOx were to be chosen as the emission control technology, VOC emissions should be reduced from 6 to 8 ppmdv uncontrolled to 0.6 to 0.8 ppmdv[10]. This is a 70.2 ton per year VOC reduction per turbine at fully permitted operation. As mentioned above, the SCONOx process is substantially more expensive than the SCR plus CO-oxidation process for NO_x and CO reduction. Due to SCONOx' ability to reduce multiple pollutants, the excess cost can be applied to a BACT cost effectiveness determination for VOC (and the additional 1 ppmdv or 22 TPY CO) reduction. The excess in annual cost of SCONOx over SCR plus CO-oxidation for NO_x and CO reduction is $2,463,973 per turbine. This is $26,724/ton applied as the VOC and remnant CO reduction cost.

A search of the EPA's BACT/LAER clearinghouse data indicates VOC emission control technology for BACT has not been imposed at costs exceeding about $3,300/ton VOC reduction. This does not represent a firm ceiling to justifiable VOC reduction costs. Nonetheless, few would argue that imposing a control cost over eight times the previous maximum would be reasonable.

2.2.3.2 Catalytic Oxidation

SE2 has agreed to install an oxidation catalyst on each HRSG exhaust. An oxidation catalyst system can reduce both carbon monoxide CO) and volatile organic compounds (VOCs). However, SE2 indicated that these are competing options. Pollutant removal depends on where the catalyst system is placed in the exhaust system. SE2 focused on CO reduction, and made no claim of VOC reduction except for formaldehyde (CH_2O). It is generally accepted that because CH_2O is a simple and partially oxidized organic compound it will oxidize at about the same time

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[10] Depending on whether firing natural gas or low-sulfur oil.

and to the same degree as CO[11].

It is technically feasible for SE2 to place an additional catalytic oxidation unit in the exhaust system focusing on VOC reduction. SE2 did not present, propose, or analyze this possibility. However, it is possible to extrapolate a corresponding BACT cost effectiveness estimate from the CO catalytic oxidation analysis.

The cost of an additional unit should be very similar to the CO catalytic oxidation unit because cost is primarily dependent on the volume of exhaust gas, and not the amount of pollutant. Consequently, a reasonable estimate for the additional unit would be about $418,379 per year per turbine. An 80% reduction in VOC emissions would be 62.4 TPY per turbine, yielding a BACT cost effectiveness of $6,704/ton VOC reduction. As mentioned in section 2.2.3.1, a search of the EPA's BACT/LAER clearinghouse data indicates VOC emission control technology has not been imposed at costs exceeding about $3,300/ton VOC reduction. EFSEC believes that imposing a control technology that is twice as costly as the previous maximum is not justifiable. Consequently, **EFSEC concludes that a second catalytic oxidation system is not justified for VOC emission reduction.**

2.2.3.3 Natural gas as the primary fuel and good combustion practice

This is the "no further control" option. The control technology discussion in sections 2.2.3.1 and 2.2.3.2 are based on possible volatile organic compound emission reductions from this level. No feasibility consideration is necessary. There is no BACT cost effectiveness to consider. By default, **EFSEC concludes that natural gas as the primary fuel and good combustion practice is BACT for VOC emission control**.

2.2.4 BACT cost effectiveness considered in terms of total pollutant removal:

The following control technologies were considered in terms of total pollutant reduction:

- SCONOx

As discussed in the previous paragraphs, SCONOx has the capability of reducing NO_x, CO, and VOCs simultaneously. The total expected pollutant reduction would be 1,157 tons per year per turbine. The annual operating cost per turbine is expected to be $4,538,128. So, the BACT cost effectiveness is $3,922 per ton total pollutant removal. Analysis of the data in EPA's

[11] Roy, Sims; Emission Standards Division, Combustion Group, US Environmental Protection Agency Memorandum to Docket A-95-51; *Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines*, December 30, 1999 (http://www.epa.gov/region07/programs/artd/air/nsr/nsrpg.htm)

BACT/LAER clearinghouse indicate that for multiple pollutant removal systems, the maximum combined BACT cost effectiveness is around $2,500 per ton. Considering the marginal technical feasibility of the SCONOx process, EFSEC concludes that the disparity between historical, combined pollutant BACT cost effectiveness and the BACT cost for SCONOx is unreasonably high. **EFSEC concludes that considering total pollutant removal capability does not justify the SCONOx process for application to SE2.**

2.2.5 BACT Determination for NO_x, CO, and VOCs:

The above analysis demonstrates that at this time the SCONOx process is marginally technically feasible as an emission control technology for power turbines, and is unjustifiably expensive whether considered for its multi-pollutant reduction capability from a sequential or total perspective.

EFSEC agrees with SE2's evaluation and determines BACT for NO_x to be selective catalytic reduction. NO_x emissions will be limited to a one hour average concentration 2 ppmdv when burning natural gas and 6 ppmdv when burning low-sulfur oil, corrected to 15.0 percent oxygen. NO_X emissions and exhaust gas flow rate or velocity from each exhaust stack shall be measured and recorded by a continuous emission monitoring system that meets the requirements of 40 CFR 60, Appendix F.

EFSEC agrees with SE2's evaluation and determines BACT for CO to be catalytic oxidation. CO emissions will be limited to a one hour average concentration 2 ppmdv when burning natural gas and 12 ppmdv when burning low-sulfur oil, corrected to 15.0 percent oxygen. Each stack will be equipped with continuous CO monitoring that meets the requirements of 40 CFR 60, Appendix F.

EFSEC agrees with SE2's evaluation and determines BACT for VOC to be use of natural gas as the primary fuel and good combustion practice. Volatile organic compound (VOC) emissions from each HRSG exhaust stack shall not exceed 3.5 pounds per hour when firing natural gas under base load without duct firing, 17.5 pounds per hour when firing natural gas under base load with duct firing, or 24.7 pounds per hour when firing low-sulfur oil.

2.2.6 SULFUR DIOXIDE CONTROL

Federal new source performance standards (40 CFR 60.330 Subpart GG) for turbines limit sulfur dioxide (SO_2) emissions to 150 ppmdv at 15 percent O_2 and by limiting sulfur content of the natural gas to 0.8 percent by weight.

SE2 proposes and **EFSEC agrees with S2GF that using only pipeline quality natural gas and**

on-road specification, low-sulfur distillate oil[12] with less than 0.05% sulfur as fuel constitutes BACT for SO_2 control. SE2 will be using natural gas containing very low sulfur levels (less than 1 ppmdv). The permitted SO_2 emission level is one ppmdv when firing natural gas and 10 ppmdv when firing oil (measured at 15% oxygen). Sulfur content of the fuel will be monitored in accordance with 40 CFR 60.334(b), and in accordance with 40 CFR 75 Appendix D.

2.2.7 SULFUR TRIOXIDE AND SULFURIC ACID CONTROL

SE2 estimates that 13.5% of the SO_2 will oxidize to sulfur trioxide (SO_3) as a combined result of turbine combustion equilibria and the post-oxidation catalytic system (CO control)[13]. SE2 proposes and **EFSEC agrees with S2GF that using only natural gas and on-road specification, low-sulfur distillate oil as fuel constitutes BACT for SO_3 control.** Virtually all the SO_3 should hydrolyze by reaction with water vapor in the exhaust gas to sulfuric acid. The permitted sulfuric acid emission level from each HRSG stack is 18.6 pounds per day when firing natural gas and 186 pounds per day when firing oil. Because S2GF will use ammonia injection to control NO_x, most if not all of the sulfuric acid will be neutralized to ammonium sulfate and bisulfate in the condensing exhaust plume.

2.2.8 PARTICULATE AND PM_{10} CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for particulate or for particulate matter less than 10 microns (PM_{10}) emitted from gas turbines.

SE2 proposes and **EFSEC agrees with S2GF that good combustion practice, using only natural gas and on-road specification, low-sulfur distillate oil with less than 0.05% sulfur as fuel, and minimizing oil-firing constitute BACT for PM_{10} emissions.** Filterable PM_{10} emissions are limited to 192 pounds per day per stack as demonstrated under maximum load conditions.

3. AMBIENT AIR QUALITY ANALYSIS

3.1 REGULATED POLLUTANTS

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[12] Currently, on-road specification, low-sulfur oil is limited to 0.05% sulfur. By 2007, further regulation is expected to lower the sulfur limit substantially. See Proposed Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, EPA Regulatory Announcement, EPA 420-F-00-022 (May 2000)

[13] Data supplied to S2GF by Nooter-Erickson, the vendor of the heat recover steam generator and CO-combustion catalytic systems.

PSD rules require an ambient air quality impacts assessment (40 CFR Part 52.21) from any facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to maximum allowable increments prevents significant deterioration of air quality.

SE2 submitted a preliminary modeling analysis to EFSEC proposing the modeling approach. EFSEC agreed with the analysis and determined that pre-construction monitoring would not be required. The 1985-89 surface observations at Abbotsford Airport[14] provided the necessary meteorological data for the modeling exercise. Monitoring data from Abbotsford for 1996-98 provided the estimates for background criteria pollutant concentrations[15]. SE2 applied this data along with the anticipated pollutant emissions in a sophisticated and generally accepted model to determine the air quality impact of the proposed facility[16].

Ambient impact analysis indicates that all regulated pollutants are well below ambient air quality standards established to protect human health and welfare.

3.2 TOXIC AIR POLLUTANTS

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". The TAPs are evaluated for both acute (24 hour) and chronic (annual) effects. The quantities of all TAPs to be emitted from the turbines and duct burner were estimated and modeled to determine their maximum ambient concentrations. These maximum ambient concentrations were compared to the respective acceptable source impact levels (ASIL). These ASILs are not health effect levels, but thresholds that, if exceeded, indicate the need for further investigation.

S2GF is expected to emit small quantities of organic TAPs as products of incomplete combustion and metallic TAPs that were impurities in the fuel. As discussed in Section 2.2, EFSEC determined that BACT for the criteria pollutants for S2GF is SCR, CO-catalytic combustion, good combustion practice, and use of low-sulfur fuel. Under this control system, when burning gas at full design rate, ambient concentrations of all of the TAPs were found to be well below the ASILs. On the average, anticipated TAP emissions are about 3% of the respective ASILs.

When burning oil at full design rate in both turbines, all the effects of acute TAPs except sulfuric

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[14] These data are collected by the Canadian Climate Service using instruments and methods similar to the National Weather Service at United States airports.
[15] Collected by the Greater Regional Vancouver District
[16] CALPUFF modeling system, Phase 2 Summary Report and Recommendations for Modeling Long Range Transport and Impacts, EPA-454/R-98-019, Interagency Workgroup on Air Quality Modeling, USEPA Office of Air Quality Planning and Standards, Research Triangle Park, NC27711 (1998)

acid mist and all the chronic effects are well below the ASILs (average about 5% of the respective ASIL). The toxic effect of sulfuric acid mist (an acute TAP evaluated for 24 hour average ambient concentration) is less than, but very close to the ASIL. This is mitigated by two factors: First, SE2 agreed that oil will only be burned when natural gas is curtailed and for very brief maintenance checks (about fifteen minutes every two weeks). EFSEC has been unable to find a record of any curtailments caused by a natural gas shortage in the last 10 years, and gas is expected to be plentiful for the foreseeable future. Second, much of the sulfuric acid mist will react in the condensing exhaust plume with the excess ammonia from the SCR NO_x control to form the nontoxic sulfate and bisulfate ammonium salts.

Ammonia emissions from S2GF deserve special discussion. Ammonia is a TAP defined in WAC 173-460[17]. Ammonia is released from the SCR process because a slight excess is required to force NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip." SCR manufacturers guarantee that this leakage of unreacted ammonia will be less than 10 ppmdv. Recent operating experience indicates that it may be as low as one to five ppmdv[18], at least in the first several years of the plant's operation. However, while technically feasible, the ammonia slip required to achieve the 2 ppmdv limit for S2GF is not well-documented. Limiting S2GF to an ammonia emission limit that is lower than the SCR vendor guarantee would not be reasonable unless justified by an attendant environmental risk. At 10 ppmdv, the maximum modeled ammonia concentration outside the boundary of S2GF is about 6% of the ASIL; i.e., well below concern. This concentration is also less than one-five hundredth the odor threshold and one three thousandth the acute toxicity level. Consequently, **EFSEC concludes that a 10 ppmdv ammonia emission limit for S2GF does not threaten human health.** Nonetheless, there is one more consideration relative to ammonia as a TAP.

Prior to the commercialization of the SCONOx process, SCR was unquestionably BACT. As discussed in Section 2, SCONOx has not passed the economic test of BACT cost effectiveness for criteria pollutant control for S2GF. However, because the use of SCONOx would eliminate ammonia emissions, Chapter 173-460 WAC requires that SCONOx be considered as a possibility for BACT for TAPs (T-BACT). By substituting a reasonable BACT cost effectiveness for VOC reduction for the calculation outlined in Section 2.2.3.1, the excess SCONOx cost can be applied to evaluate the cost effectiveness for ammonia reduction. For the purpose of this exercise, we impose a $4,000 per ton ceiling for the VOC and extra CO reduction. This leaves an annual cost

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[17] Ammonia is also a hazardous material to transport and store on site. However, S2GF will be using aqueous ammonia which is much less hazardous, albeit more expensive than liquefied ammonia gas.

[18] For example: PGE Coyote Springs in Morrow County, Oregon and Hermiston Generating Project, Umatilla County, Oregon operate at less than 4.4 ppmdv ammonia slip with NO_x below 4 ppmdv. Also see Selective Catalytic Reduction Control of NO_x Emissions, prepared by the Institute of Clean Air Companies, 1660 L St., Suite 1100, Washington, D.C., page 12 (1997).

per turbine of $2,095,170 for SCONOx that can be applied as an ammonia reduction cost. For the 136 ton per year ammonia reduction per turbine, this is $15,405/ton. Since there is no apparent health risk from the ammonia emissions, this is not a justifiable control cost. Consequently, **EFSEC agrees with SE2's evaluation and determines T-BACT for ammonia emissions is SCR with an emission limit of 10 ppmdv.**

Ammonia is a Washington State toxic air pollutant (TAP) by itself, and also combines with hydrated sulfur and nitrogen oxides to form the corresponding salts. Environmentally these salts are particulates that contribute to visible haze. Inevitably, these salts deposit in soils, and may cause excessive nitrogenous enrichment. This is discussed further below in Section 4.1.2.

4. AIR QUALITY RELATED VALUES

4.1 Class I area impacts

The PSD regulations require an evaluation of the effects of the anticipated emissions on visibility from any Class I area and the impact of emissions on soils and vegetation. Impacts were evaluated for the five established and one proposed Class I areas within 175 km. At the recommendation of the federal land managers, SE2 used CALPUFF (*op. cit.*) to analyze the possible impacts on visibility and deposition discussed below.

4.1.1 Visibility

The federal land managers suggested a 5% reduction in visibility as the significance threshold. The regional haze impact assessment indicated that any time S2GF is operating on natural gas, visibility impacts on Class I areas are less than this significance level. On winter days with certain temperature, wind, and humidity conditions, if S2GF were to be operating on oil, visibility in Olympic National Park, North Cascades National Park, and Mt. Baker Wilderness could be reduced by up to 7 to 8 %. This is slightly higher than the 5% significance threshold. However, it appears this level of visibility impact is likely only when area temperatures are in the 30° F. to 40° F. range. These are the most common daytime winter temperatures for the area. S2GF will be using oil only during natural gas curtailment, and curtailment is likely only during much colder periods. In other words, S2GF is unlikely to be using oil as fuel when weather conditions are susceptible to attendant visibility impact effects. Consequently, visibility impacts above 5% are unlikely. **EFSEC concludes that S2GF is unlikely to have a significant impact on visibility in Class I areas.**

Due to its proximity to the U.S.-Canada international border, S2GF may have visibility effects on Canadian areas with analogous standing to U.S. Class I areas. Canada has not specifically designated such areas. However, Pacific Rim, Mount Revelstoke, Glacier, Yoho, and Kootenay are Canadian national parks located in British Columbia relatively near the international border.

For the purpose of considering S2GF's visibility impact on sensitive Canadian areas, these may be considered surrogates for U.S. Class I areas. All but Pacific Rim National Park are located well-East of Sumas, near the projection of the Washington-Idaho border. In winter, when oil-firing is possible, visibility impacts from S2GF concentrate primarily to the west. The dispersion modeling results indicate visibility impacts from S2GF on these national parks to the east will be very low. Pacific Rim National Park is about half-again farther from S2GF than is Olympic National Park. The dispersion modeling results indicate the visibility impact from S2GF on Pacific Rim National Park will be less than half the impact on Olympic National Park, i.e. less than a 5% visibility reduction. **EFSEC concludes that S2GF is unlikely to have a significant impact on visibility in national parks in British Columbia.**

British Columbia's Ministry of Environment requested that SE2 estimate visibility impacts on lines-of-sight surrounding Abbotsford, B.C. Abbotsford is analogous to a Class II area in the U.S. The following conclusions are based on the data provided by SE2 in response to that request[19]. If SE2 is burning oil, there is as much as a 25% chance that visibility from Abbotsford along various lines-of-sight 6 to 43 kilometers long may be perceptibly reduced. As in the discussion, above, concerning Class I areas, "perceptible" is defined as a 5% or greater visibility reduction. If S2GF were to use all the permitted fifteen days per year of oil-firing, S2GF would be a significant contributor to two or three days of perceptible visibility reduction. During gas-firing, regardless of the season, there is less than a ten percent chance that S2GF will contribute significantly to perceptible visibility reduction along lines-of-sight from Abbotsford.

4.1.2 Deposition

Air concentrations of ozone, nitrogen oxides, and sulfur oxides and fallout from derivatives have the potential to impact flora and fauna in the area surrounding an emissions source. SE2 modeled the maximum increases in air concentrations of the acid precursor pollutants, NO_x and SO_2, caused by S2GF. They do not exceed 0.2% of the US Forest Service (USFS) criteria for sensitive specie protection or 3% of the Class I increments on 24 hour or annual bases. Ozone is a derivative of complex reactions of VOCs and NO_x from S2GF and all other sources including natural ones. Because of this complexity, reliable models for predicting ozone concentrations caused by S2GF are not available. However, VOC emissions from S2GF are about the same as the NO_x emissions. It is reasonable to conclude that the ultimate ozone impact attributable to S2GF relative to all other emissions sources would be similar to the NO_x impact, i.e., very low. Modeled annual surface deposition rates of nitrogen and sulfur do not exceed 0.05% of the USFS/National Park Service criteria for soil and aquatic protection. Maximum ozone, nitrogen

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[19] Eaden, David N. (Vice President Engineering and Construction, Sumas Energy 2, Inc.) to Wallis, Hu (Manager, Air Quality Assessment, Ministry of Environment, Lands and Parks, Victoria, B.C.), "MFG Responses to MELP Comments of February 23, 2000", April 18 2000, pages 38-52

oxides, and sulfur oxides concentration increases and surface deposition caused by S2GF in British Columbia's national parks should be even lower than estimated for the U.S. Class I areas. Surface deposition of pollutants from S2GF in the British Columbia's Lower Fraser Valley should be about 0.6% of the total from all sources. **EFSEC concludes that S2GF is unlikely to have a significant impact on vegetation, soils, and aquatic resources in Class I or Class II areas or the analogous areas in British Columbia.**

4.2 OTHER AIR QUALITY IMPACTS

During the construction phase of the project construction workers will be employed, requiring temporary housing and producing motor vehicle emissions during their daily commute to the work site and from the operation of heavy and other internal combustion engine powered equipment at the project site. During construction, there is the possibility of generating wind blown dust from earth moving operations and vehicle and equipment operation of unpaved areas of the project site or access roads. This dust is not subject to PSD or New Source permitting, but can be restricted during the SEPA process.

It is expected that the majority of employees will come from the local area.

5. AIR POLLUTION CONTROL REGULATORY REQUIREMENTS

This project is subject to the following federal regulations:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards	40 CFR 60, Subpart Da
New Source Performance Standards	40 CFR 60, Subpart GG
New Source Performance Standards, Quality Assurance Procedures	40 CFR 60, Appendix F
New Source Performance Standards, Performance Specifications	40 CFR 60, Appendix B

Permitting:

Emissions Monitoring and Permitting	40 CFR 75
Sulfur content of natural gas to be monitored in accordance with 40	CFR 60.334(b)(2)
Sulfur content of distillate oil to be monitored in accordance with	40 CFR 60.49b(r)
NO_x Requirements	40 CFR 76

The source is subject to the following state regulations:

General and Operating Permit Regulations for Air Polluting Sources	463-39 WAC
General Regulations for Air Pollution Sources	173-400 WAC
Operating Permit Regulation	173-401 WAC
Controls For New Sources of Toxic Air Pollutants	173-460 WAC

3

Ammonia injection system

Selective catalytic reduction NO_x control system located within the HRSG.

Oxidation catalyst

Continuous emission monitoring system (CEMS) designed to continuously record the measured gaseous concentrations, and calculate and continuously monitor and record the NO_x and CO concentrations corrected to fifteen (15) percent oxygen (O_2) on a dry basis.

3. Unit 1 Steam turbine generator and condenser serving gas turbine units 1A and 1B, quadruple admission, triple extraction, 258 MW nominal rated electrical output.

B. Combined Cycle Unit 2 Consisting of:

1. Gas Turbine Unit 2A Consisting of:

Gas Turbine Generator, General Electric Frame 7, Model PG7241, rated at 1,850 mmBtu/Hr maximum heat input and 180 MW nominal electrical output, dry low-NO_x combustor.

Duct burner, Rated at 426 mmBtu/hr

Heat recovery steam generator (HRSG), nominal ratings: high pressure steam capacity: 745,000 lb/hr @ 1670 psia and 1050 deg F, intermediate pressure steam capacity: 765,000 lb/hr @ 480 psia and 1035 deg F, low pressure steam capacity: 17,500 lb/hr @ 80 psia and 610 deg F.

Ammonia injection system

Selective catalytic reduction NO_x control system located within the HRSG.

Oxidation catalyst

Continuous emission monitoring system (CEMS) designed to continuously record the measured gaseous concentrations, and calculate and continuously monitor and record the NO_x and CO concentrations corrected to fifteen (15) percent oxygen (O_2) on a dry basis.

2. Gas Turbine Unit 2B Consisting of:

Gas Turbine Generator, General Electric Frame 7, Model PG7241, rated at 1,850 mmBtu/Hr maximum heat input and 180 MW nominal electrical output, dry low-NO_x combustor.

Duct burner, Rated at 426 mmBtu/hr

Heat recovery steam generator (HRSG), nominal ratings: high pressure steam capacity: 745,000 lb/hr @ 1670 psia and 1050 deg F, intermediate pressure steam capacity: 765,000 lb/hr @ 480 psia and 1035 deg F, low pressure steam capacity: 17,500 lb/hr @ 80 psia and 610 deg F.

Ammonia injection system

Selective catalytic reduction NO_x control system located within the HRSG.

Oxidation catalyst

Continuous emission monitoring system (CEMS) designed to continuously record the measured gaseous concentrations, and calculate and continuously monitor and record the NO_x and CO concentrations corrected to fifteen (15) percent oxygen (O_2) on a dry basis.

3. Unit 2 Steam turbine generator and condenser serving gas turbine units 2A and 2B, quadruple admission, triple extraction, 258 MW nominal rated electrical output.

V. PROPOSED OPERATION

Duke Energy Morro Bay LLC proposes to operate the Combined Cycle Units on a "merchant plant" basis. The equipment will be operated when it is economically viable for the power generated to be sold to the power grid.

To establish emission offset levels, Duke proposes overall facility-wide yearly emission limits in addition to the emission limits determined by Best Available Control Technology (BACT). Duke based their proposed limits on certain assumptions regarding operating practices. For each calendar quarter, Duke assumed each of the four Gas Turbines would operate 1,000 hours full load with duct burners, 1,000 hours full load without duct firing and 100 hours of start-up operation. This would equate to calculations based on 8,000 full load hours of turbine operation, 4,000 hours of concurrent duct burner operation and an additional 400 hours of start-up operation per year total. Since the estimates of start-up and full load emissions reflect worst-case emission conditions, it is possible that operating hours could exceed 8,400 hours, without exceeding the emissions levels analyzed in this evaluation. Compliance with the proposed offset emission levels will be determined by using a continuous emissions monitoring system and by limiting startups.

Duke is proposing the following facility cap for all power generation equipment at the facility:

Table 1: Applicant Proposed Facility Cap (tons per year, tpy)

NO_x	SO_x	CO	VOC	PM_{10}
292.3	23.0	917.4	77.6	203.2

VI. AIR QUALITY IMPACT ANALYSIS

In their AFC, Duke provided an Air Quality Impact Analysis. This included both screening and refined modeling using the Industrial Source Complex Short-term model 3 (ISCST3) to address the impacts of the project. The modeled project impacts were combined with background concentrations to verify that the project would not contribute to violations of either the State or federal Ambient Air Quality Standards. The District hired an independent modeling contractor to verify that the modeling presented in the application was done correctly.

The information has been extracted from the AFC and is tabulated in Table 2 below. The table addresses the project impacts combined with background concentrations versus the ambient air quality standards. Although the federal Prevention of Significant Deterioration (PSD) program and its associated increment analysis was included in the AFC, it's review and approval is under the jurisdiction of EPA and is not included here.

During the PDOC review period, it was discovered that the input files for the one hour NO_x case did not use the correct operating scenario. The applicant has since used the correct operating scenario and the combined plume mode of Industrial Source Complex, Ozone Limiting Method (ISC_OLM) to recalculate the one-hour NO_x impact. The modeling parameter correction and refinement of the plume mode resulted in a small decrease in projected maximum NO_x impact from 220 micrograms per cubic meter (ug/m^3) to 214 ug/m^3. The District concurs with the results, which are summarized below.

Table 2: Cumulative Impacts vs. Ambient Air Quality Standards

Pollutant	Avg. Period	Max. Project Impact (ug/m^3)	Backgnd Conc. (ug/m^3)	Total Impact (ug/m^3)	State Standard (ug/m^3)	Federal Standard (ug/m^3)	Below Applicable Standard(s)
Carbon Monoxide (CO)	1-hour	8,615.4	6,988	15,603	23,000	40,000	yes
	8-hour	1,508.3	3,444	4,952	10,000	10,000	yes
Nitrogen Dioxide (NO_2)	1-hour	214.1	122	336	470	--	yes
	annual	2.6	25	28	---------	100	yes
PM_{10}	24-hour	24.2	57	81	50	150	no
	annual(1)	2.7	20.6	23	30	--	yes
	annual(2)	2.7	18.6	19	---------	50	yes
Sulfur Dioxide (SO_2)	1-hour	17.3	106	123	650	--	yes
	24-hour	2.7	13	16	109	365	yes
	annual	0.2	0	0.2	---------	80	yes

(1) Annual Arithmetic Mean.
(2) Annual Geometric Mean.

Although Table 2 identifies an exceedance of the State PM_{10} standard when background concentrations are added, the District has determined that this project will not cause or contribute to the violation of an ambient air quality standard. The basis for this determination is the fact that existing PM_{10} concentrations already exceed the standard, and the fact that the facility is fully offsetting PM_{10} emission increases via the use of banked emissions. Therefore, the project as proposed complies with the Ambient Air Quality Standard provisions of Rule 204.D.

VII. HEALTH RISK ASSESSMENT

Health risk assessments typically evaluate three different types of potential health impacts: carcinogenic, which are from long term exposure; acute non-cancer, which result from short term exposure; and chronic non-cancer, which result from long term exposures. A toxic compound can cause any or all of these potential health impacts.

The original AFC contained a screening health risk assessment for toxic emissions from the project. The screening risk assessment has since been modified twice to incorporate comments from the District's data adequacy review. The first modification occurred in a letter from Sierra Research dated November 1, 2000, and added hexane and propylene to the list of toxic contributors. The result was a small increase in the chronic health hazard index. Hexane and propylene do not have acute or carcinogenic risk factors.

The second change to the HRA was also a result of the data adequacy review and was documented in a letter from Sierra Research dated November 21, 2000. This change resulted from the use of the multi-pathway HRA model called Health Risk Assessment Program Version 2.0e (11/1/00), which was developed by the California Air Resources Board (ARB) and the Office of Environmental Health Hazard Assessment (OEHHA). Because of these changes and inconsistencies in the HRA version cited in the data requests, Sierra Research provided a revised summary complete with new multi-pathway HRA model runs using all the latest figures in their letter dated May 9, 2001.

In recent CEC proceedings regarding the Metcalf Energy Center (MEC) Project, acrolein emission rates used in the MEC AFC were questioned. The use of these factors to represent startup emission rates was the main issue. The same factors are used in MBPP AFC. We have reviewed the available data and determined that the emission factor used in the AFC is sufficient, because other valid emission factors have not been found. It should be noted that the applicant's emission factor for acrolein is not significantly higher than that found in EPA's AP42 Table 3.1-3 (6.43 E-3 pounds per million standard cubic foot of fuel burned [lb/mmscf] compared to 6.53 E-3 lb/mmscf, respectively). To ensure that toxic emissions such as acrolein do not cause significant health risk, a condition for low load (startup) source testing for targeted toxic pollutants, including acrolein, has been added. Prior to the District granting an operating permit for the power plant, a revised risk assessment using that source test data must show that the health risks are not significant.

The new power plant cannot be permitted if the total estimated cancer risk exceeds ten in a million. In addition, any project causing risk of greater than one in one million must install Toxic Best Available Control Technology (TBACT) on equipment that increase toxic emissions and on equipment that is relocated. Similar requirements apply for toxic emissions that have chronic and acute health risks, but chronic and acute significance thresholds are based on a ratio of actual exposures to reference exposure levels called the health hazard index (HHI). A project can not be permitted if its chronic or acute HHI exceeds 1.0 for all compounds combined. In addition, any project with an acute or chronic HHI of 0.1 must also apply TBACT to the contributing equipment. Table 3 below summarizes the risks for the maximum exposed individual. By definition the risks to all other offsite sources are lower.

Table 3: Health Risk and Hazard Levels

	Risk or Health Hazard Index From Project	TBACT Required Level	Significance level
Acute Non-Cancer Health Hazard Index (1)	0.355	0.1	1.0
Chronic Non-Cancer Health Hazard Index (1)	0.041	0.1	1.0
Cancer Risk to the Maximum Exposed Individual (1)	1.51 in one million	1 in one million	10 in one million
Cancer Risk without Diesel Engines to the Maximum Exposed Individual	0.17 in one million	Not applicable	Not applicable
Note: Includes existing standby engines and motor vehicle gasoline fueling			

Table 3 shows that toxic emissions do not exceed absolute thresholds of ten in a million risk for cancer causing compounds or an HHI of one for acute and chronic effects. However, TBACT levels for carcinogenic risk of one in million (1.51 in a million) and the acute HHI of 0.1 (0.355) are shown to be exceeded. The dominating cancer risk and health hazard pollutants are diesel exhaust particulate from the diesel standby engines and acrolein from turbine exhaust. Particulate traps are considered TBACT for the diesel engines and oxidation catalysts are considered TBACT for organic compounds, like acrolein, from gas turbines. The project already includes oxidation catalysts on the turbines, so compliance with TBACT will be assured by adding a condition to the FDOC requiring diesel particulate traps on the standby engines.

VIII. EMISSIONS CALCULATIONS

A. Potential to Emit

The proposed emission parameters are shown in Table 4.

Table 4: Emission Rates

		CONCENTRATION (ppmvd @ 15% O_2)	EMISSION FACTOR (lb/mmBtu)	EMISSION RATE[1] (lb/hr)
Each Gas Turbine Baseload no duct firing	NO_x	2.0[3]	0.00723	13.38
	SO_x	0.139	0.000703[2]	1.30
	VOC	1.15[3]	0.0015	2.71
	CO	2.0[3]	0.0044	8.137
	PM_{10}/TSP		0.0059[4]	11.0[4]
Each Gas Turbine Baseload with duct firing	NO_x	2.0[3]	0.00723	15.46
	SO_x		0.000703[3]	1.50
	VOC	2.0[3]	0.0025	5.39
	CO	2.0[3]	0.0044	9.42
	PM_{10}/TSP		0.0064[4]	13.3[4]
Each Gas Turbine Start-up	NO_x			160.0[4]
	SO_x		0.000703[2]	1.30[2]
	VOC			16.0[4]
	CO			620[4]
	PM_{10}/TSP			9.0[4]

Notes: [1] Maximum emission rates based upon maximum heat input of 1,850.4 mmBtu/Hr for the turbines and 290.8 mmBtu/Hr for the duct burners.
[2] Based upon fuel sulfur content of 0.25 gr/100 dscf natural gas.
[3] BACT levels established by Rule 204.
[4] Peak emission rate, total startup and shutdown limited to 4 hours per day and 320 lbs NO_x.
[5] ppmvd is "parts per million by volume on a dry basis"

The maximum daily potential to emit is shown in Table 5 for oxides of nitrogen (NO_x), carbon monoxide (CO) and volatile organic compounds (VOC) and is based upon an operating scenario where each turbine has a 4-hour cold start-up cycle, 4 hours of base load without duct firing, and 16 hours of full load operation with duct firing. The maximum daily emissions for particulate matter less than ten microns (PM_{10}) and sulfur dioxide (SO_2) do not vary with startup, so their maximum emissions occur with the largest fuel use day. This occurs when there is no startup and each turbine is operated at 8 hours of base load without duct firing and 16 hours of full load operation with duct firing. Note that all of these operational time periods reflect constraints included in the conditions to this determination.

Table 5: Maximum Daily Potential to Emit (Pounds/Day)

EQUIPMENT	NO_x	SO_2	VOC	CO	PM_{10}
Gas Turbine (1 of 4) Start-up and shutdown(1)	320.0	5.2	64.0	2,480.0	44.0
Gas Turbine Baseload (1 of 4) No duct burner (2)	53.5	5.2	10.8	32.5	44.0
Gas Turbine Baseload (1 of 4) With Duct Burners(3)	247.3	23.2	86.2	150.7	212.8
Total one turbine w/ Duct burner	620.8	33.6	161.0	2,663.2	300.8
Total all four turbines	2,483.2	134.4	644.3	10,652.8	1,203.2

Notes: (1) 4 hours of start-up and shutdown for NO_x, VOC and CO(NOx averages 80 lb/hr with 160 lb/hr peak emissions), 4 hours baseload no duct firing burners for SO_x and PM_{10}.
(2) 4 hours of operation at full turbine load no duct burners
(3) 16 hours of operation at full load turbines and duct burners

The NO_x and CO emissions have been reduced compared to the application and the PDOC levels to account for lower NO_x and CO hourly concentrations limits (See BACT below and Response to EPA comments #1 and #2).

B. Best Available Control Technology (BACT)

The applicable BACT thresholds from Rule 204, Section A, the proposed maximum daily emissions for each turbine and the determination as to whether BACT is required are shown below in Table 6. As can be seen in Tables 5 and 6, BACT is required for all of the criteria pollutants.

Table 6: Determination if BACT is Required

Pollutant	BACT Emission Threshold (lbs/day)	Proposed Project Emissions (lbs/day)	BACT Required
NO_x as NO_2	25	620.8	Yes
SO_x as SO_2	25	33.6	Yes
VOC	25	161.0	Yes
CO	250	2,663.3	Yes
PM_{10}	25	300.8	Yes

For the gas turbines, Duke has proposed the following as BACT.

Table 7: Gas Turbine BACT Proposals

Pollutant	Applicant's Proposal	BACT as Defined in ARB Power Plant Siting Document	Additional Discussion Required?
NO_x as NO_2	2.5 ppmvd @ 15% O_2 1-hour rolling average	Same	Yes
SO_x as SO_2	Emission Limit Based on Natural Gas Fuel with <0.25 grains-S/100 dscf	Emission Limit Based on Natural Gas Fuel with <1 grain-S/100 dscf	No
VOC	2.0 ppmvd @ 15% O_2 1-hour rolling average	Same	No
CO	6.0 ppmvd @ 15% O_2 3-hour rolling average	Same	Yes
PM_{10}	Emission Limit Based on Natural Gas Fuel with <0.25 grains-S/100 dscf	Emission Limit Based on Natural Gas Fuel with <1 grain-S/100 dscf	No

The applicant has proposed BACT as recommended by the California Air Resources Board or better for all criteria pollutants. For NO_x, that level is 2.5 ppmvd @ 15% O_2 on a 1-hour rolling average with 5 ppmvd ammonia slip. In data request number 187, the CEC explained that they recently approved a similar turbine project with a NO_x limit of 2.0 ppmvd; they asked how the applicant would achieve the BACT level of 2.0 ppmvd NO_x. The applicant responded that the 2.0 ppmvd NO_x limits included the allowance of 10 ppmvd ammonia slip. During the PDOC comment period, the District evaluated the feasibility, benefits and operational impacts of a BACT limit of 2.0 ppmvd NO_x. Also, during the comment period EPA commented that BACT should be 2.0 ppmvd NO_x with 5 ppmvd ammonia slip and 2.0 ppmvd CO. The District contacted vendors of both SCR and oxidation catalyst and found that they can and have guaranteed those emission levels with the type of control systems proposed. Consequently, the District finds that BACT for NO_x shall be 2.0 ppmvd @ 15% O_2 calculated on a 1-hour rolling average with an ammonia slip limit of 5 ppmvd @ 15% O_2 and that BACT for CO shall be 2.0 ppmvd @ 15% O_2 calculated on a 3-hour rolling average. However, the District acknowledges that additional time may be necessary to tune the equipment to these ultra low one and three hour average emission levels. Therefore, we have phased in the short-term ammonia and CO emission limits. The ammonia emission limit will start at 10 ppmv for the first 12 months of operation, drop to 7.5 ppmv for the second 12 months of operation and then be set at 5 ppmv after two years. CO will start at 4.0 ppmv and drop to 2.0 ppmv after 12 months. The quarterly emission limits will not be affected and ambient ammonia concentrations will remain below significance thresholds.

In response to public comment, peak quarterly emission limits were added to the annual emission limits for NO_x, SO_x, CO, VOC and PM_{10}. The peak quarterly emission limits were based on 92 days (two longest quarters) at 24 hours per day and 8,400 hours of operation per year. The calculation for peak quarterly CO emission limit was revised beyond a straight quarterly adjustment to account for the new lower 2-ppmv CO limit. The calculation was made as follows:

Yearly CO = 4 units*(400 hrs startup*620 lb/hr + 4,000 hrs base load no duct firing *8.137 lb/hr + 4,000 hrs maximum load*9.43 lb/hr) / 2000 lb/ton = 636.54 tons/year.

CO Peak Quarterly = 92 days*24 hours/day / 8,400 hrs/year * 636.54 tons = 167.31 tons/quarter

The NO_x did not require adjustment beyond the quarterly calculation because the PDOC annual NO_x was based on average NO_x level of just under 2.0 ppmvd.

C. Offsets, Rule 204, Section B

Rule 204, Section B requires that offsets be provided for all emissions increases where the potential to emit is above 25 tons per year for NO_x, VOC, PM_{10} and SO_x and 250 tons per year for CO. This project exceeds the thresholds for all five pollutants.

The calculation of the emissions increase is determined by the requirements of Rule 213.D.1. This section specifies the projects emissions increase as the potential to emit for the new turbines, which will be based upon the proposed facility emissions cap.

D. Emissions Banking, Rule 211

The offsets for the proposed project are coming from three sources: Emission Reduction Credits (ERCs) from the elimination of fuel oil use (Certificate #694-Z1), ERCs acquired from Chevron USA (Certificate #s 359-Z2, 690-Z1, 691-Z1, 692-Z1 & 693-Z1), and emission reductions from the shutdown of the existing four boilers at the current power plant. The first two sources are certified ERCs that have recently been through the banking process and do not require further review. However, the emissions from the shutdown of four boilers have not been evaluated for banking criteria. The basic criteria for banking are that the reductions are real, quantifiable, permanent, surplus and enforceable.

REAL: Boiler use has been documented in the emissions inventory, with continuous emissions monitoring data and through inspections. Real reductions will occur when boilers are permanently shutdown.

QUANTIFIABLE: The reductions have been quantified using accepted methods from the EPA publication (AP42 Volume II) and from continuous emissions monitoring data.

PERMANENT: The equipment will be taken out of service and the associated right to operate under permit will be canceled.

ENFORCEABLE: The equipment will be removed and the permit canceled.

SURPLUS: The amount of NO_x reduction has been reduced by Best Available Retrofit Control Technology (BARCT) as required by State Law to ensure the credits are surplus. BARCT has been determined to be the NO_x and CO concentration requirements of Rule 429 and the emissions from natural gas firing for SO_x, PM_{10} and VOC. The emissions of CO, SO_2, PM_{10} and VOC were reduced by 20% as required by District Rule 211.C.1.b, which requires an additional 20% reduction when a source already meets the BARCT requirement. That 20%, which is surplus to any state or federal regulation, is used to fund the District's Community Bank.

Section B, Requirements: Subsection B.1 requires that the ERCs be issued through the banking process, which is satisfied. Subsection B.2 requires that the existing permit be surrendered prior to granting the credits. Any excess credit left over from the project will not be issued until the permit for the existing boiler units 1 through 4 is canceled.

Section C. Emission Reduction Discounts and Limitations: Subsection 1 applies to this shutdown (see SURPLUS discussion above).

E. Banking and Offset Calculations

Appendix A shows the project's bankable emissions and the offset calculation procedure complete with offset profile calculations.

The boiler shutdown emissions calculations provided in the application were generally correct. Some minor differences resulted from the District's use of a gas higher heating value of 1,020 Btu/scf verses the applicant's use of 1,025 Btu/scf. The offset calculations for SO_x and PM_{10} were significantly different. The differences arose because the applicant applied SO_x ERCs to offset PM_{10} increases prior to exhausting PM_{10} ERCs. The District requires that all other direct offsets be exhausted prior to authorizing inter-pollutant trades. For the remaining PM_{10} deficit after utilizing all PM_{10} offsets, each ton of PM_{10} increase will be offset with a ton of SO_2 credits as allowed under the State Air Resources Board's Guidance for Power Plant Siting and Best Available Control Technology (September 1999). Duke has further agreed to retire any leftover SO_2 credits, which results in a defacto ratio of over 2.0 tons of SO_2 credits for every 1.0 ton of PM_{10} increase. The offset profile checks, shown as the Percentage Emissions per Quarter in the attached tables, meet the 80% requirement for all five pollutants.

IX. CONCLUSIONS

This equipment as proposed has the capability of complying with all applicable District rules and federal requirements for which the District has EPA delegation.

A. Compliance Check Against District Regulations

Rule 113 Continuous Emissions Monitoring
This rule requires fossil fuel fired steam generators with heat input rates above 250 mmBtu/hr to install Continuous Emissions Monitoring Systems (CEMs) according to the requirements. CEMs will be installed.

Rule 203 Application
This rule requires that applications be filed in form and content as required by the APCO so that a determination of compliance can be made. Duke Energy Morro Bay LLC filed an Application for Certification (AFC) with the California Energy Commission. Under Rule 223, Power Plants, the AFC is treated like an Authority to Construct application. Duke has met the requirements of Rule 203 through the data adequacy review process.

Rule 204 Requirements
This is the core of the new source review rules (Rules 204, 211, 212, 213, and 214); it contains control technology and offsets provisions. The proposed facility is in compliance with this Rule as shown in Section VII above. Both BACT and offset provisions of this Rule (Sections A and B) were triggered and are included in the above analysis. The Certification of Statewide Compliance (Section E) was also triggered and has been met as documented in a letter from Duke. The permit will be conditioned such that compliance with the emission limits established by this Rule will be continually monitored.

Rule 206 Conditional Approval
This rule authorizes the APCO to place conditions of approval on the proposed facility. This Determination of Compliance contains conditions designed to ensure the facility will operate in compliance with regulatory requirements.

Rule 209 Provision for Sampling and Testing Facilities
The permit will include conditions for air sampling facilities as required by this Rule.

Rule 210 Periodic Inspection, Testing and Renewal of Permits to Operate
The equipment under permit will be inspected periodically, independent emission testing will be required every calendar quarter, and the permit will be subject to review and public comment during the permit renewal process.

Rule 211 Emission Banking
The emission reductions from the boiler shutdowns were evaluated under the provisions of this rule and found to meet the requirements (See Section VII above).

Rule 213 Calculations
This rule specifies the emission increase and emission reduction credit calculations. All calculations were done according to the procedures of this Rule.

Rule 214 Notification
Prior to authorizing a project where emissions will be greater than 100 pounds per day, the APCO must publish a preliminary decision and hold a 30 day comment period. This process will be accomplished through the preliminary and final determination of compliance processes (PDOC & FDOC). A notice of the PDOC will be published in the Tribune of San Luis Obispo County and a comment period will follow. All applicable comments will be addressed in the final DOC.

Rule 216 Federal Part 70 Permits
The permits will be conditioned such that the facility's Title V permit must undergo a "Major Modification" prior to combusting fuel in the Gas Turbines. Upon completing this Title V permit issuance for this "Major Modification," the facility will be in compliance with the requirements of this Rule.

Rule 217 Federal Part 72 Permits
The facility is presently an "Acid Rain" source, and will remain so after this project. A new application for a Acid Rain Permit has been received; when approved it will be incorporated into the facility's Title V Permit. Therefore, when the Title V Permit is updated, the facility will also be in compliance with the requirements of this Rule.

Rule 219 Toxics New Source Review
The project is subject to section E.4 of Rule 219. Compliance with this rule, as discussed Section VI, Health Risk Assessment, is shown with a cancer risk of less than ten in million and TBACT (diesel particulate trap requirement) and an HHI of less than one (1.0) and TBACT (turbine oxidation catalyst).

Rule 223 Power Plants
This rule specifies the procedures used by the District to evaluate projects that are filed through an Application for Certification with the California Energy Commission. This rule requires the project to comply with the same requirements as an Authority to Construct. This DOC evaluation has used the same standards as required for an Authority to Construct.

Rule 302 Schedule of Fees
Fees for issuance of an Authority to Construct, which is equivalent to this DOC, are based on the actual cost incurred by the District. Duke will be billed for all applicable District permit costs.

Rule 401 Visible Emissions
The equipment is natural gas fired, and therefore should easily comply with the 40% opacity standard from this Rule. Appropriate conditions will be include on the permits to ensure compliance with the requirements of this Rule.

Rule 402 Nuisance
With the equipment being fired on natural gas, nuisance type problems are not expected from this operation. However, appropriate conditions will be included on the permits to ensure compliance with the requirements of this Rule.

Rule 403 Particulate Matter Emission Standards
The 0.3 grains per dry standard cubic foot @12%CO2 emission limit is applicable to the Gas Turbines at the facility, but this standard is superseded by the emission limitations imposed through the new source review permitting process. Based on the requirements of Rule 403, the volumetric flow rate of 18.65 mm SCFH for the Gas Turbine would establish an emission limit of 799 lbs PM_{10}/hr as follows: (18.65 mmscfh) (0.3 grains/SDCF) (1 lb/7000 grains) = 799 lbs PM_{10}/hr. Based on the emission limits required through this permitting process, the PM_{10} emission limit for each gas turbine with Duct burner is 13.3 lbs/hr, which is well below the applicable Rule 403 standards. Section C also contains a 10 lb/hr particulate matter limit for each individual combustion device. The total maximum emissions from a turbine and duct burner system is 13.3 lb/hr. Of that total, each turbine will not exceed 9.0 lb/hr and each duct burner will not exceed 4.3 lb/hr. Both are below the 10 lb/hr prohibition in the rule.

Rule 404 Sulfur Compounds Emission Standards, Limitations and Prohibitions
This rule, which limits the sulfur content of any gaseous fuel combusted to 50 grains or less of sulfur per 100 cubic feet, is applicable to this equipment. The sulfur content limits proposed in the application are 0.25 grains per 100 cubic feet of natural gas. This sulfur limit will be included on the permit.

Rule 405 Nitrogen Oxides Emission Standards, and Prohibitions
This rule contains a 140 lb/hr NO_x limit for each individual combustion device. The maximum emission from any single combustion device is 80 lb/hr of NO_x from a turbine in startup mode. This is well below the 140 lb/hr prohibition.

Rule 406 Carbon Monoxide Emission Standards and Limitations
This rule contains a 2,000 ppmvd CO emission limit for any discharge point. The turbine unit is equipped with a CO catalyst and has an emission limit of 6 ppmvd which is well below the 2,000 ppmvd prohibition.

Rule 429 Oxides of Nitrogen and Carbon Monoxide Emissions from Electric Power Generation Boilers
This rule establishes numerous requirements on the existing boilers at the Morro Bay Power Plant. These boilers are being removed from service so the requirements of this rule will not apply to the new power plant.

B. Compliance Check Against Delegated Federal Requirements

Rule 601 New Source Performance Standards (NSPS)
40 CFR Part 60, Subpart A -General Provisions

The facility is subject to the requirements of this part because the equipment is subject to 40 CFR Subpart GG and Subpart Da which in turn requires compliance with Subpart A.

The notification and record keeping, performance tests, compliance with standards and maintenance requirements, circumvention, monitoring requirements, and general notification and reporting requirement provisions contained in §§60.7, 60.8, 60.11, 60.12, 60.13, and 60.19 will be satisfied under the testing, monitoring and reporting requirements established as conditions on the permit pursuant to District requirements. This will include initial testing, annual testing, record keeping, reporting, and the requirement to monitor operations with the use of CEMs

40 CFR Part 60, Subpart GG -Standards Of Performance For Stationary Gas Turbines

The Gas Turbines are subject to the requirements of this NSPS. In addition to utilizing good combustion practices and combusting only natural gas, the Gas Turbines utilize dry-low NO_x combustion, and the back-end control of selective catalytic reduction (SCR) to limit pollutant emissions.

The allowable NO_x concentration limit derived from §60.332(a)(1) would be 169 ppmvd, when using the heat rate 6.375 kJ/W-hr. This 169 ppmvd limit far exceeds the 2.0 ppmvd limit established by the BACT requirements. Therefore, the NO_x limit from the NSPS will be satisfied by the NSR permit requirements that will be included on the permits.

Note that the application assumed the wrong emissions standard §60.332(a)(2); however, it had no bearing on the outcome because of the more stringent BACT emission limit.

The allowable SO_2 concentration limit derived from §60.333 would be 150 ppmvd. Compliance with this limit is assured due to limits established by the BACT requirements of 0.25 grains per 100 scf of gas. The SO_2 concentration at this permitted emission level would be less than 1 ppmvd. This value is well below the 150 ppmvd SO_2 allowed in the NSPS. Therefore, the SO_2 emission standard from this NSPS will be satisfied by the NSR permit requirement that will be included on the permits.

The testing and monitoring requirements contained in §§60.334 and 60.335 will be satisfied by the testing and monitoring requirements established under the NSR conditions contained on the permits. This will include the annual emissions testing requirement and the requirement to monitor operations with the use of CEMs.

40 CFR Part 60, Subpart Da -Standards Of Performance For Electric Utility Steam Generating Units for which Construction is Commenced After September 18, 1978

The duct burners combined with the heat recovery steam generators are boilers and are subject to the requirements of this NSPS because the heat rating exceeds 250 mmBtu/hr. In addition to utilizing good combustion practices and combusting only natural gas, the duct burners are low NO_x units with emissions further controlled by SCR systems and oxidation catalysts.

The allowable PM_{10} concentration limit contained in §60.42a is 0.03 lb/mmBtu. This 0.03 lb/mmBtu limit is less stringent than the 0.0064 lb/mmBtu limit established by the 13.26 lb/hr emission limit. It should be noted that this limit includes turbine exhaust, which may have slightly different emissions per mmBtu of fuel. However, the applicant's scenarios assume that operation with duct burners will result in slightly lower lb/mmBtu levels than without them. This means that the duct burners are expected to emit below 0.0064 lb/mmBtu. AP42 emission factors also support the conclusion that emissions will be far below the 0.03 lb/mmBtu NSPS limit. Therefore, the PM_{10} limit from the NSPS will be satisfied by the NSR requirements that will be included on the permit.

The allowable SO_2 concentration limit derived from §60.43a is much greater than the emission level allowed by BACT. Compliance with this limit is assured due to limits established by the BACT requirements of 0.25 grains per 100 scf of gas. The SO_2 emissions at this level are 0.0007 lb/mmBtu which is far less than any standard in this regulation. Therefore, the SO_2 emission standard from this NSPS will be satisfied by the NSR permit requirement that will be included on the permits.

The allowable NO_x concentration limit contained in §60.44a is 0.20 lb/mmBtu. This 0.20 lb/mmBtu limit is less stringent than the 0.00723 lb/mmBtu limit established by BACT requirements (2.0 ppmvd). Therefore, the NO_x limit from the NSPS will be satisfied by the NSR permit requirements that will be included on the permits

The testing and monitoring requirements established under the NSR conditions will satisfy the testing and monitoring requirements contained in §§60.47a. This will include the annual emissions testing requirement and the requirement to monitor operations with the use of CEMs.

Rule 701 National Emission Standards for Hazardous Air Pollutants (NESHAPS)

40 CFR Part 61, Subpart A - General Provisions

The facility is subject to the requirements of this part because the facility is subject to 40 CFR Part 61, Subpart M. Historically, the facility has been in compliance with these requirements and continued compliance is expected.

40 CFR Part 61, Subpart M - National Emission Standard For Asbestos

The facility, on occasion, is subject to the requirements of 61.145 - 61.147 (Standards for Demolition and Renovation). Historically, the facility has been in compliance with these requirements and continued compliance is expected.

X. RECOMMENDATION

The APCO finds the application to be in compliance with the regulations delegated to the District, if built and operated according to following conditions:

Definitions:

CEC CPM: California Energy Commission Compliance Program Manager
Clock Hour: Any continuous 60-minute period beginning on the hour.

Calendar Day: Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.

Commissioning Period: The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing and is available for commercial operation.

District: San Luis Obispo County Air Pollution Control District

Firing Hours: Period of time during which fuel is flowing to a unit, measured in fifteen minute increments.

Heat Input: All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf.

mmBtu: million British thermal units

Quarterly Emissions: Emissions which occur in the calendar quarters: January through March, April through June, July through September and October through December.

Rolling 3-hour period: Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Year: Any consecutive twelve-month period of time

Conditions Prior to Combusting Fuel

1) The owner/operator shall submit to the District all design criteria and specifications that affect air pollutant emissions or emission measurements systems, for the Selective Catalytic Reduction (SCR) system, the ammonia injection system, the oxidation catalyst and the continuous emission monitoring (CEM) systems, and shall receive Air Pollution Control Officer (APCO) approval prior to installation.

2) Pursuant to the requirements of District Rule 216, the owner/operator shall apply for and receive a revised Title V permit for the Morro Bay Power Plant prior to the first firing of the Gas Turbine Units.

3) District-approved continuous emission monitors (CEMs) shall be installed, calibrated, and operational prior to the first firing of the Gas Turbines Units. After commissioning of the Gas Turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the normal range of Carbon Monoxide (CO), ammonia (NH3) and oxides of Nitrogen (NO_x) emission concentrations, which shall include startup conditions. The type, specifications, and location of these monitors shall be subject to District review and approval. The CEM Operation and Works Plans shall be submitted for District comment and approval no later than 60 days prior to first firing of the Gas Turbine Units. The owner/operator shall also install and maintain a telemetric data acquisition system at the District office. The owner/operator may use a predictive emission monitoring system (PEMs) during the first three (3) years of operation in lieu of the ammonia CEMs. If the PEMs is chosen for ammonia, the

owner/operator shall submit a plan for APCO approval six (6) months prior to the first firing of the Gas Turbines Units. The plan must be approved by the APCO prior to installation. Operation and equipment installation for the PEMs, shall occur according to the provisions of the APCO approved PEMs plan.

4) The owner/operator shall submit a Start up and Commissioning Plan to the APCO and CEC CPM for approval at least 90 days prior to the first firing of the Gas Turbines. This plan shall describe the procedures to be followed during the commissioning of the Gas Turbines, duct burners, the heat recovery steam generator (HRSG), and the steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the dry-low-NO_x combustors, the installation and operation of the SCR systems, the installation and operation of the oxidation catalyst system and the installation, calibration, and testing of the CO, NH3 and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines without abatement by the SCR and oxidation catalyst systems.

5) No later than seven (7) days prior to the first firing of the Gas Turbine Units, the owner/operator shall notify the District and arrange for an inspection of the equipment.

6) The owner/operator shall surrender the offsets identified in this evaluation or other offsets approved by the APCO equal to the amount of permitted emissions prior to the first firing of the Gas Turbine Units.

7) Twenty-four (24) months prior to the first firing of the Gas Turbine units or 90 days following CEC approval of 00-AFC-12, whichever is later, the owner/operator shall submit a plan for performing ambient air monitoring, and shall obtain APCO approval for that monitoring. The plan shall provide for air monitoring at two separate locations in the surrounding area, to be performed by an APCO-approved third party. Continuous parameters measured at each location shall include NO, NO2, NO_x, NH3, CO, and surface wind speed and direction; 24-hour particulate matter samples 10 microns or less in size (PM 10) shall be taken on the standard 1 day in 6 schedule at each site. The monitoring locations will be selected, subject to APCO approval, with the intent to be best indicators of potential project air quality impacts and/or to be locations of highest community concern. The monitoring shall meet all requirements contained in the District's GUIDELINES FOR AMBIENT AIR QUALITY AND METEOROLOGICAL MONITORING, dated March 1993, including a forthcoming update to electronic data submission requirements or meet requirements determined by the APCO to be equivalent. Pre-combustion monitoring shall occur at each of these sites for twelve months prior to turbine startup, with the length of monitoring period and the starting date of monitoring subject to APCO approval.

At each of these sites, ambient air monitoring for the same parameters noted above shall then be conducted continually until one year following the start of commercial operation.

The duration of this monitoring may be extended for one or both of the sites per APCO approval, for up to three additional years. This extension may occur at each site if requested by the APCO and justified by the monitoring data according to a protocol to be developed and agreed upon by both the APCO and Duke. With APCO approval, the monitoring parameters included in this extended monitoring may be reduced to those which are determined to have key importance in evaluating the impact of plant emissions on the surrounding community.

8) If the turbine foundations are not completed within 30 months of the Final Determination of Compliance (FDOC) issuance, the project shall go through a new Best Available Control Technology (BACT) determination subject to APCO approval before the foundations are poured. This determination shall be made through a supplemental Authority to Construct application. The project shall comply with the new APCO approved BACT determination and any conditions required of that determination.

9) The owner/operator shall obtain APCO approval of any offsite gas metering system that will provide fuel to new turbine units. The metering system shall not release natural gas under normal operations.

10) The owner/operator shall take action to ensure that rust like particulate (RLP) is not emitted from any of the HRSGs. Such action shall include:

a) Developing and submitting a RLP control and monitoring plan to the APCO at least 180 days prior to the first firing of any Gas Turbine Unit.

b) Obtain APCO approval for the RLP plan at least 120 days prior to the first firing of any Gas Turbine Unit

c) Performing maintenance, monitoring and recordkeeping according to the APCO approved RLP plan.

Turbine Commissioning Conditions

11) The owner/operator shall minimize emissions of NO_x and CO from the Gas Turbine Units to the maximum extent possible during the commissioning period according to the APCO approved Start up and Commissioning Plan.

12) At the earliest feasible opportunity in accordance with the recommendation of the equipment manufacturer, the combustors of the Gas Turbines and duct burners of HRSGs shall be tuned to minimize NO_x and CO emissions.

13) At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturer's, the SCR and oxidation catalyst systems shall be installed, adjusted, and operated to minimize the emissions of nitrogen oxides, ammonia and carbon monoxide from the gas turbines.

14) The total number of firing hours of each Gas Turbine and its duct burner without abatement of nitrogen oxide emissions by the SCR System shall not exceed 300 hours during the commissioning period. Such operation of the Gas Turbine without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR and oxidation catalyst systems in place. Upon completion of these activities, the owner/operator shall provide written notice to the District and the unused balance of the 300 firing hours without abatement will expire.

15) The total mass emissions of nitrogen oxides, carbon monoxide, volatile organic compounds, PM_{10}, and sulfur dioxide that are emitted from each Gas Turbine during the commissioning period shall accrue towards the quarterly emission limits specified in Condition 24.

16) During the commissioning period, the owner/operator shall demonstrate compliance with conditions 13 and 14 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

firing hours
fuel flow rates
stack gas nitrogen oxide emission concentrations,
stack gas carbon monoxide emission concentrations
stack gas oxygen concentrations.

The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbine Units. The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

17) Not more than thirty days after the end of the Commissioning Period, the owner/operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 27. The source test shall determine NO_x, CO, and VOC emissions during start-up and shutdown of the gas turbines. The VOC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Twenty working days before the execution of the source tests, the owner/operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the owner/operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The owner/operator shall incorporate the District and CEC CPM comments into the test plan. The owner/operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

The following source test methods shall be used unless otherwise directed by the APCO: EPA Methods 201A/202 (PM_{10} and condensible particulate matter) for PM_{10}; EPA Method 7E or 20 for NO_x ; EPA Method 10 or 10B for CO; EPA Method 3, 3A, or 20 for O_2; EPA Method 18 for VOC.

18) Not more than thirty days after the end of the Commissioning Period and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on each HRSG exhaust stack while the gas turbines and associated HRSG duct burner are operating at maximum allowable operating rate and at minimum load (simulating startup conditions) to demonstrate compliance with Condition 19 for formaldehyde, acrolein, benzene and polycyclic aromatic hydrocarbons (PAHs). If three consecutive biennial source tests demonstrate that the annual emission rates are 75% below the established significance levels contained in District Rule 219, then the owner/operator may discontinue future testing for that pollutant under this permit condition.

19) For the entire facility, the cancer risk shall not exceed ten in a million and the health hazard index shall not exceed one as determined by the procedures contained in District Rule 219, Toxic New Source Review.

20) To demonstrate compliance with Condition 19, the owner/operator shall calculate and record on an annual basis the maximum projected emissions of: acrolein, formaldehyde, PAHs and benzene. Maximum projected annual emissions shall be calculated using the maximum heat input rate and the highest emission factor (pounds of pollutant per mmBtu of heat input) determined by any source test of the Gas Turbine Units.

21) The owner/operator shall perform a revised health risk assessment to update emissions of acrolein, benzene, PAHs and formaldehyde using the emission rates determined by the source test required under condition 18 and the most current District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date.

22) Not more than thirty days after the end of the Commissioning Period and once every 6 months thereafter, the owner/operator shall conduct a District-approved PM_{10} source test on each HRSG exhaust stack to demonstrate compliance with Condition 25. The testing must be performed at three load levels: full gas turbine load with duct firing, full load without duct firing, and partial load without duct firing. If any two consecutive source tests demonstrate that emission rates at a specified load level is less than 75% of the permitted limits, source testing for that load level shall only be required once in every 12 month period.

Gas Turbine Unit Operating Conditions:

23) The heat input rates shall not exceed the following:

Each gas turbine:	1,850.4 mmBtu/hr
Each duct burner:	426.2 mmBtu/hr
Each Gas Turbine Unit	2,141.2 mmBtu/hr, 49,062.4 mmBtu/day
Total all Gas Turbine Units	66,826,240.0 mmBtu/year

24) The maximum daily combined emissions from the gas turbine units, including start-ups and shutdowns, shall not exceed the following limits:

Pollutant	Lbs/Day
Oxides of Nitrogen (NO_x)	2,483.2
Carbon Monoxide (CO)	10,652.8
Particulate Matter <10 microns (PM_{10})	1,203.2
Volatile Organic Compounds (VOC)	644.3
Ammonia (NH_3)	1,336.5
Sulfur Dioxide (SO_2)	134.4

25) The pollutant mass emission rates in the exhaust discharged to the atmosphere from each Gas Turbine unit shall not exceed the following limits:

Pollutant	Lbs/Hour	Lbs/Day
Oxides of Nitrogen (NO_x)	15.5	354.3
Carbon Monoxide (CO)	9.4	215.8
Particulate Matter <10 microns (PM_{10})	13.3	300.8

Volatile Organic Compounds (VOC)	5.4	107.9
Ammonia (NH_3)	14.6	334.1
Sulfur Dioxide (SO_2)	1.5	33.6

These limits shall not apply during start-up, which is not to exceed four (4) hours. SCR and oxidation catalyst controls and good engineering practices shall be used to the fullest extent practical during start-up to minimize pollutant emissions. The CO emission limit shall be 18.9 lbs/hour for the first 12 months of operation and 9.4 lbs/hour thereafter. The NH3 limit shall be 29.2 lbs/hour for the first 12 months of operation (1st year), 21.9 lbs/hour for the second 12 months of operation (2nd year) and 14.6 lbs/hour thereafter.

26) The pollutant concentrations discharged to the atmosphere from each Gas Turbine unit shall not ultimately exceed the following limits, calculated at 15 percent O_2, dry, averaged over the time period noted:

Pollutant	Concentration (ppmvd)	Averaging Time
Oxides of Nitrogen (as NO_2)	2.0	rolling one-hour
Carbon Monoxide (CO)	2.0	rolling three-hour
Ammonia (NH_3)	5.0	rolling three-hour

These limits shall not apply during start-up, which is not to exceed four (4) hours, or shutdown, which is not to exceed one (1) hour. SCR catalytic controls and oxidation catalyst and good engineering practices shall be used to the fullest extent practical during start-up to minimize pollutant emissions. Start-up shall be defined as the period of time after fuel flow is initiated until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of condition 26, not to exceed four (4) hours. Shutdown shall be defined as the period of time from noncompliance with the emission concentration limits of condition 21 until termination of fuel flow to the Gas Turbine, not to exceed one (1) hour. The CO emission limit shall be 4.0 ppmv for the first 12 months of operation and 2.0 ppmv thereafter. The NH3 limit shall be 10 ppmv for the first 12 months of operation (1st year), 7.5 ppmv for the second 12 months of operation (2nd year) and 5.0 ppmv thereafter.

27) Start-up pollutant emission rates discharged to atmosphere from each Gas Turbine during a start-up shall not exceed the following limits. These limits apply to any start-up period which shall not exceed four (4) hours.

Pollutant	Lb/startup
Oxides of Nitrogen (as NO_2)	320.0
Carbon Monoxide (CO)	2,480.0
Volatile Organic Compounds (as CH_4)	64.0

28) Each Gas Turbine unit shall be limited to 400 hours of startup and shutdown time per year; no more than two turbines shall be in startup mode at any one time. Each gas turbine shall be limited to a combined start-up and shutdown time of 4 hours per rolling 24 hour period. A log of all startups and shutdowns shall be maintained onsite and retained for the most recent 5-year period. The log shall include date and time of occurrence, total time in startup or shutdown mode, total emissions of NO_x and CO in tons for each event.

29). Emission from all sources shall not exceed the following limits:

Pollutant	tons/quarter	tons/year
Oxides of Nitrogen (NO_x)	76.83	292.30
Carbon Monoxide (CO)	167.32	636.54
Particulate Matter <10 microns (PM_{10})	53.41	203.20
Volatile Organic Compounds (VOC)	20.40	77.60
Sulfur Dioxide (SO_2)	6.05	23.00

30) CEM Systems, including remote District access, shall be installed and operated on each of the Gas Turbine Units. These systems shall be designed to continuously record the measured gaseous concentrations, and shall calculate and continuously monitor and record the CO, O_2, NH_3 and NO_x concentrations, corrected to fifteen (15) percent oxygen (O_2) on a dry basis.

The equipment installed for the continuous monitoring of CO shall be maintained and operated in accordance with 40 CFR Part 60, Appendix F. The equipment installed for the continuous monitoring of O_2 and NO_x shall be maintained and operated in accordance with 40 CFR Parts 72 and 75.

For periods of missing CO data, CO hourly values shall be substituted from valid hourly average data from the previous thirty (30) unit operating days, excluding periods of startup and shutdown. The CO data shall be substituted based on equivalent incremental load ranges.

31) Within sixty (60) days after the commissioning of the Gas Turbines, a Relative Accuracy Test Audit (RATA) must be performed on the CEMS in accordance with 40 CFR Part 60, Appendix B, Performance Specifications; a performance test shall also be performed, and the written test results of the performance tests shall be provided to the District within sixty (60) days after testing. A complete test protocol shall be submitted to the District no later than thirty (30) days prior to testing, and notification to the District at least ten (10) days prior to the actual date of testing shall be provided so that a District observer may be present. Changes to the test date made subsequent to the initial ten day notification may be communicated by telephone or other acceptable means no less than forty-eight (48) hours prior to the new test date.

The performance tests shall include those parameters specified in the approved test protocol, and shall at a minimum include the following:

a. Oxides of Nitrogen (as NO_2): ppmv dry at 15% O_2 and lb/hr.
b. Carbon Monoxide: ppmv dry at 15% O_2 and lb/hr.
c. Ammonia (NH_3): ppmv dry at 15% O_2 and lb/hr

and the following process parameters:

d. Natural gas consumption.
e. Turbine load in megawatts.
f. Stack gas flow rate (SDCFM) calculated according to procedures in EPA method 19, and % CO_2.

General Conditions

32) Each Gas Turbine and related HRSG shall be abated by a properly operated and properly maintained SCR system whenever fuel is combusted at those sources and

the catalyst bed has reached minimum operating Each turbine unit shall be abated by a properly operated and maintained Oxidative Catalyst system.

33) The owner/operator shall take monthly samples of the natural gas combusted. The samples shall be analyzed for sulfur content using District-approved laboratory methods. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to determine the quarterly SO_2 emissions. The quarterly SO_2 emissions shall be determined by using the average sulfur content during the last three (3) measurements along with the amount of fuel combusted during the last three months. Quarterly SO_2 emissions shall be calculated and recorded within 30 days of the end of any month.

34) The APCO shall be notified in writing before any changes are made to operating procedures, equipment, or materials used which have the potential to increase the emission of any air contaminant.

35) This equipment shall be operated and maintained in accordance with the manufacturer's recommendations and the information presented in the application under which this permit was granted.

36) If the APCO determines that the operation of this equipment is causing a public nuisance, the owner/operator shall take immediate action and eliminate the nuisance.

37) The owner/operator shall demonstrate compliance by using properly operated and maintained continuous emission monitors (CEMs) during all hours of operation including equipment Start-up and Shutdown periods, except for periods of CEM maintenance performed in accordance with District requirements, for all of the following parameters:

a. Firing hours and fuel flow rates for the gas turbines and duct burners.

b. Oxygen (O_2) concentrations, Nitrogen Oxide (NO_x) concentrations, and Carbon Monoxide (CO) concentrations.

c. Ammonia injection and emission rates.

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District approved calculation methods to calculate the following parameters:

d. Heat input rate.

e. Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected NH_3 concentrations, NH_3 mass emissions corrected CO concentrations, and CO mass emissions.

Records shall be maintained onsite for a period of five years after creation, unless otherwise allowed by the APCO.

38) For each emission source, the owner/operator shall record the parameters specified in d. and e. of this Condition every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

a. Total heat input rate for every clock hour.
b. The NO_x mass emissions (as NO_2), and corrected average NO_x emission concentration for every clock hour.
c. The CO mass emissions, and corrected average CO emission concentration for every rolling three-hour period.
d. On an hourly basis, the cumulative total NO_x mass emission (as NO_2) and the cumulative total CO mass emissions.
e. For each calendar day, the cumulative total NO_x mass emission (as NO_2) and the cumulative total CO mass emissions.
f. For each calendar quarter, the cumulative total NO_x mass emission (as NO_2) and the cumulative total CO mass emissions.
g. For each calendar year, the cumulative total NO_x mass emission (as NO_2) and the cumulative total CO mass emissions.
h. Records shall be maintained onsite for a period of five years after creation, unless otherwise allowed by the APCO.

39) The owner/operator shall calculate and record on a daily basis, the Volatile Organic Compound (VOC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions, Sulfur Dioxide (SO_2) mass emissions, and Ammonia (NH_3) mass emissions from each source. The owner/operator shall use the actual heat input rates, actual start-up times, actual Shutdown times, and District-approved emission factors to calculate these emissions. Records shall be maintained onsite for a period of five years after creation, unless otherwise allowed by the APCO. The calculated emissions shall be presented as follows:

a. For each calendar day, VOC, PM_{10}, SO_2, and NH_3 mass emissions shall be summarized for each source.

b. On a daily basis, the cumulative total VOC, PM_{10}, SO_2 and NH_3 mass emissions shall be summarized for each calendar quarter and for the calendar year.

40) Instrumentation must be operated to measure the SCR catalyst inlet temperature and pressure differential across the SCR catalyst.

41) The owner/operator shall submit to the Air Pollution Control District a written report each month which shall include:

a. time intervals, date, and magnitude of excess emissions;
b. nature and cause of the excess emission, and corrective actions taken;
c. time and date of each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; and
d. a negative statement when no excess emissions occurred.
e. Records shall be maintained onsite for a period of five years after creation, unless otherwise allowed by the APCO.

42) The owner/operator shall monitor and report SO_2 emissions in accordance with 40 CFR Parts 72 and 75.

43) The owner/operator shall hold "Acid Rain" Sulfur Dioxide Allowances in the compliance subaccounts not less than the total annual emissions of sulfur dioxide for the previous calendar year.

44) The equipment installed for the continuous monitoring of CO_2 or O_2 and NO_x shall be maintained and operated in accordance with 40 CFR Parts 72 and 75.

45) A written Quality Assurance program must be established in accordance with 40 CFR Part 75, Appendix B and 40 CFR Part 60, Appendix F which includes, but is not limited to: procedures for daily calibration testing, quarterly linearity and leak testing; record keeping and reporting implementation, and relative accuracy testing.

46) Pursuant to Clean Air Act Amendments (CAAA) Title IV, Part 75, Section 75.50, permanent records shall be maintained onsite for a period of five years after creation. The records at a minimum shall include all items specified in Section 75.50.

47) Pursuant to CAAA, Title IV, Part 75, Section 75.64, quarterly reports shall be submitted to the District within 30 days following the end of the calendar quarter. The reports must be in electronic format and at a minimum must include all items listed in Section 75.64.

48) The owner/operator shall perform testing monthly (or less frequently if deemed appropriate by the Air Pollution Control Officer) to verify compliance with the Ammonia (NH_3) slip limit. The owner/operator shall conduct this testing in accordance with the collection method specified in BAAQMD Source Test Procedure ST-1B and the analysis specified in EPA method 350.3.

49) Annual performance tests shall be conducted once in every twelve-month period in accordance with Air Pollution Control District test procedures; the written results of the performance tests shall be provided to the District within thirty (30) days after testing. A testing protocol shall be submitted to the District no later than thirty (30) days prior to the testing, and notification to the District at least ten (10) days prior to the actual date of testing shall be provided so that a District observer may be present. Changes to the test date made subsequent to the initial ten day notification may be communicated by telephone or other acceptable means no less than forty-eight (48) hours prior to the new test date.

If the testing cannot be completed during a twelve month period due to the equipment being non-operational or in limited operation at the end of the current twelve month period, the APCO may delay testing until the unit is operating at sufficient capacity.

50) The owner/operator shall report all breakdowns which result in the inability to comply with any emission standard or requirement contained on this permit to the APCO as soon as reasonably possible, but in any case within 4 hours of its detection. The APCO may elect to take no enforcement action if the owner/operator demonstrates to the APCO's satisfaction that a breakdown condition exists.

As soon as the occurrence has been corrected, but no later than 10 days after the breakdown, a written report shall be supplied to the APCO. This report shall include at a minimum:

a. a statement that the condition or failure has been corrected and the date of correction; and
b. a description of the reasons for the occurrence; and
c. a description of the corrective measures undertaken and/or to be undertaken to avoid such an occurrence in the future; and
d. pictures of the failed equipment when applicable.

51) The owner/operator shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to District review and approval.

52) No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three (3) minutes in any one (1) hour which is as dark or darker than Ringlemann 1 or equivalent 20% opacity.

53) If any of the existing standby diesel engines are relocated to the new turbine plant, the owner/operator shall provide written notice to the APCO, and shall receive written approval from the APCO, prior to such relocation. Any notice of proposed relocation shall be accompanied by a health risk assessment prepared in accordance with District Rule 219. If the APCO determines the health risk exceeds the toxic impact limits of Rule 219, the owner/operator shall install APCO approved oxidation particulate traps or APCO approved equivalent controls on any relocated standby diesel engine rated at 50 hp or greater prior and use ultra low sulfur fuel.

54) Any representative of the Air Pollution Control District authorized by the Air Pollution Control Officer shall be permitted, pursuant to the authority contained in Section 41510 of the California Health and Safety Code:

a. to enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this authorization;
b. to have access to and copy any records required to be kept under the terms and conditions of this authorization;
c. to inspect any equipment, operation, or process described or required in this authorization; and,
d. to sample emissions from the source.

55) The turbines and duct burners shall be fired exclusively on natural gas.

56) The minimum stack height of any HRSG shall each be at least 145 feet above grade level at the stack base.

4

Energy Facilities

ANP Blackstone Energy Project

DEP Permitting Status
01/11/2000

Permit/Approval	Dates / file #	Comment
7.02 Air Quality major comprehensive approval to construct, Prevention of Significant Deterioration (PSD) [see Appendix A of air regs].	Combined Filing 12/24/97 Hearing held 04/1/99 Conditional Approval issued 04/16/99 Construction begun 07/30/99	NOx 2.0ppm, ammonia slip @ 2ppm...noise easements, CO 3ppm, gas only, Section 61 findings included in approval. Noise easements
Industrial waste water	Not filed yet	To Blackstone sewer system
Sanitary Waste Water	Not filed yet	On site disposal proposed, title 5 system needed
Water Supply	Not filed yet	Cross connection water to come from Blackstone municipal system
Wetlands / 401 water quality certificate	Determination of need issued 1/13/98	Notice of intent required

State Permits [other]

Agency Name	Permit/Approval	Dates / File #	Comment
Energy Facilities Siting Board	EFSB Approval	Certificate Issued 01/14/99	
EOEA	MEPA	ENF 6/30/97 draft EIR 12/1/97, final EIR 5/29/98 approved 7/10/98	
MA Natural Heritage Program	Endangered species review	Letter issued 4/30/97	
MA Historical Commission	Historical Archaeological Review		
MA Dept. of Public safety	Fuel Oil Storage Tank Approval [over 10k gallons]		Fuel oil use request withdrawn by proponent
MA State Fire Marshall	Hazardous Substances Tank Approval	To be filed by construction contractor	

Federal Permits

Agency Name	Permit/Approval	Date Filed/ File #	Comment
Federal Aviation Administration	Notice of Construction of Stack	To be filed	
Army Corps of Engineers	Programmatic General Permit Review		Applicability to be determined.
U.S Fish and Wildlife	Endangered Species Review	Letter issued 4/30/97	
U.S. Environmental Protection Agency [EPA]	NPDES construction storm water discharge permit		Notice of intent to be filed by construction contractor
EPA	NPDES General storm water discharge permit		Notice of intent to be filed by project operator

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[Contact: William.DiLibero@state.ma.us]

[Blackstone Site Home] [Energy Facilities Home] [MA DEP Home]

Updated: September 23, 1999

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
ONE WINTER STREET, BOSTON, MA 02108 617-292-5500

ARGEO PAUL CELLUCCI
Governor

JANE SWIFT
Lieutenant Governor

BOB DURAND
Secretary

EDWARD P. KUNCE
Acting Commissioner

CONDITIONAL PLAN APPROVAL
PSD APPROVAL & SECTION 61 FINDINGS

ANP Blackstone Energy Company
Elm Street
Blackstone, MA 01504

Re: CR - Blackstone
Electric Generating Facility
Tr. # 118969

Attn: Robert Charlebois

Dear Mr. Charlebois:

The Department of Environmental Protection Bureau of Waste Prevention, Permitting Section, has reviewed the Major Comprehensive Plan Application for the proposed nominal 580 MW combined cycle electric generating facility to be located on Elm Street, Blackstone, Massachusetts as submitted under the seal and signature of George S. Lipka, P.E. Number 29704.

The Department is of the opinion that the material submitted is in conformance with the current Massachusetts Air Pollution Control Regulations and hereby **CONDITIONALLY APPROVES** this facility at the proposed site location and subject to the conditions and provisions stated herein.

This is a "CONDITIONAL" APPROVAL because specific information on the emission control systems (specific manufacturer, model number, and operational parameters), construction plans, certain plant operational and maintenance procedures and the specific information on the continuous emission monitors have not been finalized at this time.

This Approval combines and includes: 310 CMR 7.02(2) Comprehensive Plan Approval; 310 CMR 7.00: APPENDIX A: Emission Offsets and Non-Attainment Review Approval; 40 CFR 52 Prevention of Significant Deterioration (PSD) Approval and Section 61 Findings.

These approvals are subject to a public comment period as specified in the Code of Federal Regulations, Title 40, Part

51.161 and the Commonwealth's Air Pollution Control Regulations 310 CMR 7.00: Appendix A. The Conditional Approval will allow for commencement of certain construction of the facility only, and provides information on the project description, emission control systems, facility limits, continuous emission monitors, record keeping, reporting and testing requirements. The Conditional Approval is necessary before construction can commence.

In addition to the requirements contained herein this facility is a major new source of air contaminants located in an attainment area and is subject to Federal Prevention of Significant Deterioration (PSD) regulations promulgated in 40 CFR Section 52.21.

The PSD program is implemented by the Department in accordance with the Department's "Procedures for Implementing Federal Prevention of Significant Deterioration Regulations". The Department is also issuing a PSD permit for this facility.

This facility was also subject to the requirements of the Massachusetts Environmental Policy Act (MEPA) MGL Chapter 30, Sections 61-62H. On July 17, 1998, the Secretary of Environmental Affairs issued a certificate that the Final EIR #11208 adequately complied with the Act and the Regulations governing the preparations of the EIR. A requirement for a Notice of Project Change in the July 17 Certificate was rescinded by the Secretary on August 14, 1998.

A FINAL APPROVAL is necessary before the facility can commence operation (approval of the final plans and specifications).

This approval is limited to the applicable Air Pollution Control Regulations and does not constitute approval as may be required by other Department regulations or statutes in order for the above mentioned facility to be installed and operated.

A list of submitted information pertinent to the application is delineated in Attachment A.

Yours truly,

Lee Dillard Adams
Deputy Regional Director
Bureau of Waste Prevention

Date: ______________
LDA/GWR/le

cc: See Attachment List

AIR QUALITY CONDITIONAL PLAN APPROVAL

I. FACILITY DESCRIPTION

A. Site Description

The project site consists of approximately 160 acres of land located approximately one-half mile directly east of the intersection of Blackstone and Elm Streets in Blackstone, Massachusetts. The development site is approximately three miles north of the Rhode Island border and located within an active sand and gravel mining operation. Blackstone is located in Worcester County in the south central area of the Commonwealth of Massachusetts. The neighboring community is a mix of industrial, commercial and residential land uses.

B. Project Description

The Permittee proposes to develop, construct and operate a combined-cycle electric generating facility in Blackstone, Massachusetts. The facility will consist of two parallel power trains, each including an ABB GT-24 gas turbine rated at approximately 180 megawatts (MW) output capacity (210 MW with steam augmentation), an unfired exhaust heat recovery steam generator, a steam turbine, an electric generator, air cooled condenser and auxiliary equipment.

Major auxiliary equipment associated with the facility includes a control room, CO oxidation catalysts, SCR catalysts for NO_x control, ammonia storage tanks, a continuous emission monitoring system (CEMs) and two small emergency diesel generators and one diesel fire pump and if necessary, natural gas preheater(s).

The turbine generators will have a total heat input capacity of approximately 3,630 MMBTU/hr (HHV) at an average ambient temperature of 59°F with no steam augmentation.

Maximum total heat input during steam augmentation will be 4,367 MMBTU/hr (HHV at 0°F ambient). The hot exhaust gases exiting the turbines will pass through two unfired heat recovery steam generators (HRSG) which will recover the heat from these gases to produce steam.

Steam produced in the HRSGs will be fed into two steam turbines to generate a nominal output of 190 MW (170 MW during steam augmentation) of electrical power. The HRSG will house an 80% efficient carbon monoxide (CO) catalyst at maximum continuous uncontrolled CO emissions (50% gas turbine load) followed by an ammonia injection grid and the selective catalytic reduction (SCR) catalyst for control of nitrogen oxides (NOx).

The facility will be designed to operate continuously (24 hours per day, 7 days per week) except for equipment downtime (to allow for servicing, maintenance and repair activities) and during low periods of electrical demand. Each turbine generator will utilize natural gas as the sole fuel, which will be fired at a maximum rate of 2,183,500,000 BTU per hour input while operating at 100% rated capacity at 0°F. There will be no backup fuel.

The emissions from each turbine will be emitted through individual new steel stacks, the tops of which shall be 180 feet above ground level and have an inside exit diameter of 18 feet which will provide for a maximum exit velocity of 63 feet per second at a temperature of 176°F under the maximum exhaust flow condition.

II. EMISSIONS

The operation of the turbine combustors on natural gas will result in emissions to the ambient air of the following air pollutants: Particulate Matter (PM), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOC's) and Ammonia (NH_3).

III. EMISSION LIMITS

A. Air Pollution emission rates from the facility shall be kept at the lowest practical level at all times, but shall not exceed the emission limitations as specified in Table 1 and Table 2.

B. Limits During Emergency or Malfunction

1. The Permittee shall be shielded from enforcement action brought for noncompliance with emission limitations specified in this permit as a result of an "emergency" and/or "malfunction". "Emergency" and "malfunction" are defined in Section XII of this permit.

2. An emergency and/or malfunction constitutes an affirmative defense to an action brought for noncompliance with emission limitations if the Permittee demonstrates the affirmative defense of emergency or malfunction through properly signed, contemporaneous operating logs and other relevant evidence that shows that:

   a) an emergency or malfunction occurred and that the cause(s) of the emergency or malfunction can be identified;

   b) the facility was at the time being properly operated;

c) during the period of the emergency or malfunction, the Permittee took all reasonable steps as expeditiously as possible to minimize levels of emissions that exceeded the emission standards, or other requirements in this permit; and

d) the Permittee submitted notice of the emergency or malfunction to the Department in writing within two (2) business days of the emergency or malfunction. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken.

3. In any enforcement proceeding, the Permittee has the burden of proof in establishing the occurrence of an emergency or malfunction.

4. If an emergency episode requires immediate notification to any government agencies, the Permittee shall make timely notification to the appropriate parties as required by law.

5. The Permittee shall not be shielded from enforcement for any emission exceedances which would result in a predicted exceedance of any health based air quality standards.

C. Annual Emissions -

The Permittee shall comply with the annual emissions referenced in Table 2 based on a rolling 12 month total.

D. Averaging Time -

The Permittee shall comply with the "lb/MMBtu", "ppm", and "lb/hr" emission limits referenced in Tables 1 and 2 based on a one hour block average.

E. Fuel Sulfur Limits -

The Permittee shall ensure that the sulfur content in natural gas does not exceed 0.8 grains per 100 ft^3 by monitoring as required in Section X of this Approval.

Table 1: ANP Blackstone Energy Company Stack Emission Limits [1].

Load % [2]	100				75				50				100 - with Steam Injection for Power Augmentation			
Ambient Temp F°	0	20	59	90	0	20	59	90	0	20	59	90	0	20	59	90
NO_x lb/hr	14.7	14.4	13.4	12.7	11.8	11.5	10.8	10.2	9.0	8.8	8.2	7.8	27.0	27.0	25.0	24.0
CO lb/hr	11.0	10.0	10.0	9.0	12.0	12.0	12.0	11.0	54.6	53.2	49.9	47.1	12.0	11.0	11.0	10.0
VOC lb/hr	3.6	3.5	3.3	3.1	2.9	2.8	2.6	2.5	3.9	3.8	3.6	3.4	9.8	9.5	8.9	8.5
PM lb/hr	23.9	23.3	21.8	20.6	19.1	18.6	17.4	16.5	14.6	14.2	13.3	12.6	26.2	25.4	23.8	22.6
SO_2 lb/hr	4.6	4.5	4.2	3.9	3.7	3.6	3.3	3.2	2.8	2.7	2.6	2.4	5.0	4.9	4.6	4.3
NH_3 lb/hr	5.4	5.2	4.9	4.6	4.3	4.2	3.9	3.7	3.3	3.2	3.0	2.8	5.9	5.7	5.4	5.1
NO_x lb/MMBtu	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0124	0.0128	0.0131	0.0132
CO lb/MMBtu	0.0055	0.0051	0.0055	0.0053	0.0075	0.0077	0.0083	0.0080	0.0449	0.0449	0.0449	0.0449	0.0055	0.0052	0.0058	0.0058
VOC lb/MMBtu	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018	0.0032	0.0032	0.0032	0.0032	0.0045	0.0045	0.0045	0.0045
PM lb/MMBtu	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
SO_2 lb/MMBtu	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023	0.0023
NH_3 lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
NO_x ppmvd 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	3.5	3.5	3.5	3.5
CO ppmvd @ 15% O_2	3.0	3.0	3.0	3.0	4.0	4.0	4.0	4.0	20.0	20.0	20.0	20.0	3.0	3.0	3.0	3.0
VOC ppmvd @ 15% O_2 [3]	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	2.5	2.5	2.5	2.5	3.5	3.5	3.5	3.5
NH_3 ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0

(1) Emission limits are on a per unit basis for each of two units.
(2) Emission limits at intermediate loads and temperatures are calculated based on linear interpolation of lb/MMBtu permit limits. Emission limits in lb/MMBtu are based on HHV. Optimization testing shall establish actual emission limits under the various load conditions.
(3) VOC expressed as CH_4 (methane).

Table 2: ANP Blackstone Energy Company Emissions Limits [1]

	Natural Gas without Steam Injection		Natural Gas with Steam Injection		Annual Emissions[4]
	lb/hr[2]	lb/MMBtu[3]	lb/hr[2]	lb/MMBtu[3]	tons/year
Sulfur Dioxide	4.6	0.0023	5.0	0.0023	40
Particulate Matter	23.9	0.012	26.2	0.012	209
Nitrogen Oxides	14.7 (2.0 ppmvd @ 15% O_2)	0.0074	27.0 (3.5 ppmvd @ 15% O_2)	0.0132	151[5]
Carbon Monoxide	54.6[6]	0.0449	12.0	0.0058	437
VOC[7]	3.9[6]	0.0032	9.8	0.0045	49[8]
Sulfuric acid	2.4	0.0012	2.6	0.0012	21
Ammonia	2.0 ppmvd @ 15% O_2		2.0 ppmvd @ 15% O_2		47[9]
Visible Emissions	Opacity no greater than 10%		Opacity no greater than 10%		

(1) Short-term emission limits specified in this table are per unit based upon one hour average unless otherwise specified and apply @ 50% load or greater. Emission limits for startup/shutdown shall be determined based on initial compliance test (see Condition XIII.7).

(2) Except where noted, hourly emission rates while burning natural gas are presented here based on 100% load and 0°F ambient temperature.

(3) The lb/MMBtu (pound per million Btu) emission limits are worst case values based on HHV. Allowable limits at each load and temperature condition are defined in Table 1 of this Conditional Approval.

(4) Annual emissions are facility-wide emissions and are based on a rolling 12-month total.

(5) Includes 3.0 tons from two emergency diesel generators and one diesel fire pump. The combustion turbine total annual NO_x emissions of 148 tpy corresponds to a rolling 12-month NO_x emission rate of 2.3 ppmvd @ 15% O_2.

(6) Worst case based on natural gas firing at 50% load and 0°F.

(7) VOC expressed as CH_4 (methane).

(8) Includes allowance for startup/shutdown and miscellaneous sources.

(9) Includes breathing and working losses of the ammonia storage tanks.

IV. MODELING ANALYSIS

An air quality impact analysis was performed to assess the impact of the proposed project on ambient air quality. The final results of the source interactive modeling data analysis submitted with the PSD permit application indicated that under no condition will the Permittee, by itself or with existing sources, violate the Federal or State ambient air quality standards or cause a condition of air pollution.

A. Air Toxics Analysis

1. The non-criteria pollutants include both Hazardous Air Pollutants (HAPs) as defined in Title III of the 1990 Clean Air Act Amendments, and "air toxics" regulated by Department policy. For air toxics, the Department has developed Threshold Effects Exposure Limits (TEL) and annual average Allowable Ambient Limit (AAL) values.

2. Ambient air concentrations of air toxics were determined by refined modeling for formaldehyde and for sulfuric acid and ammonia. All predicted impacts are within the TEL and AAL values.

3. The annual air toxics concentrations were based on a use of natural gas as the sole fuel. The predicted concentrations for air toxic materials from the facility exhaust stack are below TELs and AALs in all cases.

B. Accidental Release Modeling of Aqueous Ammonia.

1. Aqueous ammonia will be used as the reducing agent in the SCR system. The aqueous ammonia mixture will be stored on site in two storage tanks. The two tanks will be 13.1 feet in diameter by 14.8 feet in height with a combined total of 28,000 gallons storage capacity. In the event of an accidental spill, the aqueous ammonia solution would be pooled into a containment dike covered with a floating layer of ball-like baffles which reduce the liquid surface area by 91% and thus reduce the ammonia vaporization rate.

2. The vaporization and dispersion of the ammonia was modeled with receptors at the nearest fence line, approximately 50 meters to the northwest of the proposed aqueous ammonia tanks. Maximum predicted concentrations of ammonia were below the Immediately Dangerous to Life or Health (IDLH) thresholds at the fence line.

V. EMISSION OFFSETS AND NON-ATTAINMENT REVIEW

A. The town of Blackstone, Massachusetts, along with the entire Commonwealth of Massachusetts, is designated non-attainment for the pollutant ozone (O_3). Non-attainment review will apply for this project since potential emissions of Nitrogen Oxides (NOx) are above the "major source" threshold criteria of 50 tons per year, as defined in 310 CMR 7.00 Appendix A. NOx emissions are a precursor to the formation of ozone and are therefore regulated pursuant to 310 CMR 7.00, Appendix A. Applicable requirements for the proposed new major stationary source of NOx require the source to meet Lowest Achievable Emission Rate (LAER) and obtain emission offsets. The Permittee has proposed NOx emission limits of 2.0 ppmvd @ 15% O_2 for natural gas firing without steam injection, and 3.5 ppmvd @ 15% O_2 with steam injection for power augmentation. The Permittee will operate the facility in order to maintain a 12-month rolling average NOx limit of 2.3 ppmvd @ 15% O_2. These proposed NOx limits satisfy the Department's current determination for NOx LAER for combustion turbines.

B. Offset requirements for major sources of NOx in a "serious" ozone non-attainment region are required at a minimum ratio of 1.2 to 1. Rules for obtaining offsets in Massachusetts are set forth in regulation 310 CMR 7.00 Appendix A and Appendix B.

C. The Offset requirement for this facility can be met by withdrawing Massachusetts Department-certified Emission Reduction Credits (ERCs). Emission reduction credits can come from shutting down an existing source, or curtailing its operation, or by "over-controlling" an existing source. In all cases, offsets must be real, surplus, permanent, quantifiable, and federally enforceable. The Department will also accept NOx offsets created by qualifying activities in other states provided that the Department has executed a Memorandum of Understanding (MOU)or some other mutually acceptable agreement with the other state(s) and the offsets created in the other state are real, surplus, permanent, quantifiable, and federally enforceable.

D. In accordance with the requirements of 310 CMR 7.00: Appendix B(3) applicants must obtain five (5) percent more ERCs than the number of ERCs needed for offsets. This five (5) percent must be held as a "set aside" and neither sold nor used. In the case of the Permittee, they must obtain 1.26 times maximum facility NOx emissions or 190.3 tons of NOx. Offsets must be from the same non-attainment area or from another non-attainment area of equal or more severe non-attainment classification (if emissions from this other area contribute to ozone non-attainment in the area where the new project will be constructed).

E. ANP Blackstone Energy Company has agreements with Nantucket Electric Company (NEC) to obtain 145.3 tons per year (tpy) of certified NOx offsets from shutdown of the NEC Candle Street facility in Nantucket, Massachusetts for application to the ANP Blackstone Energy Project. These NEC offsets are from the total of 911.7 tpy of Rate Bank NOx ERCs certified by the Department on March 20, 1998 (Approval No.4B97058) for the shutdown of the NEC Candle Street facility. ANP Blackstone Energy Company also has an agreement with Simkins Paper Company (SPC) to obtain 45.0 (tpy) of certified NOx offsets from shutdown of the various boilers at Westfield River Paper Company (WRPC) in Russell, Massachusetts and Lee, Massachusetts for application to the ANP Blackstone

Energy Project. These SPC offsets include 43.0 tpy of NOx ERCs certified by the Department on January 9, 1997 (Approval No.1-C-94-122) from shutdown of Boilers 1,2,and 3 at WRPC in Russell, Massachusetts, aand 2.0 tpy of a total of 12.0 tpy of NOx ERCs certified by the Department on January 9, 1997 (Approval No.1-C-94-121) from shutdown of Boilers 1 and 2 at WRPC in Lee, Massachusetts. The total number of NOxERCs being obtained for the ANP Blackstone Energy Project (145.3 tpy from NEC and 45.0 tpy from SPC) are proposed to fulfill the requirement for 190.3 tpy of NOx offsets as required by 310 CMR 7.00 Appendices A and B. These NOx ERCs must be surrendered by ANP Blackstone Energy Company to the Department prior to the commencement of operation of the facility. With approval of the Department, other ERCs which are equivalent may be surrendered.

VI. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The Permittee is considered an electric utility stationary gas turbine since more than one third of its net electrical output will be sold. The New Source Performance Standards (NSPS) for gas turbines, Title 40 Part 60 Subpart GG of the Code of Federal Regulations, will be applicable to the facility. The NSPS restricts NOx emissions to a nominal value of 75 ppm (approximately equivalent to 0.3 lb/MMBTU) for an electric utility gas turbine of 100 MMBTU/hr heat input or greater. The Permittee will meet this limit through its proposed dry low-NOx combustion technology in conjunction with SCR add-on NOx controls. Subpart GG also has sulfur restrictions which will be met by using natural gas.

VII. TITLE IV SULFUR DIOXIDE ALLOWANCES AND MONITORING

A. According to 40 CFR Part 72, the Permittee will be designated as a Phase II Acid Rain "New Affected Unit" on January 1, 2000 or 90 days after commencement of activities, whichever comes later, but not after the date the facility declares itself commercial. The application for the Permittee is due 12 months before the commencement of operation.

B. The Acid Rain Program effects reductions of SO_2 by allocating a limited number of marketable allowances primarily to existing power plants and by requiring all plants, including new plants that were not allocated allowances, to hold or obtain allowances to offset their annual actual SO_2 emissions. Allowances are available through the Chicago Board of Trade and other sources and will be secured by the Permittee. The first date to hold allowances for the facility will be January 30, 2001.

C. The Permittee will also be required to have a Designated Representative (DR) and to install a Continuous Emissions Monitoring System for each of the two units. The DR is the facility representative responsible for submitting required permits, compliance plans, emissions monitoring reports, offset plans, compliance certification, and is the responsible official with regards to all matters under the Acid Rain Program. The continuous emission monitoring requirements are specified in 40 CFR Part 75 for monitoring SO_2, NO_x and CO_2 emissions as well as volumetric flow of the flue gas. As an option, EPA allows gas fired facilities to conduct fuel sampling and analysis and fuel flow monitoring in place of SO_2 continuous emissions monitoring and flue gas flow monitoring. Natural gas fired units complying with 40 CFR 75.14(c) are exempt from the opacity monitoring requirements. In addition, pursuant to 40 CFR 75.13, CO_2 emissions may be estimated in accordance with 40 CFR part 75 Appendix G, in lieu of installing a CO_2 CEMs.

VIII. NOISE REQUIREMENTS

A. BACKGROUND:

Daytime and nighttime sound measurements were taken at six locations around the site. The sound measurements consisted of both A-weighted sound pressure levels and octave band.

Department Policy 90-001 provides that an increase in sound by more than 10 dBA over the existing L_{90} ambient level, unless otherwise specified, may be considered a violation of the air quality regulations. Additionally, "pure tone" sounds defined as any octave band level, which exceeds the levels in adjacent octave bands by 3 dBA or more, may also be prohibited.

The Department may exercise its discretion to allow a sound increase above the 10 dBA despite the use of extensive sound control measures. This may occur when the impact is at an area where residents or other sensitive receptors are not located at the time the permit is issued, and will not be allowed to be located there in the future.

B. NOISE LIMITS:

1. The facility shall be designed, constructed, operated and maintained such that at all times:
(a) No condition of air pollution will be caused by emissions of sound as provided in 310 CMR 7.01;
(b) No sound emissions resulting in noise will occur as provided in 310 CMR 7.10 and the Department's Policy 90-001;and
(c) Other than approved herein, sound emissions will not exceed the levels set forth in Table 3 at the locations as identified in said Table 3.

2. The allowable ambient noise levels generated from the operation of the facility are summarized in Table 3 of this CONDITIONAL APPROVAL.

TABLE 3								
NOISE LEVELS AT NOTED LOCATIONS								
Reception Location*	Current Background Ambient (L90, dBA)		Plant Generated Noise dBA	Maximum Allowable Ambient (dBA) Day/night Increase Not to be Exceeded				
				Ambient dBA		Increase		
	Night	day		Night	Day	Night	Day
R-1	30	30	36	37	37	7	7
R-2	29	36	38	39	40	10	4
R-3	28	31	38	38	39	10	8
R-4	29	30	34	35	35	6	5
PL-1		32	50		50		18
PL-2		32	43		43		11
PL-3		32	53		53		21

*PL-1 represents NW property line segment proximate to Fish Pond oriented at S43°28'46"W.
PL-2 represents E property line point where segment oriented at 73°34'10"E intersects northwest corner of parcel designated as Map 31 Lot 4.
PL-3 represents SE property line segment oriented at N68°43'25"E.
All noise-receptor locations are as presented in the Air Quality plan application dated December 22, 1997 and amended June, 1998 unless otherwise noted.

3. The Permittee has secured from the two abutting owners of the sand and gravel operation (receptor locations PL-1, 2 and 3) a Land Use and Restriction (the "Easement and Restriction") that prohibits the establishment of, without limitation, the following types of structures: single or multiple family dwellings, residential condominiums, hospitals, nursing homes, assisted living facilities, dormitories, schools or pre-schools or similar sensitive receptors.

The Easement and Restriction between the Permittee and abutting owners Kimball Sand Company, Inc. and Robert W. Kimball, Trustee of SAK Realty Trust, will be recorded in the Worcester County Registry of Deeds, in a form approved by the Department, prior to the commencement of operation of the facility and will be enforceable against the current and future owners. An executed copy of said Easement and Restriction shall be submitted to the Department (CERO BWP Permit Section) upon execution and recording prior to commencement of operation. Permittee shall not amend, modify, assign or terminate the Easement and Restriction prior to final decommissioning of the facility without the express written consent of the Department. Permittee shall fully maintain and enforce the Easement and Restriction against the abutting owners to prevent any violation thereof by any present or future abutting owner. The Permittee shall take all actions necessary to enforce the Easement and Restriction upon notice from the Department that it considers activities on the abutting property to be inconsistent with the terms and conditions of the Easement and Restrictions.

C. SOUND MONITORING:

1. The Permittee shall submit a post construction ambient sound monitoring protocol to the CERO Permit Section within 60 days of this approval. The protocol is subject to DEP approval. The Protocol shall include the following minimum requirements:

1] Monitoring shall be conducted for one day per month for 12 months after commencement of commercial operation of the facility;
b] Monitoring shall commence within 30 days of commercial operation of the facility;
2] Monitoring shall be for a continuous time period 24 hours per day;
3] Monitoring shall be for L90, octave band center frequency and third octave band;
4] All readings shall be stored on a data logger in disc or similar digital format. Strip chart recordings shall also be maintained;
5] Monitoring shall be conducted by a suitably qualified noise abatement specialist using state of the art noise monitoring equipment;
6] Each month's monitoring results shall be submitted to the CERO Permit section within 30 days of completion of the monitoring period;
7] Monitors shall be set up as close as possible to the same locations as the baseline monitors around the facility;
8] The Department reserves the right to require the relocation of or addition of monitors or require additional monitoring periods if in the opinion of the Department it is necessary to determine compliance with the Air Pollution Control Regulations.

2. The Permittee shall at a minimum, unless otherwise ordered by the Department or as required under section III, conduct monitoring in accordance with the Department approved protocol.

D. NOISE ABATEMENT EQUIPMENT AND PROCEDURES:

The following plant equipment may be a source of significant sound emissions unless properly controlled: the intakes and exhaust of two 180 MW combustion turbines, two air cooled condensers, two heat recovery steam generators, two turbine buildings and their associated ventilation systems, two main transformers, two circulating-cooling-water coolers, the gas compressor building, steam lines, gas lines and steam release vents. In addition, other sources of sound at the facility may include various water pumps, piping and valves, building openings, fans, and on site communication systems.

The facility shall be designed with the following noise mitigation measures:

1] TRANSFORMERS - Transformers shall have concrete walls on at least three sides. The face of the concrete walls shall be constructed in such a manner as to provide sound mitigation, reduce sound reflection and be consistent with state of the art[1] sound attenuation;

2] BUILDING DOORS shall be kept closed at all times except for when they are being used for specific entry or exit. Doors shall be of solid design;

3] All VENTILATION OPENINGS to the turbine building and any buildings or enclosures designed and installed for sound attenuation shall be equipped with state of the art sound attenuation mufflers or baffles;

4] GAS TURBINES AND STEAM TURBINES shall be contained within a structure specifically designed to attenuate sound. The walls of these structures shall be made of state of the art sound attenuation material to minimize sound that could be emitted from these sources. The Gas turbine intakes shall be equipped with Grade G silencers or better;

5] All ON SITE GAS SUPPLY LINES shall be buried under ground, contained within state of the art acoustically treated structures, or specifically constructed with state of the art sound attenuation materials to prevent these sources from causing a pure tone or tonal sound audible off property;

6] All HIGH PRESSURE STEAM lines shall be buried under ground, contained with state of the art acoustically treated structures, or specifically constructed with state of the art sound attenuation materials. The natural gas pipelines from the gas compressor building to the gas turbines will be buried; the main steam lines from the HRSGs to the steam turbine buildings will be enclosed;

7] HEAT RECOVERY STEAM GENERATOR design shall include a silencer with gas turbine exhaust duct cladding and state of the art noise attenuation cladding as necessary. HRSG high-pressure feedwater and recirculation pump design shall include pumps enclosed in a building with sound absorbing

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[1] STATE OF THE ART sound abatement means and measures shall mean for purposes of this approval the use of means and measures that will provide the best sound abatement for the equipment, process or source noted herein as recognized by current engineering principles and practices at the time of construction necessary to meet the requirements of the permit. Means and measures of sound abatement shall be considered equivalent if they provide for no different then two-dBA noise reductions at the equivalent distance.

cladding. The HRSG may also be enclosed by state of the art sound attenuation walls and roofing if determined necessary by the proponent;

8] TURBINE Exhausts shall be equipped with state of the art sound attenuating mufflers;

9] ALL STEAM RELEASE VENTS [normal and emergency] shall be fitted with sound abatement mufflers capable of preventing sound that exceeds 85 dBA as measured at 15 feet from the source prior to the initial testing and start up;

9a] NON-EMERGENCY STEAM RELEASES shall be conducted only during day light hours. ANP shall notify the DEP/CERO and the Boards of Health in the Towns of Blackstone and Mendon at least 24 hours before such non-emergency releases are to be conducted;

10] DRY COOLING TOWERS shall be designed and constructed using the state of the art sound abatement features with low noise fans and motors;

11] AIR COOLED CONDENSERS shall be designed and constructed using low noise fans with noise reduction motors;

12] PERIMETER BERMS, noise abatement walls and other site specific sound minimization features may be employed as necessary to minimize property line sound levels from the facility;

III. RESPONSE TO NON-COMPLIANCE

1. Upon receiving information that the facility may be in non-compliance with the provisions of this permit regarding sound emission levels, the Permittee shall take the following immediate actions:
   (a) Notify the BWP CERO Compliance and Enforcement Section by telephone or fax;
   (b) Verify whether non-compliance occurred and is continuing
   (c) Take all reasonable interim steps to eliminate or minimize sound emissions to return to compliance.

2. Should non-compliance with this permit or the Department's regulations due to sound emissions from the facility affecting one or more residences occur despite the interim steps implemented above, the Permittee shall, unless otherwise ordered by the Department, submit within 30 days of receipt of information of non-compliance from the Department or other credible source, whichever is earlier, a sound reduction plan which sets out the additional monitoring and remedial actions it proposes to implement in order to verify a return to compliance, and a schedule for the commencement and completion of each major component of

the monitoring and remedial actions.

3. Except as otherwise ordered by the Department, the schedule for completion of the remedial actions shall not exceed thirty days (30) from the Department's approval of the above plan, or applicable part(s) thereof, unless the Permittee adequately demonstrates that the work cannot be completed within thirty days using its best efforts. In reviewing a best efforts demonstration the Department will not consider delays that could have been reasonably avoided had the facility been designed and constructed in manner to facilitate the timely completion of the proposed remedial actions, including, for example, installation of additional sound reduction equipment, sound containment structures or other sound barriers.

4. If the remedial actions are not completed in accordance with the schedule established by the Department and there is continuing non compliance with the sound emission levels established in this permit or in regulation at one or more residences, the Permittee shall, unless otherwise ordered by the Department, modify the operations of the facility in order to return to compliance including, as necessary, reduction of the facility's operating capacity, restriction of its hours of operations, or suspension of operations. The modifications shall commence on the first day beyond the established completion date and continue until the operator certifies in writing to the Department that all the remedial actions are completed.

5. Nothing is this permit shall be interpreted to restrict, limit or in anyway impair the Department's authority to institute such administrative or judicial enforcement actions as it deems necessary in response to non-compliance with the terms and provisions of this permit or the Department's regulations.

IX. <u>SPECIAL CONDITIONS</u>

1. The Permittee shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(2)(a), plans and specifications for the exhaust stacks, combustion turbine generators, the SCR control systems (including the handling and storage system), the CO catalyst control systems, facility plans, and the Continuous Emissions Monitoring System once the specific information has been determined.

2. The Permittee requires Department written approval prior to commencing installation of these system components.

3. The Permittee shall properly train all personnel to operate the facility and control equipment in accordance with vendor specifications. All persons responsible for the operation of the ammonia handling and SCR control systems shall sign a

statement affirming that they have read and understand the approved standard operating and standard maintenance procedures. This training shall be updated at least once annually. Department personnel shall be informed of scheduled training sessions at least 30 days in advance and Department personnel shall have the ability to attend these training sessions.

4. The Permittee shall allow the gas turbine to operate at less than 50% power only during start ups and shutdowns. Operation at these loads is limited to no more than 3 hours duration for each start up and shutdown.

5. The Permittee shall ensure that the SCR control equipment for the turbine generator is operational whenever the turbine is operated at 50% power or greater.

6. The Permittee shall maintain, in the facility control room, portable ammonia detectors for use during a spill or atmospheric release.

7. The Permittee shall at all times keep enough of the ball-like plastic baffles within the containment area around the aqueous ammonia storage tanks to provide 91% surface coverage of any spilled aqueous ammonia. The balls must be free of ice and other restrictions that would inhibit their floatation.

8. The aqueous ammonia storage tanks shall be equipped with high and low level audible alarm monitors.

9. The Permittee shall store the standard operating and maintenance procedures for the ammonia handling system in a convenient location (control room/technical library) and make them readily available to all employees.

10. The Permittee shall maintain on-site for the CEMs an adequate supply of spare parts to maintain the on-line availability and data capture requirements.

11. Within sixty (60) days after commercial operation of the facility, the roadways will be paved and maintained to prevent dust emissions.

12. Within one year of commencement of operation, the Permittee shall file an application for an operating permit pursuant to Regulation 310 CMR 7.00, Appendix C.

13. American National Power Inc., 100% owner of the Permittee, shall, prior to commencement of construction, transfer ownership of a minimum of 190.3 tons per year of NOx emission reduction credits, acquired for use as emission offsets for this project, to the Permittee.

14. The Permittee shall comply with all applicable operational standards contained in 40 CFR Part 72 and 75, 40 CFR 60, and 310 CMR 7.27.

15. The Permittee shall comply with all provisions of 40 CFR Parts 72 and 75, 40 CFR 60, and 310 CMR 6.00-8.00 that are applicable to this facility.

16. The Permittee shall comply with the requirements of Regulation 310 CMR 7.27 (NOx Budget Rules).

X. MONITORING AND RECORDING REQUIREMENTS

1. The Permittee shall install, calibrate, test and operate a Data Acquisition System(s) (DAS) and stack continuous emission monitors (CEMs) to measure and record the following:

   a) Oxygen (O_2)
   b) Oxides of Nitrogen (NO_x)
   c) Carbon Monoxide (CO)
   d) Ammonia (NH_3)

2. The Permittee shall ensure that all stack monitors and recording equipment comply with Department approved performance and location specifications, and conform with the EPA monitoring specifications in 40 CFR Part 60.13 and 40 CFR Part 60 Appendices B and F, and all applicable portions of 40 CFR Parts 72 and 75.

3. The Permittee shall use and maintain its CEM system as "direct-compliance" monitors to measure NO_x, CO, O_2 and Ammonia. "Direct-compliance" monitors generate data that legally documents the compliance status of a source. The Department shall utilize the data generated by the "direct-compliance" monitors for compliance and enforcement purposes.

4. The Permittee shall comply with all the applicable monitoring requirements contained in 40 CFR Parts 72 and 75 (Acid Rain Program), and 310 CMR 7.27 (NO_x Budget Rules).

5. The Permittee shall equip the CEMs with audible and visible alarms to activate when emissions exceed the limits established in Table 1 and Table 2 of this Conditional Approval.

6. The Permittee shall operate each CEM at all times except for periods of CEM calibration checks, zero and span adjustments, preventive maintenance, and periods of malfunction.

7. The Permittee shall obtain and record emission data from each CEM for at least 75% of the emission unit operating hours per day, for at least 75% of the emission unit operating hours per month, and for at least 95% of the emission unit operating hours per quarter, except for periods of CEM calibration checks, zero and span adjustments, and preventive maintenance.

8. All periods of excess emissions, even if attributable to an emergency/malfunction, startup/shutdown or equipment cleaning, shall be quantified and included in the determination of annual emissions and compliance with the annual emission limits as stated in Table 2 of this Conditional Approval.

9. The Permittee shall determine continuous compliance with the VOC emission limits (short-term and annual) contained herein by monitoring CO emissions with the CO CEM.

10. Any period of excess emission of CO shall count as a period of excess emission of VOC, and the excess emission of VOC shall be accumulated towards the 49 tons per year annual emission limitation for VOC.

11. If the gas turbine is operating below 50% load, the VOC emissions shall be considered as occurring at the rate determined in the initial stack test for startup.

12. If the gas turbine is operating at 50% load or greater, and if CO emissions are below the CO emission limit at the given gas turbine operating conditions, the VOC emissions shall be considered as meeting the emission limits contained in this Conditional Approval to Construct.

13. If the gas turbine is operating at 50% load or greater, and if CO emissions are above the CO emission limit at the given gas turbine operating conditions, the VOC emissions shall be considered as occurring at a rate determined by the equation:

$$VOC_{actual}=VOC_{limit}(CO_{actual}/CO_{limit}).$$

14. The Permittee shall monitor and record the Sulfur and Nitrogen content in natural gas on a daily basis, or pursuant to any alternative fuel monitoring schedule issued for the facility in accordance with 40 CFR Part 60, Subpart GG 60.334(b)(2).

15. The Permittee shall install and operate continuous monitors and alarm systems to monitor temperature at the inlet to the SCR and CO catalysts.

16. The Permittee shall not be subject to pre-construction monitoring as specified in 40 CFR Part 52.21(m).

17. The Permittee shall develop a quality control/quality assurance (QA/QC) program for the long-term operation of the CEMs which conforms to 40 CFR Part 60, Appendix F, all applicable portions of 40 CFR Parts 72 and 75, and 310 CMR 7.27 (NOx Budget Rules). The program must be submitted in writing, reviewed and approved in writing by the Department before the facility begins commercial operations. Any subsequent changes may only be done with approval from the Department.

XI. RECORD KEEPING REQUIREMENTS

1. A record keeping system shall be established and maintained on site by the Permittee. All records shall be maintained up-to-date such that year-to-date information is readily available for Department examination. Record keeping shall, at a minimum, include:

   a) Compliance records sufficient to demonstrate that emissions have not exceeded what is allowed by this Conditional Approval.

      Such records may include daily production records, raw material usage rates, fuel purchase receipts, emissions test results, monitoring equipment data and reports.

   b) Maintenance: A record of routine maintenance activities performed on the emission unit, control equipment and monitoring equipment including, at a minimum, the type or a description of the maintenance performed and the date and time the work was completed.

   c) Malfunctions: A record of all malfunctions on the emission unit, control device and monitoring equipment including, at a minimum: the date and time the malfunction occurred; a description of the malfunction and the corrective action taken; the date and time corrective actions were initiated; and the date and time corrective actions were completed and the emission unit returned to compliance.

2. The Permittee shall maintain for the life of the facility all operating and monitoring records and logs. The Permittee shall make available to the Department for inspection upon request the five most recent years of data.

3. The Permittee shall maintain records on natural gas to record the sulfur content daily or at the frequency required pursuant to any alternative fuel monitoring schedule issued for the facility by the Department in accordance with 40 CFR Part 60, Subpart GG 60.334(b)(2).

4. The Permittee shall maintain on-site necessary permanent records of output from all continuous emission monitors for flue gas emissions, fuel consumption, SCR and CO control

system inlet temperatures, and turbine inlet and ambient temperatures, and shall make these records available to the Department on request.

5. The Permittee shall maintain a log to record problems, upsets or failures associated with the emission control system, CEMs, or the ammonia handling system.

6. The Permittee shall comply with all applicable record keeping requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, and 310 CMR 7.27.

XII. REPORTING REQUIREMENTS

A. EMERGENCY OR MALFUNCTION -

The Permittee shall provide notice of an emergency or malfunction that:

1) cause emissions to the ambient air that exceed any emission limits including noise limits contained herein; or

2) cause the release or the threat of a release of ammonia, and/or upsets or malfunctions to the ammonia handling or delivery systems; or

3) cause a condition of air pollution;

to the Department of Environmental Protection, Central Regional Office, Bureau of Waste Prevention, Compliance & Enforcement Section within four hours (or as soon as reasonably practical) of the emergency or malfunction and in writing within two (2) business days of the emergency or malfunction. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken. The Permittee must comply with all notification procedures required under M.G.L. c. 21E, Spill Notification Regulations.

B. MONTHLY REPORTS -

The Permittee shall submit a monthly report in writing and in digital format to the Department of Environmental Protection, Central Regional Office, 627 Main Street, Worcester, Massachusetts, 01608. The report will be submitted by the 15th of the following month and will contain at least the following information:

a) The monthly reports from the facility CEMs shall identify any periods of excess emissions in a format acceptable to the Department.

b) For each period of excess emissions or excursions from allowable operating conditions, the Permittee shall list the duration, cause, the response taken, and the amount of excess emissions.

Periods of excess emissions should include periods of start-up, shutdowns, malfunction, emergency, equipment cleaning, and upsets or failures associated with the emission control system or CEMs.

"Emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of this source, including acts of God, which would require immediate corrective action to restore normal operation, and that causes the source to exceed a technology based limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operations, operator error or decision to keep operating despite knowledge of these things.

"Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

c) A tabulator of periods of operation (dispatch).

C. The Permittee shall comply with all applicable reporting requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, and 310 CMR 7.27.

D. In accordance with 310 CMR 7.12(7), the facility shall register, on a form obtained from the Department such information as the Department may specify including:

a) The nature and amounts of emissions from the facility.

b) Information which may be needed to determine the nature and amounts of emissions from the facility.

c) Any other information pertaining to the facility which the Department requires.

d) Information required by 310 CMR 7.12(1)(a) shall be submitted annually.

XIII. TESTING REQUIREMENTS

1. The facility shall be constructed to accommodate the emissions testing requirements contained herein. All emissions testing will be conducted in accordance with the Department's "Guidelines for Source Emissions Testing" and in accordance with the Environmental Protection Agency tests as specified in the 40 CFR Part 60, Appendix A, 40 CFR Part 60 Subpart GG, 40 CFR Parts 72 and 75, or by another method which has been correlated to the above method to the satisfaction of the Department.

2. All emission testing must be conducted within 180 days after initial start up of the turbine generator.

3. The Permittee must obtain approval of the emission testing protocol. A detailed description of sampling port locations, sampling equipment, sampling and analytical procedures, and operating conditions for such tests must be submitted to the Department of Environmental Protection, 90 days prior to testing of the facility.

4. Preliminary results of the emission testing must be submitted within 30 days of completion to the Department of Environmental Protection, 627 Main Street, Worcester, Massachusetts.

5. A Final test report must be submitted in writing and in digital format within 60 days of completion to the Department of Environmental Protection, 627 Main Street, Worcester, Massachusetts, 01608..

6. The Permittee shall conduct compliance testing to demonstrate compliance with the emission limits (lb/hr, lb/MMBtu and ppmvd and opacity) as specified in Table 1 for the pollutants listed in Table 4.

7. The Permittee shall conduct optimization testing to determine the lowest practicable emission rates for each of the pollutants noted in table 1 and 2 and the operating conditions necessary to achieve and maintain these emission rates. The Department reserves the right to require compliance with these optimized rates as demonstrated by operating practice of the facility.

TABLE 4 POLLUTANTS*
Particulate Matter (PM)
Volatile Organic Compounds (VOC)
Nitrogen Oxides (NO_x)
Sulfur Dioxide (SO_2)
Ammonia (NH_3)
Carbon Monoxide (CO)
Opacity
* The testing of the pollutants will be conducted utilizing natural gas at 50%, 75% and 100% base load (all without steam injection), and 100% load with steam injection.

8. The Permittee shall conduct emission optimization tests for "start-up" and "shut down" periods for each combustion urbine. Emission data generated from this testing shall be reviewed by the Department prior to determining and approving the maximum allowable emission rate limits (lb/event), including opacity limits, for these periods of time. The Department shall incorporate the emission limits into a Final Approval for this facility upon issuance and shall consider such limits enforceable. The above testing shall include the pollutants listed in Table 4.

9. The Permittee shall have the right to obtain lower VOC emission limits on the basis of the stack test results. The VOC limits contained in Tables 1 and 2 of this Conditional Approval will be so revised consistent with the stack test results, if so requested by the Permittee and/or as required by the Department.

10. In accordance with 310 CMR 7.04(4)(a), the Permittee shall have the fuel utilization facility inspected and maintained in accordance with the manufacturer's recommendations and tested for efficient operation at least once in each calendar year. The results of said inspection, maintenance and testing and the date upon which it was performed shall be recorded and posted conspicuously on or near the permitted equipment.

11. In accordance with 310 CMR 7.13 the Department may require emission testing at any time to ascertain compliance with the Department's Regulations or design approval provisos.

12. The Permittee shall comply with the test methods noted in Table 5 in accordance with requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, and 310 CMR 7.27:

TABLE 5	
POLLUTANT	**TEST METHOD**
NO_x	Method 20
CO	Method 10 (gas filter (GFC) correlation method)
VOC	Methods 25A and 18
Opacity	Method 9
SO_2	Method 20 (fuel test option)
PM	Method 5

13. The Permittee shall conduct initial and annual stratification testing in accordance with Method 20 for NO_x as well as O_2. The purpose of these tests shall be to document a representative CEM sampling location for NO_x in accordance with annual RATA testing as well as to satisfy Method 20 initial testing requirements.

XIV. GENERAL REQUIREMENTS

1. All requirements of this PROPOSED CONDITIONAL APPROVAL which apply to the Permittee shall apply to all subsequent owners and/or operators of the facility.

2. SUSPENSION - This approval may be suspended, modified, or revoked by the Department if, at any time, the Department determines that the facility is violating any condition or part of the approval.

3. OTHER REGULATIONS - This approval does not negate the responsibility of the owner/operator to comply with this or any other applicable federal, state, or local regulations now or in the future. Nor does this approval imply compliance with any other applicable federal, state or local regulation now or in the future.

4. DUST AND ODOR - The facility shall be operated in a manner to prevent the occurrence of dust or odor conditions which cause or contribute to a condition of air pollution as defined in Regulation 310 CMR 7.01 and 7.09.

5. ASBESTOS - Should asbestos remediation/removal be required as a result of this Approval, such asbestos remediation/removal shall be done in accordance with Regulation 310 CMR 7.15.

6. MODIFICATIONS - Any proposed increase in emissions above the limits contained in this Proposed Conditional Approval must first be approved in writing by the Department pursuant to 310 CMR 7.02.

In addition, any increase may subject the facility to additional regulatory requirements.

7. REMOVAL OF AIR POLLUTION CONTROL EQUIPMENT - No person shall cause, suffer, allow, or permit the removal, alteration or shall otherwise render inoperative any air pollution control equipment or equipment used to monitor emissions which has been installed as a requirement of 310 CMR 7.00, other than for reasonable maintenance periods or unexpected and unavoidable failure of the equipment, provided that the Department has been notified of such failure, or in accordance with specific written approval of the Department.

XV. CONSTRUCTION REQUIREMENTS

During the construction phase, facility personnel shall take reasonable precautions (noted below) to minimize air pollution episodes (dust, odor, noise, etc.).

1. Facility personnel shall exercise care in operating the noise generating equipment (mobile power equipment, power tools, etc.) to prevent a potential noise problem.

2. Construction vehicles transporting loose aggregate to or from the facility shall be covered and in containers that prevent aggregate from escaping.

3. The construction open storage areas, piles of soil and loose aggregate, shall be covered or watered down as necessary to minimize dust emissions.

4. Any spillage of loose aggregate and dirt deposits on the public roadway, leading to/or from the facility shall be removed during the next business day or as necessary. (A mobil mechanical sweeper equipped with a water spray is an acceptable method to minimize dust emissions).

5. On site unpaved roadways/excavation areas subject to vehicular traffic shall be watered down as necessary or treated with the application of a dust suppressant to minimize the generation of dust.

XVI. SECTION 61 FINDINGS

Pursuant to G.L. c. 30 sec. 61 of the Massachusetts Environmental Policy Act, (MEPA), 301 CMR 11.12 of the MEPA Regulations, and the Secretary's Certificate of finding on the final EIR, dated July 17, 1998 (ENF #11208) the Department's Section 61 Findings on "ANP Blackstone Energy Project" dated __________, determining that all feasible measures have been taken to avoid or minimize impacts to the environment, is attached as "Exhibit B" and incorporated by reference into this permit.

See Attachment B of This Approval Letter.

ATTACHMENT "A"

LIST OF PERTINENT INFORMATION FOR TRANSMITTAL #118969

Name of Facility: ANP Blackstone Energy Company

Location: Elm Street, Blackstone, Massachusetts

Submitted By: Earth Tech, Inc.

Attested To By: George S. Lipka, P.E. Number 29704

a) PSD/NSR Air Plan Approval Application
Date Received: December 23, 1997

b) PSD/NSR Air Plan Approval
Application Addendum
Date Received: June 23, 1998

c) ANP Blackstone Energy Company
Plant North Elevation

d) Site Layout - Drawing No. 1AHV00923
Drawing No: 1AHV00923

List of cc's

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Planning Commission
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John Courcier
U.S. EPA - Air Permits
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Craig Goff, DEP/WERO
Dave Howland, DEP/WERO

5

AMTEST
AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: CLR\00-087WD\M4NH$_3$\SUMR10-12
Client: General Electric @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	75% Load Condition HRSG STACK OUTLET				
	RUN #10	RUN #11	RUN #12	AVERAGE	BLANK
Lab #:	6583	6584	6585		
Date:	8/9/00	8/9/00	8/9/00		
M4 Start Time:	0112	0157	0237		
M4 Stop Time:	0142	0227	0307		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	35.90	36.11	36.43	36.15	
Volume Sampled (dscf):	14.067	14.836	14.465	14.456	14.456
Volume Sampled (dscm):	0.398	0.420	0.410	0.409	0.409
Oxygen (percent):	14.2	14.1	14.2	14.2	14.2
Average Observed Barometric Pressure ("Hg):	29.95	29.95	29.95	29.95	29.95
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	66	65	64	65	65
Observed Relative Humidity on Test Day (percent):	79	80	81	80	80
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0108	0.0104	0.0102	0.0105	0.0105
Stack Gas Airflow (dscf/min):	634608	632837	645582	637676	637676
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	334	350	364		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.7	1.8	1.8		1.5
Ammonia In Impinger Solution (µg):	10	8	12	10	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.010	0.008	0.012	0.010	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.025	0.019	0.029	0.024	< 0.002
Ammonia Emission Concentration (ppm):	0.035	0.027	0.041	0.035	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.031	0.023	0.036	0.030	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.038	0.029	0.044	0.037	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.033	0.025	0.039	0.032	< 0.002
Ammonia Emission Rate (lb/hr):	0.060	0.045	0.071	0.058	< 0.001
Ammonia Emission Rate (tons/yr):	0.262	0.198	0.310	0.256	< 0.006

AMTEST
AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: CLR\00-087WD\M4NH$_3$\SUMR7-9
Client: General Electric @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	85% Load Condition HRSG STACK OUTLET				
	RUN #7	RUN #8	RUN #9	AVERAGE	BLANK
Lab #:	6580	6581	6582		
Date:	8/8/00	8/8-9/00	8/9/00		
M4 Start Time:	2254	2341	0025		
M4 Stop Time:	2324	0011	0055		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	39.40	40.62	41.04	40.35	
Volume Sampled (dscf):	14.838	14.908	21.500	17.082	17.082
Volume Sampled (dscm):	0.420	0.422	0.609	0.484	0.484
Oxygen (percent):	14.1	14.2	14.2	14.2	14.2
Average Observed Barometric Pressure ("Hg):	29.95	29.95	29.95	29.95	29.95
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	69	67	67	68	68
Observed Relative Humidity on Test Day (percent):	71	79	78	76	76
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0106	0.0114	0.0113	0.0111	0.0111
Stack Gas Airflow (dscf/min):	735688	755632	752638	747986	747986
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	362	398	356		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.8	2.0	1.8		1.5
Ammonia In Impinger Solution (µg):	18	15	21	18	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.018	0.015	0.021	0.018	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.043	0.036	0.034	0.038	< 0.002
Ammonia Emission Concentration (ppm):	0.061	0.050	0.049	0.053	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.053	0.044	0.043	0.047	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.064	0.054	0.052	0.057	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.055	0.047	0.046	0.050	< 0.002
Ammonia Emission Rate (lb/hr):	0.118	0.101	0.097	0.105	< 0.001
Ammonia Emission Rate (tons/yr):	0.517	0.441	0.426	0.462	< 0.006

AMTEST
AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: CLR\00-087WD\M4NH3\SUMR4-6
Client: General Electric @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	95% Load Condition HRSG STACK OUTLET				
	RUN #4	RUN #5	RUN #6	AVERAGE	BLANK
Lab #:	6577	6578	6579		
Date:	8/8/00	8/8/00	8/8/00		
M4 Start Time:	0319	2105	2151		
M4 Stop Time:	0349	2129	2221		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	43.45	63.93	64.37	57.25	
Volume Sampled (dscf):	15.639	14.723	15.316	15.226	15.226
Volume Sampled (dscm):	0.443	0.417	0.434	0.431	0.431
Oxygen (percent):	14.0	13.8	13.8	13.9	13.9
Average Observed Barometric Pressure ("Hg):	29.95	29.95	29.95	29.95	29.95
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	64	75	72	70	70
Observed Relative Humidity on Test Day (percent):	69	60	67	65	65
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0086	0.0111	0.0110	0.0102	0.0102
Stack Gas Airflow (dscf/min):	797320	804072	819537	806976	806976
Impinger Catch Solution					
Ammonia Detection Limit (μg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	470	380	350		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (μg):	2.4	1.9	1.8		1.5
Ammonia In Impinger Solution (μg):	25	20	24	23	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.025	0.020	0.024	0.023	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.056	0.048	0.055	0.053	< 0.002
Ammonia Emission Concentration (ppm):	0.080	0.068	0.078	0.075	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2)	0.068	0.056	0.065	0.063	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.082	0.071	0.082	0.078	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.070	0.059	0.068	0.066	< 0.002
Ammonia Emission Rate (lb/hr):	0.169	0.144	0.170	0.161	< 0.001
Ammonia Emission Rate (tons/yr)	0.738	0.633	0.744	0.705	< 0.006

AMTEST
AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: CLR\00-087WD\M4NH$_3$\SUMR1-3
Client: General Electric @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	100% Load Condition HRSG STACK OUTLET				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	6574	6575	6576		
Date:	8/8/00	8/8/00	8/8/00		
M4 Start Time:	0053	0137	0230		
M4 Stop Time:	0123	0207	0300		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	67.63	67.78	68.24	67.88	
Volume Sampled (dscf):	15.074	14.902	15.443	15.140	15.140
Volume Sampled (dscm):	0.427	0.422	0.437	0.429	0.429
Oxygen (percent):	13.8	13.8	13.8	13.8	13.8
Average Observed Barometric Pressure ("Hg):	29.95	29.95	29.95	29.95	29.95
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	65	61	62	63	63
Observed Relative Humidity on Test Day (percent):	67	86	79	77	77
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0092	0.0097	0.0094	0.0094	0.0094
Stack Gas Airflow (dscf/min):	848853	849920	842539	847104	847104
Impinger Catch Solution					
Ammonia Detection Limit (μg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	398	470	350		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (μg):	2.0	2.4	1.8		1.5
Ammonia In Impinger Solution (μg):	33	21	24	26	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.033	0.021	0.024	0.026	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.077	0.050	0.055	0.061	< 0.002
Ammonia Emission Concentration (ppm):	0.109	0.070	0.078	0.086	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.091	0.058	0.064	0.071	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.113	0.074	0.081	0.090	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.094	0.062	0.068	0.074	< 0.002
Ammonia Emission Rate (lb/hr):	0.246	0.158	0.173	0.192	< 0.001
Ammonia Emission Rate (tons/yr)	1.08	0.694	0.759	0.843	< 0.006

2.1 Ammonia Emissions

Three (3) 30-minute Method 4 and ammonia (NH_3) tests were performed during each of the high (100%), 95%, 85% and 75% load conditions at the HRSG stack outlet on August 8-9, 2000. NH_3 injection rates are indicated on the summary tables for each test period. Ammonia emission concentration and emission rate results are summarized on the following computer printouts titled "Summary of Results - Ammonia." Concurrent with each test period, supporting velocity, temperature, and airflow data were used to calculate NH_3 emission rates.

Emission concentrations were calculated in units of milligrams per dry standard cubic meter (mg/dscm), dry parts per million (ppm) uncorrected and corrected to fifteen percent oxygen (@ 15% O_2), and ppm emissions corrected to ISO standard day conditions at 15% O_2 using the ambient temperature, humidity, and barometric pressure data collected during each test period by Am Test personnel. Emission rates were calculated in units of pounds per hour (lb/hr) and tons per year (tons/yr). Tons per year calculations assume 24 hours per day, 365 days per year operation.

It should be noted that NH_3 results designated with a less than "<" notation were undetected at the sample detection limit (DL).

AMTEST
AIR QUALITY, LLC

Overall Summary of Results - NH_3, CO, and NO_x

General Electric
@ Clark Public Utilities River Road Generating Project
Vancouver, Washington

August 8-9, 2000

	HRSG STACK OUTLET				
	100% LOAD	95% LOAD	85% LOAD	75% LOAD	*SWCAA Emission Limits*
Oxygen (O_2) (percent)	13.8	13.9	14.2	14.2	—
Ammonia (NH_3)					
parts per million (ppm)	0.086	0.075	0.053	0.035	—
ppm @ 15% oxygen (O_2)	0.071	0.063	0.047	0.030	*10.0*
pounds per hour (lb/hr)	0.192	0.161	0.105	0.058	*22.9*
tons per year (tons/yr)	0.843	0.705	0.462	0.256	—
Carbon Monoxide (CO)					
parts per million (ppm)	0.03	0.0	0.1	0.1	—
ppm @ 15% oxygen (O_2)	0.03	0.0	0.1	0.1	*6.0*
pounds per hour (lb/hr)	0.124	0.0	0.220	0.277	*20.8*
tons per year (tons/yr)	0.541	0.0	0.962	1.21	—
Nitrogen Oxides (NOx)					
parts per million (ppm)	4.0	4.0	3.9	3.8	—
ppm @ 15% oxygen (O_2)	3.4	3.4	3.4	3.3	*4.0*
ppm @ ISO Std. Day Conditions @ 15% oxygen (O_2)	3.5	3.5	3.7	3.5	
pounds per hour (lb/hr)	24.5	23.1	21.1	17.2	*40.0*
tons per year (tons/yr)	107.2	101.3	92.3	75.4	—
pounds per million BTU (lb/MMBtu)	0.012	0.012	0.013	0.012	

[cln00-087wd\overallsum.xls]

2.0
SUMMARY OF RESULTS

A discussion of the sampling and analysis results for each parameter evaluated during this test program follows. The order of presentation is as follows: Methods 4/NH_3, 10, and 20 test results. Summary tables are included in this section, which present the data for each individual run, along with the average for all three runs at each load condition. An overall summary table with the average concentrations for each type of test at each load performed is included on the following page. Refer to the Table of Contents to locate specific information for each type of test. For each test period, measured airflow data were used to calculate emission rates. The summary tables in Section 2.0 of the report contain information obtained from computer printouts of results for each individual run which are included in Appendix A of this report. Appendix B of this report contains copies of the ammonia laboratory analysis data. Appendix C of this report contains example calculations of the derivation of emission concentration and emission rate results, along with copies of the original field data sheets. Appendix D of this report contains copies of Clark Public Utilities' fuel usage and process data obtained during the testing periods. Appendix E of this report contains miscellaneous supporting information.

Table 1 Overview of Emissions Test Program			
Load Condition	**Parameter**	**Method(s)**	**Time Duration**
100% Load Condition	NO_x	19, 20	(3) 24-minute
	O_2, CO	3A, 10	(3) 24-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
95% Load Condition	NO_x	19, 20	(3) 24-minute
	O_2, CO	3A, 10	(3) 24-miniute
	NH_3	modified M4/ST-1B	(3) 30-minute
85% Load Condition	NO_x	19, 20	(3) 24-minute
	O_2, CO	3A, 10	(3) 24-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
75% Load Condition	NO_x	19, 20	(3) 24-minute
	O_2, CO	3A, 10	(3) 24-minute
	NH_3	modified M4/ST-1B	(3) 30-minute

Mr. K. Steven Mackey and Mr. Gregory L. Lipnickey of Am Test-Air Quality, LLC performed the field sampling and in-field sample recovery and analysis. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, laboratory analysis, data reduction, and quality assurance review. Ms. Christine L. Ramsey and Ms. Judith A. Aasland prepared the report. Ms. Angela F. Hansen and Mr. Kris A. Hansen performed the senior review. Am Test, Inc. in Redmond, Washington analyzed the ammonia samples. Mr. Robert Martin of General Electric Contractual Services coordinated this project, and Mr. Steve Hoch of General Electric provided copies of the process data.

- emission rates using Method 19
- oxygen (O_2) and nitrogen oxides (NO_x) from gas turbines using Method 20

The methodology which was used to collect the emission samples is discussed in the July 1, 1999 edition of the EPA document Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Methods 1, 2, 3A, 4, 9, 10, 19, and 20; and in the Bay Area Air Quality Management District (BAQMD) Manual of Procedures, Volumes 3 and 4, dated December 18, 1985. Methods 1 and 2 were performed to measure the gas velocity and temperature for calculating the volumetric flow rate of the stack gas. Method 3A was performed to determine the molecular weight of the gas based on measurements of the concentration of oxygen (O_2) and carbon dioxide (CO_2) in the stack gas. Method 4 was performed to measure the moisture content of the stack gas. The Method 4 sample train was also modified to collect ammonia as described in the Bay Area Air Quality Management District (AQMD) Source Test Procedure ST-1B. The impingers were charged with 0.1 N sulfuric acid (H_2SO_4) which was analyzed for ammonia using rapid flow analysis (RFA), which is a colorimetric analysis procedure. Method 9 opacity (visible) observations could not be performed because emissions testing was performed at night. Method 10 was performed to quantify emissions of carbon monoxide (CO) using a gas filter correlation non-dispersive infrared (NDIR) analyzer. The standard Method 19 F-factor for natural gas of 8710 dscf/MMBtu was used in the emission rate calculations. Method 20 was performed to quantify emissions of nitrogen oxides (NO_X) using a chemiluminescent analyzer. Methodology cited in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, Sections 60.330 through 60.335 was utilized to calculate ISO standard day conditions at 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure. An overview of the test program is referenced below in Table 1.

1.0
INTRODUCTION

The purpose of this source emission evaluation was to quantify emissions from a General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. General Electric Contractual Services contracted Am Test-Air Quality, LLC based in Preston, Washington to perform this work. This testing was performed to demonstrate compliance with Clark Public Utilities Order of Approval No. 95-1800R1 issued by the Southwest Clean Air Authority (SWCAA).

The River Road Generating Project is a natural gas-fired combined cycle generating facility consisting of one (1) GE Model 7231FA gas turbine which is equipped with a heat recovery steam generator (HRSG). The turbine is identified in this report as the HRSG stack outlet.

The parameters listed below were measured at the HRSG stack outlet. Emissions testing were performed at four (4) different load conditions, identified as the 100% (high), 95%, 85%, and 75% load conditions. Ammonia (NH_3), carbon monoxide (CO), and nitrogen oxides (NO_x) emissions tests were performed at each of the 4 load conditions.

The parameters, which were measured, and the methods used are listed below:

- volumetric flow rate using methods 1 and 2
- molecular weight (O_2, CO_2) using Method 3A
- moisture using Method 4
- ammonia (NH_3) using a modified Method 4 sample train (ST-1B)
- opacity using Method 9
- carbon monoxide (CO) using Method 10

SOURCE EMISSION

EVALUATION

AMTEST
AIR QUALITY, LLC

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September 7, 2000

Prepared For:

GENERAL ELECTRIC
@ CLARK PUBLIC UTILITIES
RIVER ROAD GENERATING PROJECT
GENERAL ELECTRIC FRAME 7231FA
GAS TURBINE COMPLIANCE TEST
VANCOUVER, WASHINGTON
AUGUST 8-9, 2000

Kris A. Hansen, QEP
President

Angela F. Hansen
Vice President

K. Steven Mackey
Sr. Project Engineer

Am Test-Air Quality, LLC
Preston, Washington

We certify that the information contained herein is accurate and complete to the best of our knowledge.

[CLR(jaa)\00-087WD\GE@ClarkM20. 00-087]

AMTEST
AIR QUALITY LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\99-100WD\M4NH$_3$\SUMR10-12
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	100% Load Condition HRSG STACK OUTLET				
	RUN #10	RUN #11	RUN #12	AVERAGE	BLANK
Lab #:	5393	5394	5395		
Date:	8/31/99	8/31/99	8/31/99		
M4 Start Time:	0551	0639	0725		
M4 Stop Time:	0623	0711	0757		
Sample Length (minutes):	32.0	32.0	32.0		
Ammonia Injection Rate (lb/hr):	65.43	66.14	69.14	66.90	
Volume Sampled (dscf):	22.975	22.089	24.051	23.038	23.038
Volume Sampled (dscm):	0.651	0.626	0.681	0.653	0.653
Oxygen (percent):	13.7	13.7	13.7	13.7	13.7
Average Observed Barometric Pressure ("Hg):	30.00	30.00	30.00	30.00	30.00
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	56	58	58	57	57
Observed Relative Humidity on Test Day (percent):	72	77	76	75	75
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0068	0.0081	0.0066	0.0072	0.0072
Stack Gas Airflow (dscf/min):	739420	755840	782439	759233	759233
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	427	382	387		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	2.1	1.9	1.9		1.5
Ammonia In Impinger Solution (µg):	6	5	5	5	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.006	0.005	0.005	0.005	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.009	0.008	0.007	0.008	< 0.002
Ammonia Emission Concentration (ppm):	0.013	0.011	0.010	0.012	< 0.003
Ammonia Emission Concentration (ppm @ 15% O_2):	0.011	0.009	0.008	0.009	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.013	0.012	0.010	0.012	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2)	0.011	0.010	0.009	0.010	< 0.003
Ammonia Emission Rate (lb/hr):	0.026	0.023	0.022	0.023	< 0.002
Ammonia Emission Rate (tons/yr):	0.112	0.099	0.094	0.102	< 0.008

AMTEST
AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\99-100WD\M4NH$_3$\SUMR7-9
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	95% Load Condition HRSG STACK OUTLET				
	RUN #7	RUN #8	RUN #9	AVERAGE	BLANK
Lab #:	5390	5391	5392		
Date:	8/31/99	8/31/99	8/31/99		
M4 Start Time:	0330	0417	0503		
M4 Stop Time:	0402	0449	0535		
Sample Length (minutes):	32.0	32.0	32.0		
Ammonia Injection Rate (lb/hr):	44.76	44.48	45.00	44.75	
Volume Sampled (dscf):	25.739	25.676	23.929	25.115	25.115
Volume Sampled (dscm):	0.729	0.727	0.678	0.711	0.711
Oxygen (percent):	14.1	14.1	14.1	14.1	14.1
Average Observed Barometric Pressure ("Hg):	29.92	29.95	29.95	29.94	29.94
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	69	69	68	69	69
Observed Relative Humidity on Test Day (percent):	57	57	56	57	57
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0068	0.0068	0.0064	0.0067	0.0067
Stack Gas Airflow (dscf/min):	719464	711440	706445	712450	712450
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	400	388	360		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	2.0	1.9	1.8		1.5
Ammonia In Impinger Solution (µg):	7	4	7	6	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.007	0.004	0.007	0.006	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.010	0.006	0.010	0.008	< 0.002
Ammonia Emission Concentration (ppm):	0.014	0.008	0.015	0.012	< 0.003
Ammonia Emission Concentration (ppm @ 15% O_2):	0.012	0.007	0.013	0.010	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.013	0.008	0.014	0.012	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2)	0.012	0.007	0.012	0.010	< 0.003
Ammonia Emission Rate (lb/hr):	0.026	0.015	0.027	0.023	< 0.002
Ammonia Emission Rate (tons/yr):	0.113	0.064	0.120	0.099	< 0.008

AMTEST
AIR QUALITY LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\99-100WD\M4NH$_3$\SUMR4-6
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	85% Load Condition HRSG STACK OUTLET				
	RUN #4	RUN #5	RUN #6	AVERAGE	BLANK
Lab #:	5387	5388	5389		
Date:	8/31/99	8/31/99	8/31/99		
M4 Start Time:	0105	0153	0240		
M4 Stop Time:	0137	0225	0312		
Sample Length (minutes):	32.0	32.0	32.0		
Ammonia Injection Rate (lb/hr):	26.63	31.00	31.53	29.72	
Volume Sampled (dscf):	26.186	24.520	18.875	23.194	23.194
Volume Sampled (dscm):	0.742	0.694	0.535	0.657	0.657
Oxygen (percent):	14.1	14.1	14.1	14.1	14.1
Average Observed Barometric Pressure ("Hg):	29.95	29.95	29.95	29.95	29.95
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	57	57	56	57	57
Observed Relative Humidity on Test Day (percent):	70	70	69	70	70
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0068	0.0068	0.0056	0.0064	0.0064
Stack Gas Airflow (dscf/min):	706244	704705	702985	704645	704645
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	367	425	380		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.8	2.1	1.9		1.5
Ammonia In Impinger Solution (µg):	7	7	5	6	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.007	0.007	0.005	0.006	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.009	0.010	0.009	0.010	< 0.002
Ammonia Emission Concentration (ppm):	0.013	0.014	0.013	0.014	< 0.003
Ammonia Emission Concentration (ppm @ 15% O_2):	0.012	0.012	0.011	0.012	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.014	0.014	0.013	0.014	< 0.003
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.012	0.013	0.011	0.012	< 0.003
Ammonia Emission Rate (lb/hr):	0.025	0.027	0.025	0.025	< 0.002
Ammonia Emission Rate (tons/yr):	0.109	0.117	0.108	0.111	< 0.007

AMTEST
AIR QUALITY LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\99-100WD\M4NH$_3$\SUMR1-3
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	75% Load Condition HRSG STACK OUTLET				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	5384	5385	5386		
Date:	8/30/99	8/30/99	8/30/99		
M4 Start Time:	2240	2328	0015		
M4 Stop Time:	2312	2400	0047		
Sample Length (minutes):	32.0	32.0	32.0		
Ammonia Injection Rate (lb/hr):	15.75	16.09	15.72	15.85	
Volume Sampled (dscf):	28.274	26.935	27.033	27.414	27.414
Volume Sampled (dscm):	0.801	0.763	0.766	0.777	0.777
Oxygen (percent):	14.2	14.1	14.1	14.1	14.1
Average Observed Barometric Pressure ("Hg):	29.90	29.90	29.90	29.90	29.90
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	58	58	58	58	58
Observed Relative Humidity on Test Day (percent):	70	70	70	70	70
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0071	0.0071	0.0071	0.0071	0.0071
Stack Gas Airflow (dscf/min):	658878	658542	654479	657300	657300
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	404	375	370		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	2.0	1.9	1.9		1.5
Ammonia In Impinger Solution (µg):	38	13	10	20	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.038	0.013	0.010	0.020	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.047	0.017	0.013	0.026	< 0.002
Ammonia Emission Concentration (ppm):	0.067	0.024	0.018	0.037	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.059	0.021	0.016	0.032	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.068	0.024	0.019	0.037	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.060	0.021	0.016	0.033	< 0.002
Ammonia Emission Rate (lb/hr):	0.117	0.042	0.032	0.064	< 0.001
Ammonia Emission Rate (tons/yr):	0.513	0.184	0.140	0.279	< 0.006

2.1 Ammonia Emissions

Three (3) 32-minute Method 4 and ammonia (NH_3) tests were performed during each of the 75%, 85%, 95% and high (100%) load conditions at the HRSG stack outlet on August 30-31, 1999. NH_3 injection rates are indicated on the summary tables for each test period. Ammonia emission concentration and emission rate results are summarized on the following computer printouts titled "Summary of Results - Ammonia." Concurrent with each test period, supporting velocity, temperature, and airflow data were used to calculate NH_3 emission rates.

Emission concentrations were calculated in units of milligrams per dry standard cubic meter (mg/dscm), dry parts per million (ppm) uncorrected and corrected to fifteen percent oxygen (@ 15% O_2), and ppm emissions corrected to ISO standard day conditions at 15% O_2 using the ambient temperature, humidity, and barometric pressure data collected during each test period by Am Test personnel. Emission rates were calculated in units of pounds per hour (lb/hr) and tons per year (tons/yr). Tons per year calculations assume 24 hours per day, 365 days per year operation.

It should be noted that NH_3 results designated with a less than "<" notation were undetected at the sample detection limit (DL).

Overall Summary of Results - NH_3, CO, and NO_x

Cogentrix of Vancouver, Inc.
@ Clark Public Utilities River Road Generating Project
Vancouver, Washington

August 30-31, 1999

	HRSG STACK OUTLET				
	75% LOAD	85% LOAD	95% LOAD	100% LOAD	*SWAPCA Emission Limits*
Oxygen (O_2) (percent)	14.1	14.1	14.1	13.7	—
Ammonia (NH_3)					
parts per million (ppm)	0.037	0.014	0.012	0.012	—
ppm @ 15% oxygen (O_2)	0.032	0.012	0.010	0.009	*10.0*
pounds per hour (lb/hr)	0.064	0.025	0.023	0.023	*22.9*
tons per year (tons/yr)	0.279	0.111	0.099	0.102	—
Carbon Monoxide (CO)					
parts per million (ppm)	0.0	0.0	0.0	0.0	—
ppm @ 15% oxygen (O_2)	0.0	0.0	0.0	0.0	*6.0*
pounds per hour (lb/hr)	0.0	0.0	0.0	0.0	*20.8*
tons per year (tons/yr)	0.0	0.0	0.0	0.0	—
Nitrogen Oxides (NOx)					
parts per million (ppm)	4.8	4.3	4.3	4.1	—
ppm @ 15% oxygen (O_2)	4.2	3.7	3.7	3.6	*4.0*
ppm @ ISO Std. Day Conditions @ 15% oxygen (O_2)	4.3	3.7	3.7	3.5	
pounds per hour (lb/hr)	22.6	21.5	21.5	20.9	*40.0*
tons per year (tons/yr)	99.0	94.4	94.4	91.7	—
pounds per million BTU (lb/MMBtu)	0.015	0.014	0.014	0.013	

[aal99-100wd\overallsum.xls]

2.0 SUMMARY OF RESULTS

A discussion of the sampling and analysis results for each parameter evaluated during this test program follows. The order of presentation is as follows: Methods 4/NH_3, 10 and 20 test results. Summary tables are included in this section, which present the data for each individual run, along with the average for all three runs at each load condition. An overall summary table with the average concentrations for each type of test performed is included on the following page. Refer to the Table of Contents to locate specific information for each type of test. For each test period, measured airflow data were used to calculate emission rates. The summary tables in Section 2.0 of the report contain information obtained from computer printouts of results for each individual run which are included in Appendix A of this report. Appendix B of this report contains copies of the ammonia laboratory analysis data. Appendix C of this report contains example calculations of the derivation of emission concentration and emission rate results, along with copies of the original field data sheets. Appendix D of this report contains copies of Clark Public Utilities' fuel usage and process data obtained during the testing periods. Appendix E of this report contains miscellaneous supporting information.

Table 1 Overview of Emissions Test Program			
Load Condition	**Parameter**	**Method(s)**	**Time Duration**
75% Load Condition	NO_X	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 32-minute
85% Load Condition	NO_X	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-miniute
	NH_3	modified M4/ST-1B	(3) 32-minute
95% Load Condition	NO_X	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 32-minute
100% Load Condition	NO_X	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 32-minute

Mr. Stanley B. Moye and. Mr. Aaron C. Porter of Am Test-Air Quality, LLC performed the field sampling and in-field sample recovery and analysis. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, laboratory analysis, data reduction, and quality assurance review. Ms. Judith A. Aasland prepared the report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior review. Am Test, Inc. in Redmond, Washington analyzed the ammonia samples. Mr. Tracy Patterson of Cogentrix of Virginia, Inc. coordinated this project and provided copies of the fuel usage and process data.

- opacity using Method 9
- carbon monoxide (CO) using Method 10
- emission rates using Method 19
- oxygen (O_2) and nitrogen oxides (NO_x) from gas turbines using Method 20

The methodology which was used to collect the emission samples is discussed in the July 1, 1998 edition of the EPA document Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Methods 1, 2, 3A, 4, 9, 10, 19, and 20; and in the Bay Area Air Quality Management District (BAQMD) Manual of Procedures, Volumes 3 and 4, dated December 18, 1985. Methods 1 and 2 were performed to measure the gas velocity and temperature for calculating the volumetric flow rate of the stack gas. Method 3A was performed to determine the molecular weight of the gas based on measurements of the concentration of oxygen (O_2) and carbon dioxide (CO_2) in the stack gas. Method 4 was performed to measure the moisture content of the stack gas. The Method 4 sample train was also modified to collect ammonia as described in the Bay Area Air Quality Management District (AQMD) Source Test Procedure ST-1B. The impingers were charged with 0.1 N sulfuric acid (H_2SO_4) which was analyzed for ammonia using rapid flow analysis (RFA), which is a colorimetric analysis procedure. Several attempts were made on the test days to record Method 9 opacity (visible) emissions, however, due to dark skies; opacity observations could not be performed. Method 10 was performed to quantify emissions of carbon monoxide (CO) using a gas filter correlation non-dispersive infrared (NDIR) analyzer. The standard Method 19 F-factor for natural gas of 8710 dscf/MMBtu was used in the emission rate calculations. Method 20 was performed to quantify emissions of nitrogen oxides (NO_X) using a chemiluminescent analyzer. Methodology cited in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, Sections 60.330 through 60.335 was utilized to calculate ISO standard day conditions at 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure. An overview of the test program is referenced below in Table 1.

1.0 INTRODUCTION

The purpose of this source emission evaluation was to quantify emissions from a General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC based in Preston, Washington to perform these emissions tests. This testing was performed to demonstrate compliance with Clark Public Utilities Order of Approval No. 95-1800R1 issued by the Southwest Air Pollution Control Authority (SWAPCA).

The River Road Generating Project is a natural gas-fired combined cycle generating facility consisting of one (1) GE Model 7231FA gas turbine which is equipped with a heat recovery steam generator (HRSG). The turbine is identified in this report as the HRSG stack outlet.

The parameters listed below were measured at the HRSG stack outlet. Emissions testing were performed at four (4) different load conditions, identified as the 75%, 85%, 95%, and 100% (high) load conditions. Ammonia (NH_3), carbon monoxide (CO), and nitrogen oxides (NO_x) emissions tests were performed at each of the 4 load conditions.

The parameters, which were measured, and the methods used are listed below:

- volumetric flow rate using methods 1 and 2
- molecular weight (O_2, CO_2) using Method 3A
- moisture using Method 4
- ammonia (NH_3) using a modified Method 4 sample train (ST-1B)

SOURCE EMISSION

EVALUATION

AMTEST
AIR QUALITY, LLC

AmTest-Air Quality, LLC
30545 S.E. 84th St., #5
Preston, WA 98050
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(425)

September 30, 1999

Prepared For:

COGENTRIX OF VANCOUVER, INC.
@ CLARK PUBLIC UTILITIES
RIVER ROAD GENERATING PROJECT
GENERAL ELECTRIC FRAME 7231FA
GAS TURBINE COMPLIANCE TEST
VANCOUVER, WASHINGTON
AUGUST 30-31, 1999

Kris A. Hansen, QEP
President

Angela F. Blaisdell
Vice President

Stanley B. Moye
Sr. Air Quality Specialist

Am Test-Air Quality, LLC
Preston, Washington

We certify that the information contained herein is accurate and complete to the best of our knowledge.

[GW3\jaa\c\winword\report99\CogentrixM20899, #99-100]

AMTEST
AIR QUALITY LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-114WD\M4NH_3\SUMR1-3
Client: Cogentrix of Vancouver, Inc.
Location Vancouver, WA

	High (100%) Load Condition HRSG STACK OUTLET				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	4223	4224	4225		
Date:	9/3/98	9/3/98	9/3/98		
M4 Start Time:	1116	1208	1255		
M4 Stop Time:	1146	1238	1325		
Sample Length (minutes):	30.0	30.0	30.0		
Volume Sampled (dscf):	22.632	22.790	22.733	22.718	22.718
Volume Sampled (dscm):	0.641	0.645	0.644	0.643	0.643
Oxygen (percent):	13.7	13.9	13.9	13.8	13.8
Ammonia Injection Rate (lb/hr):	39.61	36.97	35.53	37.37	
Average Observed Barometric Pressure ("Hg):	30.00	30.00	30.00	30.00	30.00
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	79	82	83	81	81
Observed Relative Humidity on Test Day (percent):	48	50	45	48	48
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0106	0.0118	0.0109	0.0111	0.0111
Stack Gas Airflow* (dscf/min):	770904	783414	783377	779232	779232
Impinger Catch Solution					
Ammonia Detection Limit (μg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	310	300	305		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (μg):	1.6	1.5	1.5		1.5
Ammonia In Impinger Solution (μg):	8.1	6.0	5.5	6.5	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.008	0.006	0.006	0.007	< 0.0015
Ammonia Emission Concentration (mg/dscm):	0.013	0.009	0.009	0.010	< 0.0001
Ammonia Emission Concentration (ppm):	0.018	0.013	0.012	0.014	< 0.0002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.015	0.011	0.010	0.012	< 0.0001
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.018	0.014	0.012	0.015	< 0.0002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.015	0.011	0.010	0.012	< 0.0001
Ammonia Emission Rate (lb/hr):	0.036	0.027	0.025	0.030	< 0.0001
Ammonia Emission Rate (tons/yr):	0.160	0.120	0.110	0.130	< 0.0004

*Obtained from concurrent Method 1 and 2 tests.

2.1 Ammonia Emissions

Three (3) 30-minute Method 4 and ammonia (NH_3) tests were performed at the high (100%) load condition at the HRSG stack outlet on September 3, 1998. NH_3 injection rates are indicated on the summary tables for each test period. Ammonia emission concentration and emission rate results are summarized on the following computer printout titled "Summary of Results - Ammonia." Supporting velocity, temperature, and airflow data collected during each test period were used to calculate emission rates.

Emission concentrations were calculated in units of milligrams per dry standard cubic meter (mg/dscm), dry parts per million (ppm) uncorrected and corrected to fifteen percent oxygen (@ 15% O_2), and ppm emissions corrected to ISO standard day conditions at 15% O_2 using the ambient temperature, humidity, and barometric pressure data collected during each test period by Am Test personnel. Emission rates were calculated in units of pounds per hour (lb/hr) and tons per year (tons/yr). Tons per year calculations assume 24 hours per day, 365 days per year operation.

It should be noted that NH_3 results designated with a less than "<" notation were undetected at the sample detection limit (DL).

AMTEST
AIR QUALITY, LLC

Overall Summary of Results - NH_3, Opacity, CO, and NO_x

Cogentrix of Vancouver, Inc.
@ Clark Public Utilities River Road Generating Project
Vancouver, Washington

September 3, 1998

	HRSG STACK OUTLET	
	100% LOAD	***SWAPCA Emission Limits***
Oxygen (O_2) (percent)	13.8	—
Ammonia (NH_3)		
parts per million (ppm)	0.014	—
ppm @ 15% oxygen (O_2)	0.012	*10.0*
pounds per hour (lb/hr)	0.030	*22.9*
tons per year (tons/yr)	0.130	—
Opacity (Visible Emissions)		
percent	0	*5*
Carbon Monoxide (CO)		
parts per million (ppm)	2.8	—
ppm @ 15% oxygen (O_2)	2.4	*6.0*
pounds per hour (lb/hr)	9.57	*20.8*
tons per year (tons/yr)	41.9	—
Nitrogen Oxides (NOx)		
parts per million (ppm)	3.9	—
ppm @ 15% oxygen (O_2)	3.3	*4.0*
ppm @ ISO Std. Day Conditions @ 15% oxygen (O_2)	3.3	
pounds per hour (lb/hr)	21.8	*40.0*
tons per year (tons/yr)	95.4	—
pounds per million BTU (lb/MMBtu)	0.012	

2.0
SUMMARY OF RESULTS

A discussion of the sampling and analysis results for each parameter evaluated during this test program follows. The order of presentation is as follows: Method 4/NH_3, 9, 10, and 20 test results. Summary tables are included in this section which present the data for each individual run, along with the average for all three runs. An overall summary table with the average concentrations for each type of test performed is included on the following page. Refer to the Table of Contents to locate specific information for each type of test. For each test period, measured airflow data were used to calculate emission rates. The summary tables in Section 2.0 of the report contain information obtained from computer printouts of results for each individual run which are included in Appendix A of this report. Appendix B of this report contains copies of the ammonia laboratory analysis data. Appendix C of this report contains example calculations of the derivation of emission concentration and emission rate results, along with copies of the original field data sheets. Appendix D of this report contains copies of Clark Public Utilities' fuel usage and process data obtained during the testing periods. Appendix E of this report contains miscellaneous supporting information.

Table 1. Overview of Emissions Test Program

Load Condition	Parameter	Method(s)	Time Duration
High (100%) Load Condition	NO_x	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	1, 2, M4/ST-1B	(3) 30-minute
	opacity	9	(1) 6-minute

Mr. Paul J. Clark and Mr. Ryan D. Radonski of Am Test-Air Quality, LLC performed the field sampling and in-field sample recovery. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, laboratory analysis, data reduction, and quality assurance review. Ms. Judith A. Aasland prepared the report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior review. Am Test, Inc. in Redmond, Washington analyzed the ammonia samples. Mr. Tracy Patterson of Cogentrix of Virginia, Inc. coordinated this project and provided copies of the fuel usage and process data.

The methodology which was used to collect the emission samples is discussed in the July 1, 1997 edition of the EPA document Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Methods 1, 2, 3A, 4, 9, 10, 19, and 20; and in the Bay Area Air Quality Management District (BAQMD) Manual of Procedures, Volumes 3 and 4, dated December 18, 1985. Methods 1 and 2 were performed to measure the gas velocity and temperature for calculating the volumetric flow rate. Method 3A was performed to determine the molecular weight of the gas based on measurements of the concentration of oxygen (O_2) and carbon dioxide (CO_2) in the stack gas. Method 4 was performed to measure the moisture content of the stack gas. The Method 4 sample train was also modified to collect ammonia as described in the Bay Area Air Quality Management District (AQMD) Source Test Procedure ST-1B. The impingers were charged with 0.1 N hydrochloric acid (HCl) which was analyzed for ammonia using rapid flow analysis (RFA), which is a colorimetric analysis procedure. Method 9 opacity (visible) emissions observations were performed. Method 10 was performed to quantify emissions of carbon monoxide (CO) using a gas filter correlation non-dispersive infrared (NDIR) analyzer. The standard Method 19 F-factor for natural gas of 8710 dscf/MMBtu was used in the emission rate calculations. Method 20 was performed to quantify emissions of nitrogen oxides (NO_x) using a chemiluminescent analyzer. Methodology cited in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, Sections 60.330 through 60.335 was utilized to calculate ISO standard day conditions at 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure. An overview of the test program is referenced below in Table 1.

1.0 INTRODUCTION

The purpose of this source emission evaluation was to quantify emissions from a General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC based in Preston, Washington to perform these emissions tests. This testing was performed to demonstrate compliance with Clark Public Utilities Order of Approval No. 95-1800R1 issued by the Southwest Air Pollution Control Authority (SWAPCA).

The River Road Generating Project is a natural gas-fired combined cycle generating facility consisting of one (1) GE Model 7231FA gas turbine which is equipped with a heat recovery steam generator (HRSG). The turbine is identified in this report as the HRSG stack outlet.

The parameters listed below were measured at the HRSG stack outlet. Emissions testing was performed at the 100% (high) load condition. Ammonia (NH_3), carbon monoxide (CO), and nitrogen oxides (NO_x) emissions tests were performed at the 100% (high) load condition.

- gas temperature and velocity using Methods 1 and 2
- molecular weight (O_2, CO_2) using Method 3A
- moisture using Method 4
- ammonia (NH_3) using a modified Method 4 sample train (ST-1B)
- opacity using Method 9
- carbon monoxide (CO) using Method 10
- theoretical airflow and emission rates using Method 19
- oxygen (O_2) and nitrogen oxides (NO_x) from gas turbines using Method 20

SOURCE EMISSION

EVALUATION

AMTEST
AIR QUALITY LLC

AmTest-Air Quality, LLC
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October 6, 1998

Prepared For:

COGENTRIX OF VANCOUVER, INC.
@ CLARK PUBLIC UTILITIES
RIVER ROAD GENERATING PROJECT
GENERAL ELECTRIC FRAME 7231FA
GAS TURBINE
HIGH LOAD CONDITION RETEST
VANCOUVER, WASHINGTON
SEPTEMBER 3, 1998

Kris A. Hansen, QEP
President

Angela F. Blaisdell
Vice President

Paul J. Clark
Air Quality Specialist II

Am Test-Air Quality, LLC
Preston, Washington

We certify that the information contained herein is accurate and complete to the best of our knowledge.

[GW3\jaa\c\winword\report98\cogentrixM20. #98-088]

AMTEST AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-088WD\M4NH3\SUMR10-12
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	100% Load Condition HRSG STACK OUTLET				
	RUN #10	RUN #11	RUN #12	AVERAGE	BLANK
Lab #:	4050	4051	4052		
Date:	7/16/98	7/16/98	7/16/98		
M4 Start Time:	1315	1403	1450		
M4 Stop Time:	1345	1433	1520		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	10.77	18.72	16.71	15.40	
Volume Sampled (dscf):	21.591	21.760	21.572	21.641	21.641
Volume Sampled (dscm):	0.611	0.616	0.611	0.613	0.613
Oxygen (percent):	13.8	13.9	13.9	13.9	13.9
Average Observed Barometric Pressure ("Hg):	30.10	30.10	30.10	30.10	30.10
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	86	89	95	90	90
Observed Relative Humidity on Test Day (percent):	48	47	42	46	46
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0132	0.0143	0.0149	0.0141	0.0141
Method 19 Theoretical Stack Gas Airflow (dscf/min):	677296	683849	681229	680791	680791
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	300	290	290		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.5	1.4	1.4		1.5
Ammonia In Impinger Solution (µg):	< 1.5	< 1.4	< 1.4	< 1.4	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	< 0.002	< 0.001	< 0.001	< 0.001	< 0.001
Ammonia Emission Concentration (mg/dscm):	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002
Ammonia Emission Concentration (ppm):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	< 0.004	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Rate (lb/hr):	< 0.006	< 0.006	< 0.006	< 0.006	< 0.0002
Ammonia Emission Rate (tons/yr):	< 0.027	< 0.026	< 0.026	< 0.026	< 0.001

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SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-088WD\M4NH3\SUMR7-9
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	95% Load Condition HRSG STACK OUTLET				
	RUN #7	RUN #8	RUN #9	AVERAGE	BLANK
Lab #:	4047	4048	4049		
Date:	7/16/98	7/16/98	7/16/98		
M4 Start Time:	1049	1137	1228		
M4 Stop Time:	1119	1207	1258		
Sample Length (minutes):	30.0	30.0	30.0		
Ammonia Injection Rate (lb/hr):	12.05	13.43	14.30	13.26	
Volume Sampled (dscf):	21.604	21.679	21.987	21.757	21.757
Volume Sampled (dscm):	0.612	0.614	0.623	0.616	0.616
Oxygen (percent):	13.8	13.8	13.8	13.8	13.8
Average Observed Barometric Pressure ("Hg):	30.10	30.10	30.10	30.10	30.10
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92	29.92	29.92	29.92
Average Ambient Temperature (°F):	81	82	86	83	83
Observed Relative Humidity on Test Day (percent):	60	54	50	55	55
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0138	0.0127	0.0135	0.0133	0.0133
Method 19 Theoretical Stack Gas Airflow (dscf/min):	684846	683356	680873	683025	683025
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	280	310	295		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.4	1.6	1.5		1.5
Ammonia In Impinger Solution (µg):	< 1.4	< 1.6	< 1.5	< 1.5	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	< 0.001	< 0.002	< 0.002	< 0.002	< 0.001
Ammonia Emission Concentration (mg/dscm):	< 0.002	< 0.003	< 0.002	< 0.002	< 0.002
Ammonia Emission Concentration (ppm):	< 0.003	< 0.004	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	< 0.003	< 0.004	< 0.004	< 0.004	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Rate (lb/hr):	< 0.006	< 0.007	< 0.006	< 0.006	< 0.0002
Ammonia Emission Rate (tons/yr):	< 0.026	< 0.029	< 0.027	< 0.027	< 0.001

AMTEST AIR QUALITY, LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-088WD\M4NH$_3$\SUMR4-6
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	85% Load Condition HRSG STACK OUTLET								
		RUN #4		RUN #5		RUN #6		AVERAGE	BLANK
Lab #:		4044		4045		4046			
Date:		7/16/98		7/16/98		7/16/98			
M4 Start Time:		0744		0938		0925			
M4 Stop Time:		0814		1008		0955			
Sample Length (minutes):		30.0		30.0		30.0			
Ammonia Injection Rate (lb/hr):		0.0		0.0		0.0		0.0	
Volume Sampled (dscf):		22.172		22.183		22.840		22.398	22.398
Volume Sampled (dscm):		0.628		0.628		0.647		0.634	0.634
Oxygen (percent):		14.2		14.1		14.2		14.2	14.2
Average Observed Barometric Pressure ("Hg):		30.12		30.12		30.12		30.12	30.12
Reference Inlet Absolute Pressure ("Hg):		29.92		29.92		29.92		29.92	29.92
Average Ambient Temperature (°F):		66		73		76		72	72
Observed Relative Humidity on Test Day (percent):		95		73		74		81	81
Observed Humidity of Ambient Air (g H_2O/g Air):		0.0135		0.0127		0.0144		0.0135	0.0135
Method 19 Theoretical Stack Gas Airflow (dscf/min):		672466		662473		673624		669521	669521
Impinger Catch Solution									
Ammonia Detection Limit (μg/ml):		0.005		0.005		0.005			0.005
Liquid Volume of Sample (ml):		290		300		290			300
Dilution Factor:		1		1		1			1
Ammonia Detection Limit (μg):		1.4		1.5		1.4			1.5
Ammonia In Impinger Solution (μg):	<	1.4	<	1.5	<	1.4	<	1.4	< 1.5
Ammonia (NH_3) Emissions									
Ammonia Concentration in Sample (mg):	<	0.001	<	0.002	<	0.001	<	0.001	< 0.001
Ammonia Emission Concentration (mg/dscm):	<	0.002	<	0.002	<	0.002	<	0.002	< 0.002
Ammonia Emission Concentration (ppm):	<	0.003	<	0.003	<	0.003	<	0.003	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	<	0.003	<	0.003	<	0.003	<	0.003	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	<	0.004	<	0.004	<	0.003	<	0.004	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	<	0.003	<	0.003	<	0.003	<	0.003	< 0.002
Ammonia Emission Rate (lb/hr):	<	0.006	<	0.006	<	0.005	<	0.006	< 0.0002
Ammonia Emission Rate (tons/yr):	<	0.025	<	0.026	<	0.024	<	0.025	< 0.001

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SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-088WD\M4NH3\SUMR1-3
Client: Cogentrix Of Vancouver, Inc. @ Clark Public Utilities
Location: River Road Generating Project
Vancouver, Washington

	75% Load Condition HRSG STACK OUTLET						
	RUN #1	RUN #2		RUN #3		AVERAGE	BLANK
Lab #:	4041	4042		4043			
Date:	7/15/98	7/15/98		7/15/98			
M4 Start Time:	1651	1740		1830			
M4 Stop Time:	1721	1810		1900			
Sample Length (minutes):	30.0	30.0		30.0			
Ammonia Injection Rate (lb/hr):	0.0	0.0		0.0		0.0	
Volume Sampled (dscf):	22.584	22.256		23.545		22.795	22.795
Volume Sampled (dscm):	0.640	0.630		0.667		0.646	0.646
Oxygen (percent):	14.2	14.2		14.2		14.2	14.2
Average Observed Barometric Pressure ("Hg):	30.15	30.15		30.15		30.15	30.15
Reference Inlet Absolute Pressure ("Hg):	29.92	29.92		29.92		29.92	29.92
Average Ambient Temperature (°F):	83	83		82		83	83
Observed Relative Humidity on Test Day (percent):	48	48		52		49	49
Observed Humidity of Ambient Air (g H_2O/g Air):	0.0120	0.0120		0.0123		0.0121	0.0121
Method 19 Theoretical Stack Gas Airflow (dscf/min):	600882	600987		601619		601163	601163
Impinger Catch Solution							
Ammonia Detection Limit (µg/ml):	0.005	0.005		0.005			0.005
Liquid Volume of Sample (ml):	275	310		290			290
Dilution Factor:	1	1		1			1
Ammonia Detection Limit (µg):	1.4	1.6		1.4			1.5
Ammonia In Impinger Solution (µg):	8.8	3.7	<	1.4	~	4.6	< 1.5
Ammonia (NH_3) Emissions							
Ammonia Concentration in Sample (mg):	0.009	0.004	<	0.001	~	0.004	< 0.001
Ammonia Emission Concentration (mg/dscm):	0.014	0.006	<	0.002	~	0.007	< 0.002
Ammonia Emission Concentration (ppm):	0.019	0.008	<	0.003	~	0.009	< 0.002
Ammonia Emission Concentration (ppm @ 15% O_2):	0.017	0.007	<	0.003	~	0.008	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond.):	0.020	0.009	<	0.003	~	0.010	< 0.002
Ammonia Emission Concentration (ppm @ ISO Cond. @ 15% O_2):	0.018	0.008	<	0.003	~	0.008	< 0.002
Ammonia Emission Rate (lb/hr):	0.031	0.013	<	0.005	~	0.015	< 0.0002
Ammonia Emission Rate (tons/yr):	0.136	0.058	<	0.021	~	0.064	< 0.001

2.1 Ammonia Emissions

Three (3) 30-minute Method 4 and ammonia (NH_3) tests were performed during each of the 75%, 85%, 95%, and high (100%) load conditions at the HRSG stack outlet on July 15-16, 1998. NH_3 injection rates are indicated on the summary tables for each test period. Ammonia emission concentration and emission rate results are summarized on the following computer printouts titled "Summary of Results - Ammonia." Concurrent with each test period, fuel usage data were collected and used to calculate theoretical stack gas airflow data which were used to calculate NH_3 emission rates.

Emission concentrations were calculated in units of milligrams per dry standard cubic meter (mg/dscm), dry parts per million (ppm) uncorrected and corrected to fifteen percent oxygen (@ 15% O_2), and ppm emissions corrected to ISO standard day conditions at 15% O_2 using the ambient temperature, humidity, and barometric pressure data collected during each test period by Am Test personnel. Emission rates were calculated in units of pounds per hour (lb/hr) and tons per year (tons/yr). Tons per year calculations assume 24 hours per day, 365 days per year operation.

It should be noted that NH_3 results designated with a less than "<" notation were undetected at the sample detection limit (DL). When the NH_3 results for two (2) or more runs are averaged together, if a value is less than (<) the DL, it is counted as zero (0) in the average. If 1 or 2 values are < the DL and the average value is greater than (>) the DL, then the average is presented as an approximation (~). If the average value is < the average DL, then the average DL is designated with a "<."

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Overall Summary of Results - NH_3, Opacity, CO, and NO_x

Cogentrix of Vancouver, Inc.
@ Clark Public Utilities River Road Generating Project
Vancouver, Washington

July 15-16, 1998

	HRSG STACK OUTLET				
	75% LOAD	85% LOAD	95% LOAD	100% LOAD	*SWAPCA Emission Limits*
Oxygen (O_2) (percent)	14.2	14.2	13.8	13.9	—
Ammonia (NH_3)					
parts per million (ppm)	~0.009	< 0.003	< 0.003	< 0.003	—
ppm @ 15% oxygen (O_2)	~0.008	< 0.003	< 0.003	< 0.003	*10.0*
pounds per hour (lb/hr)	~0.015	< 0.006	< 0.006	< 0.006	*22.9*
tons per year (tons/yr)	~0.064	< 0.025	< 0.027	< 0.026	—
Opacity (Visible Emissions)					
percent	0	0	0	0	*5*
Carbon Monoxide (CO)					
parts per million (ppm)	0.0	0.0	0.0	0.0	—
ppm @ 15% oxygen (O_2)	0.0	0.0	0.0	0.0	*6.0*
pounds per hour (lb/hr)	0.0	0.0	0.0	0.0	*20.8*
tons per year (tons/yr)	0.0	0.0	0.0	0.0	—
Nitrogen Oxides (NOx)					
parts per million (ppm)	4.1	4.3	3.8	4.0	—
ppm @ 15% oxygen (O_2)	3.6	3.8	3.2	3.4	*4.0*
ppm @ ISO Std. Day Conditions @ 15% oxygen (O_2)	3.7	4.1	3.4	3.5	
pounds per hour (lb/hr)	17.5	20.6	18.6	19.5	*40.0*
tons per year (tons/yr)	76.7	90.3	81.4	85.4	—
pounds per million BTU (lb/MMBtu)	0.013	0.014	0.012	0.012	

[jaat98-068wd\overallsum xls]

2.0 SUMMARY OF RESULTS

A discussion of the sampling and analysis results for each parameter evaluated during this test program follows. The order of presentation is as follows: Method 4/NH_3, 9, 10, and 20 test results. Summary tables are included in this section which present the data for each individual run, along with the average for all three runs at each load condition. An overall summary table with the average concentrations for each type of test performed is included on the following page. Refer to the Table of Contents to locate specific information for each type of test. For each test period, theoretical airflow data were used to calculate emission rates. The summary tables in Section 2.0 of the report contain information obtained from computer printouts of results for each individual run which are included in Appendix A of this report. Appendix B of this report contains copies of the ammonia laboratory analysis data. Appendix C of this report contains example calculations of the derivation of emission concentration and emission rate results, along with copies of the original field data sheets. Appendix D of this report contains copies of Clark Public Utilities' fuel usage and process data obtained during the testing periods. Appendix E of this report contains miscellaneous supporting information.

relative humidity and 101.3 kilopascals pressure. An overview of the test program is referenced below in Table 1.

Table 1. Overview of Emissions Test Program

Load Condition	Parameter	Method(s)	Time Duration
75% Load Condition	NO_x	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
	opacity	9	(1) 6-minute
85% Load Condition	NO_x	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
	opacity	9	(1) 6-minute
95% Load Condition	NO_x	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
	opacity	9	(1) 6-minute
High (100%) Load Condition	NO_x	19, 20	(3) 32-minute
	O_2, CO	3A, 10	(3) 32-minute
	NH_3	modified M4/ST-1B	(3) 30-minute
	opacity	9	(1) 6-minute

Mr. Paul J. Clark and Mr. Aaron C. Porter of Am Test-Air Quality, LLC performed the field sampling and in-field sample recovery and analysis. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, laboratory analysis, data reduction, and quality assurance review. Ms. Judith A. Aasland prepared the report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior review. Am Test, Inc. in Redmond, Washington analyzed the ammonia samples. Mr. Tracy Patterson of Cogentrix of Virginia, Inc. coordinated this project and provided copies of the fuel usage and process data.

The parameters which were measured and the methods used are listed below:

- molecular weight (O_2, CO_2) using Method 3A
- moisture using Method 4
- ammonia (NH_3) using a modified Method 4 sample train (ST-1B)
- opacity using Method 9
- carbon monoxide (CO) using Method 10
- theoretical airflow and emission rates using Method 19
- oxygen (O_2) and nitrogen oxides (NO_x) from gas turbines using Method 20

The methodology which was used to collect the emission samples is discussed in the July 1, 1997 edition of the EPA document Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Methods 3A, 4, 9, 10, 19, and 20; and in the Bay Area Air Quality Management District (BAQMD) Manual of Procedures, Volumes 3 and 4, dated December 18, 1985. Method 3A was performed to determine the molecular weight of the gas based on measurements of the concentration of oxygen (O_2) and carbon dioxide (CO_2) in the stack gas. Method 4 was performed to measure the moisture content of the stack gas. The Method 4 sample train was also modified to collect ammonia as described in the Bay Area Air Quality Management District (AQMD) Source Test Procedure ST-1B. The impingers were charged with 0.1 N sulfuric acid (H_2SO_4) which was analyzed for ammonia using rapid flow analysis (RFA), which is a colorimetric analysis procedure. During each of the four (4) operating loads, Method 9 opacity (visible) emissions were performed. Method 10 was performed to quantify emissions of carbon monoxide (CO) using a gas filter correlation non-dispersive infrared (NDIR) analyzer. Equations referenced in Method 19 were used to calculate theoretical airflow data for each test period, and the standard Method 19 F-factor for natural gas of 8710 dscf/MMBtu was used in the emission rate calculations. Method 20 was performed to quantify emissions of nitrogen oxides (NO_x) using a chemiluminescent analyzer. Methodology cited in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, Sections 60.330 through 60.335 was utilized to calculate ISO standard day conditions at 288 degrees Kelvin, 60 percent

1.0 INTRODUCTION

The purpose of this source emission evaluation was to quantify emissions from a General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC based in Preston, Washington to perform these emissions tests. This testing was performed to demonstrate compliance with Clark Public Utilities Order of Approval No. 95-1800R1 issued by the Southwest Air Pollution Control Authority (SWAPCA).

The River Road Generating Project is a natural gas-fired combined cycle generating facility consisting of one (1) GE Model 7231FA gas turbine which is equipped with a heat recovery steam generator (HRSG). The turbine is identified in this report as the HRSG stack outlet.

The parameters listed below were measured at the HRSG stack outlet. Emissions testing was performed at four (4) different load conditions, identified as the 75%, 85%, 95%, and 100% (high) load conditions. Ammonia (NH_3), carbon monoxide (CO), and nitrogen oxides (NO_x) emissions tests were performed at each of the four (4) load conditions. During each test period, average fuel usage data were used to calculate the theoretical stack gas airflow data.

SOURCE EMISSION

EVALUATION

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August 18, 1998

Prepared For:

COGENTRIX OF VANCOUVER, INC.
@ CLARK PUBLIC UTILITIES
RIVER ROAD GENERATING PROJECT
GENERAL ELECTRIC FRAME 7231FA
GAS TURBINE
VANCOUVER, WASHINGTON
JULY 15-16, 1998

Kris A. Hansen, QEP
President

Angela F. Blaisdell
Vice President

Paul J. Clark
Air Quality Specialist II

Am Test-Air Quality, LLC
Preston, Washington

We certify that the information contained herein is accurate and complete to the best of our knowledge.

[GW3\jaa\c\winword\report98\cogentrixM20, #98-088]

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SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: EMD\98-052WD\M4\NH3SUM
Client: Cogentrix of Vancouver
@ River Road Generating Project
Location: Vancouver, Washington

	GENERAL ELECTRIC MODEL 7231FA GAS TURBINE				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	2840	2841	2842		
Date:	4/20/98	4/20/98	4/20/98		
Start Time:	1100	1138	1214		
Stop Time:	1130	1208	1244		
Sample Length (minutes):	30.0	30.0	30.0		
Volume Sampled:	25.418	25.605	23.987	25.003	
Standard Volume (dscf):	25.265	25.176	23.452	24.631	24.631
Standard Volume (dscm):	0.716	0.713	0.664	0.698	0.698
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	380	372	370		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.9	1.9	1.9		1.5
Ammonia In Impinger Solution (µg):	< 2	< 2	< 2	2	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002
Ammonia Emission Concentration (mg/dscm):	< 0.003	< 0.003	< 0.003	< 0.003	< 0.002
Ammonia Emission Concentration (ppm):	< 0.004	< 0.004	< 0.004	< 0.004@ 15%	< 0.003

0.002 @ 15% O2

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the highest vacuum rate (or greater) used during the test preceded and followed each run.

The impinger catch solutions were submitted to Am Test, Inc.'s Water Chemistry laboratory for NH_3 analysis using rapid flow analysis (RFA), which is a colorimetric analysis procedure. The laboratory analysis data were reported in units of micrograms (µg) per sample. Total NH_3 laboratory analysis results were converted to emission concentration units of milligrams per dry standard cubic meter (mg/dscm) and parts per million (ppm).

Mr. Stanley B. Moye and Mr. David A. Newman of Am Test-Air Quality, LLC performed the field sampling. Am Test, Inc. of Redmond, Washington performed the ammonia analysis of the Method 4/NH_3 samples. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, data reduction, and quality assurance review. Ms. Elizabeth M. Derrick prepared the final report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior report review. Mr. Tracy Patterson of Congentrix of Virginia, Inc. in Prince George, Virginia coordinated this test program.

Please find enclosed three (3) copies of this letter and the data package which includes summary tables of results, separate computer printouts for each run, example calculations of results and field data sheets. Please call Am Test-Air Quality, LLC at (425) 222-7746 if you have any questions or require further information.

Sincerely,
Am Test-Air Quality, LLC

Kris A. Hansen
Kris A. Hansen, QEP
President

Enclosures
[gwl\emd\c:\winword\ltrrpt98\cogentrx498nh3.doc, #98-052]

RECEIVED MAY 26 1998

AMTEST
AIR QUALITY, LLC

AmTest-Air Quality, LLC
30545 S.E. 84th St., #5
Preston, WA 98050
Office: (206) 222-7746
FAX: (206) 222-7849

May 13, 1998

Mr. Tracy Patterson
Cogentrix Energy, Inc.
4453 Crossings Blvd.
Prince George, Virginia 23875

Dear Tracy:

Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC to quantify ammonia (NH_3) emissions at the outlet of the General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Three (3) 30-minute ammonia emission tests were performed at the gas turbine stack on April 20, 1998. Average emissions test results are summarized on the following computer printout titled "Summary of Results - Ammonia."

The methodology which was used to collect the emission samples is discussed in the July 1, 1996 edition of the Environmental Protection Agency (EPA) document EPA Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Method 4, and in the Bay Area Air Quality Management District (BAAQMD) Source Test Procedure ST-1B. The sample train is illustrated in the figure titled "EPA Method 4 Sample Train" which is attached. The Method 4 sample train was modified to collect ammonia (NH_3) using the BAAQMD source test procedure ST-1B. A pump was used to pull the stack gas through a heated probe liner into an impinger train which was immersed in an ice water bath. The first and second impingers were modified Greenburg-Smith type impingers each containing 100 milliliters of 0.1 N hydrochloric acid (HCl) to absorb ammonia. The third impinger was empty, and the fourth bubbler contained indicating silica gel desiccant to absorb any moisture from the stack gas before it entered the control box. The impinger section was maintained at a temperature below 45° F by keeping the train in an ice-water bath. The temperature at the outlet of the silica gel bubbler was monitored to verify that it did not exceed 45° F. Prior to each run, the sample train was leak-checked following the procedures in Method 5. Upon completion of each test, the probe was removed from the stack and a post-test leak check was performed. An acceptable leak check of less than 0.02 cfm at

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SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\98-012WD\M4\NH3SUM
Client: Cogentrix of Vancouver
@ Clark Public Utilities
Location River Road Generating Project
Vancouver, Washington

	GENERAL ELECTRIC MODEL 7231FA GAS TURBINE				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	2573	2574	2575		
Date:	1/19/98	1/19/98	1/19/98		
Start Time:	1315	1355	1435		
Stop Time:	1345	1425	1505		
Sample Length (minutes):	30.0	30.0	30.0		
Standard Sampled (dscf):	21.725	22.465	22.319	22.170	22.170
Standard Sampled (dscm):	0.615	0.636	0.632	0.628	0.628
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	323	330	337		200
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.6	1.7	1.7		1.0
Ammonia In Impinger Solution (µg):	269	134	189	197	2.4
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.269	0.134	0.189	0.197	0.002
Ammonia Emission Concentration (mg/dscm):	0.437	0.211	0.299	0.316	0.004
Ammonia Emission Concentration (ppm):	0.618	0.298	0.422	0.446	0.005

0.55 @ 15% O2
limit = 10 ppm @ 15% O2 (avg)

AMTEST
AIR QUALITY

verify that it did not exceed 45° F. Prior to each run, the sample train was leak-checked following the procedures in Method 5. Upon completion of each test, the probe was removed from the stack and a post-test leak check was performed.

The impinger catch solutions were submitted to Am Test, Inc.'s Water Chemistry laboratory for NH_3 analysis using rapid flow analysis (RFA), which is a colorimetric analysis procedure. The laboratory analysis data were reported in units of micrograms (μg) per sample. Total NH_3 laboratory analysis results were converted to emission concentration units of milligrams per dry standard cubic meter (mg/dscm) and parts per million (ppm). An acceptable leak check of less than 0.02 cfm at the highest vacuum rate (or greater) used during the test preceded and followed each run.

Mr. Kevin P. Orton and Mr. Aaron C. Porter of Am Test-Air Quality, LLC performed the field sampling. Am Test, Inc. of Redmond, Washington performed the ammonia analysis of the Method 4/NH_3 samples. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, data reduction, and quality assurance review. Ms. Elizabeth M. Derrick prepared the final report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior report review. Mr. Tracy Patterson of Congentrix of Virginia, Inc. in Prince George, Virginia coordinated this test program.

Please find enclosed three (3) copies of this letter and the data package which includes summary tables of results, separate computer printouts for each run, example calculations of results and field data sheets. Please call Am Test-Air Quality, LLC at (425) 222-7746 if you have any questions or require further information.

Sincerely,
Am Test-Air Quality, LLC

Kris A. Hansen

Kris A. Hansen, QEP
President

Enclosures
{gw3\cmd\c:\winword\ltrrpt98\cogentrxnh3.doc; #98-012}

AMTEST
AIR QUALITY, LLC

AmTest-Air Quality, LLC
30545 S.E. 84th St., #5
Preston, WA 98050
Office: (206) 222-7746
FAX: (206) 222-7849

February 18, 1998

Mr. Tracy Patterson
Cogentrix Energy, Inc.
4453 Crossings Blvd.
Prince George, Virginia 23875

Dear Tracy:

Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC to quantify ammonia (NH_3) emissions at the outlet of the General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Three (3) 30-minute ammonia emission tests were performed at the gas turbine stack on January 19, 1998. Average emissions test results are summarized on the following computer printout titled "Summary of Results - Ammonia."

The methodology which was used to collect the emission samples is discussed in the July 1, 1996 edition of the Environmental Protection Agency (EPA) document EPA Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Method 4, and in the Bay Area Air Quality Management District (BAAQMD) Source Test Procedure ST-1B. A brief description of the test method follows:

EPA Method 4 - Ammonia (NH_3)

The sample train used for quantifying ammonia emissions is illustrated in the figure titled "EPA Method 4 Sample Train" included in the attached data package. The Method 4 sample train was modified to collect ammonia (NH_3) using the BAAQMD source test procedure ST-1B. A pump was used to pull the stack gas through a heated probe liner into an impinger train which was immersed in an ice water bath. The first and second impingers were modified Greenburg-Smith type impingers each containing 100 milliliters of 0.1 N hydrochloric acid (HCl) to absorb ammonia. The third impinger was empty, and the fourth bubbler contained indicating silica gel desiccant to absorb any moisture from the stack gas before it entered the control box. The impinger section was maintained at a temperature below 45° F by keeping the train in an ice-water bath. The temperature at the outlet of the silica gel bubbler was monitored to

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AIR QUALITY LLC

SUMMARY OF RESULTS - AMMONIA
AM TEST-AIR QUALITY, LLC

File Name: JAA\97-190WD\M4\NH3SUM
Client: Cogentrix of Vancouver
@ Clark Public Utilities
Location River Road Generating Project
Vancouver, Washington

	GENERAL ELECTRIC MODEL 7231FA GAS TURBINE				
	RUN #1	RUN #2	RUN #3	AVERAGE	BLANK
Lab #:	2353	2354	2355		
Date:	12/8/97	12/8/97	12/8/97		
Start Time:	1430	1515	1600		
Stop Time:	1500	1545	1630		
Sample Length (minutes):	30.0	30.0	30.0		
Volume Sampled (dscf):	24.637	23.869	23.661	24.056	24.056
Volume Sampled (dscm):	0.698	0.676	0.670	0.681	0.681
Impinger Catch Solution					
Ammonia Detection Limit (µg/ml):	0.005	0.005	0.005		0.005
Liquid Volume of Sample (ml):	340	338	350		300
Dilution Factor:	1	1	1		1
Ammonia Detection Limit (µg):	1.7	1.7	1.8		1.5
Ammonia In Impinger Solution (µg):	4	< 2	2	3	< 1.5
Ammonia (NH_3) Emissions					
Ammonia Concentration in Sample (mg):	0.004	< 0.002	0.002	~ 0.003	< 0.002
Ammonia Emission Concentration (mg/dscm):	0.006	< 0.003	0.003	~ 0.004	0.002
Ammonia Emission Concentration (ppm):	0.008	< 0.004	0.004	~ 0.005	< 0.003

water bath. The temperature at the outlet of the silica gel bubbler was monitored to verify that it did not exceed 45° F. Prior to each run, the sample train was leak-checked following the procedures in Method 5. Upon completion of each test, the probe was removed from the stack and a post-test leak check was performed.

The impinger catch solutions were submitted to Am Test, Inc.'s Water Chemistry laboratory for NH_3 analysis using rapid flow analysis (RFA), which is a colorimetric analysis procedure. The laboratory analysis data were reported in units of micrograms (μg) per sample. Total NH_3 laboratory analysis results were converted to emission concentration units of milligrams per dry standard cubic meter (mg/dscm) and parts per million (ppm). An acceptable leak check of less than 0.02 cfm at the highest vacuum rate (or greater) used during the test preceded and followed each run.

Mr. Kevin P. Orton and Mr. Aaron C. Porter of Am Test-Air Quality, LLC performed the field sampling. Am Test, Inc. of Redmond, Washington performed the ammonia analysis of the Method 4/NH_3 samples. Am Test-Air Quality, LLC's laboratory and technical writing staff performed the sample recovery, data reduction, and quality assurance review. Ms. Judy A. Aasland prepared the final report. Ms. Angela F. Blaisdell and Mr. Kris A. Hansen performed the senior report review. Mr. Tracy Patterson of Congentrix of Virginia, Inc. in Prince George, Virginia coordinated this test program.

Please find enclosed three (3) copies of this letter and the data package which includes summary tables of results, separate computer printouts for each run, example calculations of results and field data sheets. Please call Am Test-Air Quality, LLC at (425) 222-7746 if you have any questions or require further information.

Sincerely,
Am Test-Air Quality, LLC

Kris A. Hansen, QEP
President

Enclosures
[gw3\jaa\c:\winword\rpt97ltr\cogentrxnh3; #97-190]

AMTEST
AIR QUALITY, LLC

AmTest-Air Quality,
30545 S.E. 84th St., #5
Preston, WA 98050
Office: (206) 222-7746
FAX: (206) 222-7849

January 9, 1998

Mr. Tracy Patterson
Cogentrix Energy, Inc.
River Road Generating Project
5201 NW Lower River Road
Vancouver, Washington 98660

Dear Tracy,

Cogentrix of Vancouver, Inc. contracted Am Test-Air Quality, LLC to quantify ammonia (NH_3) emissions at the outlet of the General Electric (GE) Model 7231FA gas turbine installed at Clark Public Utilities' River Road Generating Project in Vancouver, Washington. The project was constructed by Cogentrix of Vancouver, Inc. in Vancouver, Washington. Three (3) 30-minute ammonia emission tests were performed at the gas turbine stack on December 8, 1997. Average emissions test results are summarized on the following computer printout titled "Summary of Results - Ammonia."

The methodology which was used to collect the emission samples is discussed in the July 1, 1996 edition of the Environmental Protection Agency (EPA) document EPA Title 40, Code of Federal Regulations, Part 60 (40 CFR 60), Appendix A, Method 4, and in the Bay Area Air Quality Management District (BAAQMD) Source Test Procedure ST-1B. A brief description of the test method follows:

EPA Method 4 - Ammonia (NH_3)

The sample train used for quantifying ammonia emissions is illustrated in the figure titled "EPA Method 4 Sample Train" included in the attached data package. The Method 4 sample train was modified to collect ammonia (NH_3) using the BAAQMD source test procedure ST-1B. A pump was used to pull the stack gas through a heated probe liner into an impinger train which was immersed in an ice water bath. The first and second impingers were modified Greenburg-Smith type impingers each containing 100 milliliters of 0.1 N hydrochloric acid (HCl) to absorb ammonia. The third impinger was empty, and the fourth bubbler contained indicating silica gel desiccant to absorb any moisture from the stack gas before it entered the control box. The impinger section was maintained at a temperature below 45° F by keeping the train in an ice-

6

FINAL REPORT
1997 EMISSION COMPLIANCE TESTS AT THE CROCKETT COGENERATION FACILITY

Prepared For:

CROCKETT COGENERATION, L.P.
Crockett, California

For Submittal To:

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
San Francisco, California

Prepared By:

Kevin J. Crosby

CARNOT
Concord, California

AUGUST 1997

SECTION 1.0

INTRODUCTION

Carnot was contracted by Crockett Cogeneration, L.P. to perform the 1997 emission compliance tests at the Crockett Cogeneration facility adjacent to the C&H Sugar refinery in Crockett, California. The testing program included measurement of emissions at full load from Auxiliary Boiler B, and at full load on the gas turbine and heat recovery steam generator (HRSG). Additional tests were conducted on the gas turbine/HRSG unit during start up and shutdown conditions, but they are reported separately.

Emissions were measured as required by the proposed Permit to Operate (Application Number 17076) issued by the Bay Area Air Quality Management District (BAAQMD) to Crockett Cogeneration, a California Limited Partnership. Tests were performed to measure emissions of the following parameters:

- NO_x, CO, POC
- Ammonia
- Total particulate matter as PM_{10}

The results of these tests are presented in this report to determine compliance with the emission limit conditions of the Authority to Construct.

The tests were performed on June 16 through 18, 1997 by Kevin Crosby, John Pascale, and Jeff Hogan of Carnot. Unit operations were coordinated by Mr. Audun Aaberg of Crockett Cogeneration. No direct observations of the tests were made by BAAQMD personnel, but they were notified of the test schedule. The tests were conducted according to a test plan submitted by BAAQMD.

The average test results are summarized in Tables 1-1 through 1-3. Detailed results summaries for the individual test runs are presented in Section 4.0.

SECTION 2.0

FACILITY DESCRIPTION

The Crockett Cogeneration Project includes three auxiliary boilers and one combined-cycle gas turbine generator unit located adjacent to the C&H Sugar refinery in Crockett, California. The 240 MW cogeneration facility provides electrical power for Pacific Gas & Electric Co. (PG&E), and process steam and power to the C&H Sugar refinery. There are three identical Foster-Wheeler auxiliary boilers, all fired on natural gas. Each boiler unit includes a selective catalytic reduction (SCR) unit for control of NO_x emissions. The turbine unit includes a General Electric Frame 7FA combustion gas turbine and a heat recovery steam generator (HRSG). The HRSG includes supplementary duct burners for additional steam production, and a SCR unit for control of NO_x emissions. Emission limits imposed by the Authority to Construct are shown in Table 2-1.

The exhaust from each auxiliary boiler is ducted to a vertical, cylindrical stack. These three stacks are grouped together, and are immediately adjacent to the turbine/HRSG stack. The sampling locations for all four stacks are accessed from a single platform.

TABLE 4-1
EMISSION TEST RESULTS SUMMARY
GAS TURBINE UNIT
CROCKETT COGENERATION
JUNE 1997

Parameter	1-PM-GT	2-PM-GT	3-PM-GT	Average
Test Condition:	Full Load With Duct Burners			
ate:	6-16-97	6-17-97	6-17-97	
Time	0940-1207	1244-1539	1604-1813	
Stack Gas				
Temp., °F	213	221	225	220
Flow, dscfm	814,636	825,099	827,292	822,342
H_2O, % vol.	13.1	12.9	11.5	12.5
O_2, % vol. dry	12.3	12.3	12.5	12.4
CO_2, % vol. dry	4.9	5.0	4.9	4.9
NO_x, ppm @ 15% O_2	4.41	4.51	4.02	4.31
Ammonia, ppm @ 15% O_2	0.38	0.36	0.44	0.39
CO, ppm @ 15% O_2	1.04	1.05	1.24	1.11
Emission Rate, lb/hr				
NO_x as NO_2	37.32	38.86	35.01	37.06
CO	5.38	5.48	6.58	5.81
POC as CH_4	<0.02	0.02	<0.02	<0.02
Total PM as PM_{10}	0.47	1.00	0.87	0.78

Notes: PM denotes filterable particulate matter (front-half only), from EPA Method 5.
The gas turbine was at full load, with duct burner operations.

The Avogadro Group

6/98

FINAL REPORT FOR 1998 EMISSION COMPLIANCE TESTS AT CROCKETT COGENERATION CROCKETT, CALIFORNIA

Prepared for:

CROCKETT COGENERATION, L. P.
Crockett, California

for Submittal to:

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
San Francisco, California

And to:

CALIFORNIA ENERGY COMMISSION
Sacramento, California

Prepared by:

Kevin J. Crosby Kevin J. Crosby
July 24, 1998

R98045

1.0 INTRODUCTION

The Avogadro Group (AG) was contracted by Crockett Cogeneration (Crockett Cogen) to perform a series of emission source tests. The testing program was conducted to determine compliance with the conditions of the Permit to Operate issued by the Bay Area Air Quality Management District (BAAQMD). Emissions were measured from one gas turbine with heat recovery steam generator (HRSG), and from one of three auxiliary boilers.

The testing data and results for emissions of criteria pollutants are presented in this report, which includes descriptions of the facility and the sampling locations, and descriptions of the testing procedures, calculations and quality assurance data. A separate report has been prepared for the emissions of toxic air contaminants.

The testing program was conducted on June 15 to 23, 1998 by Kevin Crosby, Erick Mirabella, Jeff Hogan and Dan Duncan of The Avogadro Group. Unit operations were coordinated by Audun Aaberg of Crockett Cogeneration, with the assistance of the shift supervisors and board operators that were on shift during the tests. The BAAQMD was notified of the test schedule, but no direct observations of the tests were made by District personnel.

The average test results are summarized in Tables 1-1 and 1-2. Detailed results summaries for the individual test runs are presented in Section 4.0.

TABLE 1-2
SUMMARY OF AVERAGE TEST RESULTS
GAS TURBINE / HRSG UNIT
CROCKETT COGENERATION
JUNE, 1998

Parameter	Average Result	Permit Condition
Stack Gas		
Temperature, °F	217	-
Flow, dscfm	821,249	-
H_2O, % vol	14.1	-
O_2, % vol dry	12.60	-
CO_2, % vol dry	4.88	-
Concentration, ppm @ 15% O_2		
NO_X	3.27	5.0
CO	2.02	5.9
Ammonia	0.12	20
Emission Rate, lb/MMBTU		
NO_X as NO_2	0.0120	-
CO	0.0046	-
Total PM as PM_{10}	0.0013	-
Emission Rate, lb/hr		
NO_X as NO_2	26.91	39.2
CO	10.13	16.6
POC as Methane	0.116	-
Total PM as PM_{10}	2.82	-

Note: There are other permit conditions that have not been directly addressed in this table. The data presented here can be used in calculations to address those daily and annual emission rate limits.

2.0 EMISSION SOURCE INFORMATION

2.1 Facility Description

The Crockett Cogeneration facility includes one combined-cycle gas turbine generator unit and three auxiliary boilers located adjacent to the C&H Sugar refinery in Crockett, California. The 240 MegaWatt cogeneration facility provides electrical power for Pacific Gas & Electric Company (PG&E), and process steam to C&H Sugar.

The turbine unit is a General Electric 7FA combustion gas turbine with steam augmentation, and with a steam turbine that applies power to the same output shaft for generation of electricity. The exhaust gases from the turbine flow horizontally through a heat recovery steam generator (HRSG). The Vogt HRSG includes supplementary duct burners for additional steam production, and SCR and reduction catalysts for control of NO_x, CO and other emissions. The exhaust gases from the gas turbine and HRSG are ducted to a vertical, cylindrical stack.

There are three identical Foster-Wheeler auxiliary boilers, each fired with natural gas and rated at approximately 40,000 lb/hr steam production. Each boiler unit includes a selective catalytic reduction (SCR) unit for control of NO_x emissions. The exhaust from each boiler is ducted to a vertical, cylindrical stack. These three stacks are grouped together, and are immediately adjacent to the turbine/HRSG stack. The sampling locations for all four stacks are accessed from a single platform.

2.2 Emission Source Description

The turbine/HRSG exhausts through a vertical, cylindrical stack that is 233 feet tall. The stack has an inside diameter of 16.5 feet (198.0 inches) and has a number of sampling ports, some of which are used for the unit's CEMS. Four of the ports that are available for use in testing are 90 degrees apart in the same horizontal plane, and are 4-inch pipe with flanges (150 psi rating type) and caps. The ports are 60 feet downstream from (or above) the stack dampers, and 100 feet upstream from the top of the stack. Access to the platform at 128 feet is by stairway to the top of the HRSG, then by ladder the last 60 feet.

A total of 24 sampling traverse points were located according to BAAQMD Method ST-18 (EPA Method 1). Six points were used in each of the four sampling ports.

Each auxiliary boiler exhausts through a vertical, cylindrical stack that is 233 feet tall. Each stack has an inside diameter of 6.0 feet (72.0 inches) and has two sampling ports. The ports are 90 degrees apart in the same horizontal plane, and are 4-inch pipe with flanges (150psi rating type) and caps. The ports are at least 60 feet downstream from (or above) the last disturbance in the flow, and 100 feet upstream from the top of the stack. Access to the ports is from the same large platform used for the turbine/HRSG stack

A total of 12 sampling traverse points were located according to BAAQMD Method ST-18 (EPA Method 1). Six points were used in each of the two sampling ports.

7

HITACHI AMERICA, LTD. 660 White Plains Road Tarrytown, NY 10591

Fax

Date: 8/13/1998

Number of pages including cover sheet: 1

To: Environmental Management

Attn: Phyllis Fox

Regarding: Catalyst Information

Phone: 510-843-1126

Fax phone: 510-845-0983

CC: D. Brozek (HAL)

From:

John Calvello

Sales Engineer

Power and Industrial Division

Phone: (914) 524-6631

Fax phone: (914) 332-5388

REMARKS: ☐ Urgent ☒ For your review ☐ Reply ASAP ☐ Please comment

In response to your talks with David Brozek on Thursday, 8/12, following is some information I can provide in regards to your request. It would take me additional time to gather additional information from Japan and prepare details as you have requested.

In regards to efficiency levels you are requesting we have a plant in Japan that is running at a 93% efficiency level, NOx out of 3ppm, and an ammonia slip of 3ppm. The plant is Yokohama 8, which consists of 4units, frame 9 gas turbines. I have attached some design data on this plant for your reference.

There are two plants going under construction in the southeast U.S.. The first plant is schedule to go online in August/September 1999. The outlet requirements for this plant are 2ppm with an ammonia slip of 10ppm. The second plant is scheduled for 2000. The outlet NOx has not been confirmed yet. The options for this plant are for 2, 3.5, and 4ppm. I should have confirmation on the required level by the end of September.

In general, there is no problem in supplying guarantees to meet both a 2ppm NOx outlet and an ammonia slip of 5ppm. The only consideration is the overall capital cost. These levels can be met by increasing the catalyst volume. I will try to gather additional information on temperature thresholds and operating temperatures for you.

We have recently quoted a confidential project that is to occur in the Northeast. It will be approximately 2000MW facility. I believe they will utilize Westinghouse 501G GT. The requirements quoted were a 3.5 and 2ppm outlet NOx with an ammonia slip of 5ppm or less. Budgetary equipment and catalyst cost are as follows;

Σ ONE SYSTEM — Catalyst, Ammonia Injection Grid, Ammonia flow control skid, Catalyst support structure, Outer reactor housing:
3.5ppmvd - $1,700,000. OR 2.0ppm - $1,950,000.

I hope this current information is helpful. If there are any questions please feel free to contact me.

Sincerely,

John Calvello

0 −(1) 現在、計画、[illegible]中の脱硝装置計画仕様

	No.	項目	単位	CONFIDENTIAL		YOKOHAMA 8	CONFIDENTIAL	
				計画 / 実績	計画 / 実績	計画 / 実績	計画 / 実績	計画 / 実績
CAPACITY	1	ボイラ容量	(MW)	[illegible]00 (400)	670 (380)	1400 (400)	1650 (700)	158 (180)
FUEL	2	燃料		LNG (0)	LNG (0)	LNG (0)	LNG (0)	[illegible] (7[illegible])
GAS FLOW RATE	3	処理ガス量	Nm³/h	L0[illegible],000×4 (4缶)	1,2[illegible],300×3 (4缶)	1,2[illegible],000×4 (8缶)	1,2[illegible],340 (8缶)	1,2[illegible] (8缶)
GAS TEMP.	4	処理ガス温度	℃	33[illegible]	337	33[illegible]	33[illegible]	
OPERATION START	5	運転開始	−	198[illegible]−12 (12月)	1985−12− 1986−7	198[illegible]−7− 198[illegible]−7	198[illegible]−7− 198[illegible]−1	198[illegible]−[illegible]−
	6							
INLET NOx	7	入口NOx濃度	ppm	52.5([illegible])	54.3([illegible])	40([illegible])	50([illegible])	52.5([illegible])
OUTLET NOx	8	出口NOx濃度	ppm	22.5([illegible])	8.7([illegible])	30([illegible])	60([illegible])	6.25([illegible])
EFF.	9	脱硝率	%	>80	85	[illegible]	[illegible]	90
MOLE RATIO	10	NH₃/NOxモル比	−	0.902	0.90[illegible]	1.0		
	11	Slip NH₃	ppm	[illegible]	5 ([illegible])	10([illegible])	5([illegible])	10([illegible])
	12	SOx (SO₃)	ppm	3	[illegible]	0	0	0.2(0.2)
DUST	13	ダスト	mg/Nm³	3	0	0	0	0
	14	O₂ (H₂O)	%	12.6 ([illegible])	11.0 ([illegible])	12.9 ([illegible])	12.8 ([illegible])	11.3 ([illegible])
	18	LV (LVA)	m/sec	7.2([illegible])	6.2([illegible])	7.0([illegible])	5.8([illegible])	5.7([illegible])
	20	N Cata	m	2.5	2.6	2.5	2.75	2.3
	21	全ΔP (Cata含)	mmAq	<100	<[illegible]	<[illegible]	<100	<[illegible]
	22	ΔP Cataのみ	mmAq					
	23	SO₂酸化率	%					
	24	ΔSO₃	ppm					
	25	[illegible]	−					
	27	[illegible]		([illegible]×2[illegible])×5段=2080	(20"×28")×4段=2240	(20"×38")×5段=3800	([illegible]×30")×5段=2700	([illegible]×3[illegible])×6段=2220
	28	ユニット[illegible]		2080×4=8320	2240×3=6720	3800×4=15200	2700×7=18900	2220×1=2220
	28-1	[illegible]		[illegible]. 2. [illegible]	2. 2. [illegible]	3. 2	[illegible]. 2. [illegible]	3. 3
	29	[illegible]	℃					
	30	R/C サイズ	m	([illegible].5"×[illegible])×7段	(11.2"×15.0")×7.5	(13.5"×[illegible])×7段	([illegible].5"×15.6")×7.5	(5.5"×[illegible])×7.5
	31	重量	TON					
	32	[illegible]	−					
FRAME TYPE	33	備考		FTP	FTFA	FSF	FTFA	FSEA

8

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 2
290 Broadway
New York, NY 10007-1866

September 27, 2000

Mr. Robert L. Ewing
Project Manager
New York State Department
of Environmental Conservation
Division of Environmental Permits
50 Wolf Road
Albany, New York 12233-1750

Re: Prevention of Significant Deterioration of Air Quality (PSD)
Proposed Sithe Heritage Station Generating Facility, Scriba, New York

Dear Mr. Ewing:

The Region 2 Office of the U.S. Environmental Protection Agency (EPA) has reviewed the August 8, 2000 draft PSD permit prepared by the New York State Department of Environmental Conservation (NYSDEC) for the Heritage Power, L.L.C.'s proposed facility in Scriba, New York. Based on our review, we have determined that the permit applicant has not demonstrated that 2-4 ppm CO (or less) is not best available control technology (BACT) for this facility. Therefore, the proposed CO BACT emission concentration of 7.2 ppm at 15% O_2 and 45.1 lb/hr, achieved through efficient combustion techniques, cannot be considered BACT. (Please note that although the draft PSD permit lists the CO emission rate as 45.0 lb/hr and 7.0 ppmvd at 15% O_2, it is our understanding that the permit applicant has requested that the proposed limit reflect the actual permit application. NYSDEC has tentatively agreed to change the permitted emission rates to 45.1 lb/hr and 7.2 ppmvd at 15% O_2).

By way of background, Heritage Power, L.L.C. proposes to construct and operate a new combined-cycle electric generating facility consisting of two new General Electric (GE) Steam and Gas (STAG) 107H system combustion turbine generators, two heat recovery steam generators (without supplementary duct firing), two steam turbine generators, one auxiliary boiler and one emergency generator. The primary fuel will be natural gas with 0.05% low sulfur fuel oil as backup. The nominal electric generating capacity of the proposed facility will be approximately 800 megawatts. The proposed facility's current potential to emit for the pollutant CO is 399 tons/year (based on a 45.1 lb/hr CO emission rate per turbine or 395 tons/year for both turbines and approximately 4 tons/year from the auxiliary boiler and emergency generator). The applicant provided two cost analyses for the installation of a CO catalyst (based on an uncontrolled 42 lb CO/hr [6.7 ppm] to a post-controlled 6.29 lb CO/hr [1.0 ppm] with an 85% control efficiency). The first cost analysis, from Engelhard, has a cost per ton of CO removed of $3,126. The second cost analysis, which includes the original Engelhard estimate plus the estimated markup of $439,000 for the Heat Recovery Steam Generator (HRSG) vendor and the Engineering, Procurement and Construction (EPC) contractor, has a cost per ton removed of $3,708.

However, since the draft permit has a 45.1 lb/hr (7.2 ppm) CO emission limitation and not 42 lb/hr (6.7 ppm), EPA recalculated the above costs starting with 7.2 ppm down to 1.0 ppm. This yields costs of $2,876 per ton of CO removed for the first cost analysis and $3,412 per ton of CO removed for the markup cost analysis. EPA considers these two cost analyses ($2,876 and $3,412) to be an acceptable cost for BACT purposes. Therefore, EPA deems the installation of a CO catalyst to be BACT for this proposed facility since this will provide the CO emission concentration that will be similar to recent proposed/final CO BACT determinations.

Some of the recent PSD permits issued or under review have required or proposed the following CO limits with a CO catalyst:

1. Sithe Mystic Development (1550 MW), MA - 2 ppm CO
2. Cabot Power (350 MW), MA - 2.0 ppm CO
3. ANP Blackstone (580 MW), MA - 3.0 ppm CO
4. ANP Bellingham (580 MW), MA - 3.0 ppm CO
5. Dighton Power (170 MW), MA - 4.0 ppm CO
6. Mantua Creek (881 MW), NJ - 3.0 ppm CO
7. AES Red Oak (816 MW), NJ - 4.0 ppm CO
8. PDC- El Paso Milford LLC (540 MW), CT - 2.0 ppm CO
9. Lake Road Generating (792 MW), CT - 3.0 ppm CO
10. Calpine - Sutter Power (500 MW), CA - 4.0 ppm CO
11. High Desert Power Project (700 MW), CA - 4.0 ppm CO

Based on information that we have, it is not clear to us why Heritage Power, L.L.C cannot achieve the same level of CO control that these projects have.

It is GE's position that this new GE STAG 107H turbine is an inherently cleaner unit which achieves low emissions through pollution prevention. An August 30, 2000 letter addressed to me from Messrs. Joel Chalfin and Thomas O. Dreisbach, Jr. of GE Power Generation states, in pertinent part, that "...Heritage Power is the U.S. launch site for GE's next generation of turbine technology, which is referred to as the 7H." "...To achieve the 7H efficiency target while minimizing the environmental impacts requires the use of the proven combustion technology from GE's 'FA' class gas turbines." " GE's data collected to date on 7FA gas turbines has demonstrated that **every unit tested has emissions of ...CO measured below U.S. EPA Method 10 detection levels** [emphasis in the original]. Measured data from fourteen 7FA gas turbines ...document base load CO levels averaging well below 2 ppmvd @ 15% O_2. We expect the data shown to be representative of the 7H."

While EPA understands that the new GE STAG 107H model turbines have not been thoroughly field tested, EPA sees the following options available to GE to avoid the installation of a CO catalyst:

1. **80%-20% Option** - GE has stated that based on actual data collected from GE's existing 7FA gas turbines, GE expects the new 7H gas turbines to emit well below 2 ppm CO @ 15% O_2 during base load operations. Generally for CO, extreme ambient conditions concurrent with part load operations will make these turbines achieve a CO concentration of 7 ppm. For Heritage Power, according to GE, extreme ambient conditions are expected at -19°F and 100% relative humidity, which are experienced very infrequently at the site for this proposed facility. Based on these facts, as presented to us, it would not be unreasonable to require that during at least 80% of the time (7,008 hours/year) the facility should achieve a CO concentration of 3.0 ppm or less and during the remaining 20% of the time (1,752 hours/year) the facility should achieve a CO concentration of 7.2 ppm or less to account for extreme ambient conditions coupled with part load operations. Under this approach, the CO potential to emit from each of the two turbines would be approximately 105 tons/year and a recalculation of the CO BACT analysis would provide for a cost-per-ton removed of well over $6,000 per ton. If this is the case, the installation of the CO catalyst would not be BACT.

2. **Innovative Control Technology Waiver for CO** - EPA regulations allow the installation of new technology that has not yet been proven under the auspices of the innovative control technology waiver. Innovative control technology means "any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emission reduction than any control system in current practice or of achieving at least comparable reductions at lower costs in terms of energy, economics, or nonair quality environmental impacts." In general, what this would mean in practice is that the applicant will be given a period of no more than three years to come into compliance with the BACT level determined at the time of the permit issuance. If the facility fails to achieve this level of BACT at the end of this period, the applicant is then committed to install the CO oxidation catalyst. Given the current stage of the permitting process for this project, if the applicant decides to pursue this waiver, EPA will work with NYSDEC on a timely manner to expedite the development of the permit conditions/approvals required for this waiver.

If you need to discuss this further, please contact me at (212) 637-4074 or Frank Jon at (212) 637-4085.

Sincerely,

/s/

Steven C. Riva, Chief
Permitting Section
Air Programs Branch

cc: John Higgins, NYSDEC - Albany
Reginald Parker, NYSDEC Region 7

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California Air Resources Board

HOME SEARCH SITE MAP SOFTWARE CONTACT US

Best Available Control Technology (BACT) Clearinghouse Program

This page updated July 25, 2000.

The BACT Clearinghouse is managed by the ARB under the direction of the California Air Pollution Control Officers Association (CAPCOA) Engineering Managers Committee. Products available at this area of the website include a searchable database for California BACT and "lowest achievable emission rate" (LAER) determinations dating back to 1985.

The clearinghouse publishes an information manual which includes a set of BACT tables which is available for downloading in html format. While the BACT Manual was published in hard copy on November 24, 1993, the tables are routinely updated for this website. The last date of update is shown below alongside the link.

Information on determinations is submitted to the Clearinghouse on a voluntary basis by California districts. Therefore, the database does not represent a comprehensive compilation of BACT determinations in California. If you have any questions regarding a specific determination, please contact the district individual identified in the database. If this person is not available, one may seek information from the district contacts provided in our BACT Contacts List .

BACT Database

- **Summary of Recent Submissions** - August 26, 1998 through July 10, 2000
- **Search the BACT Database** - Last Updated July 25, 2000

BACT Compilation Document

- The Introduction - Last Updated November 24, 1993 (WP6 Compressed with PKZIP.EXE) (250K)
- The Tables - Last Updated July 18, 2000 (HTML Compressed with Winzip) (119K)

Other Related Websites

Further information on BACT and LAER is available on at least four other websites:

- Bay Area AQMD BACT Guideline
- San Joaquin Valley APCD
- South Coast AQMD BACT Guideline
- U.S. EPA RACT/BACT/LAER Clearinghouse

Questions or comments can be addressed to Mike Tollstrup.

Top of page
Permitting - Related Activities

A department of the California Environmental Protection Agency

BACT Clearinghouse Database Lookup Results

34 Match(s) for Code 17.1

Boilers (Gas Fired) - <= 33.55 MMBtu/hr heat input

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
Margaretis Textile Service/MTS Inc. 4.2 MMBtu/hr Kewanee model 100 H.P. natural gas-fired fire-tube boiler for use with a steam generator (Detailed Information)	3/16/00 (A/C # 366323) A310-988-00 District Contact: Sam Barros South Coast AQMD (909) 396-2364 sbarros@aqmd.gov	**NOx** (Detailed Control Information) Goal Line Environmental Technologies SCONOx catalytic absorption system 2 ppmvd @ 3% O2 at applicant request (currently 2 ppmvd @ 3% O2 is not recognized as achieved in practice) ------------------------------
San Bernardino County Medical Center 6 MMBtu/hr Cleaver Brooks model FLX-700-600 natural gas-fired water-tube boiler use for building heat. LPG used as emergency backup fuel. Unit will be used from November through March. (Detailed Information)	2/15/00 (A/C # 364142) A340-986-00 District Contact: Sean Cullins South Coast AQMD (909) 396-2655 scullins@aqmd.gov	**NOx** (Detailed Control Information) Alzeta model CSB ultra low-NOx burner 12 ppmvd @ 3% O2 (natural gas) 30 ppmvd @ 3% O2 (LPG) ------------------------------ **CO** (Detailed Control Information) Alzeta model CSB ultra low-NOx burner 50 ppmvd @ 3% O2 (natural gas) 400 ppmvd @ 3% O2 (LPG) ------------------------------
Maruchan, Inc. 8.18 MMBtu/hr Miura model LX-200SG natural gas-fired water-tube boiler use as the main boiler for process heating operating above 80% capacity (Detailed Information)	9/9/99 (A/C # 358116) A340-985-00 District Contact: Darrell Johnson South Coast AQMD (909) 396-2230 djohnson@aqmd.gov	**NOx** (Detailed Control Information) Miura ultra low-NOx burner 15 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) No control 100 ppmvd @ 3% O2 ------------------------------
	3/10/00	**NOx** (Detailed Control Information) Industrial Combustion low-NOx

Bumble Bee Seafoods, Inc. 16.8 MMBtu/hr Superior Mohawk model 4X-2007-S150 natural gas-fired fire-tube boiler (Detailed Information)	(A/C # 365228) A310-983-00 District Contact: Doug Gordon South Coast AQMD (909) 396-2683 dgordon@aqmd.gov	burner with flue gas recirculation 12 ppmv @ 3% O2 ------------------------------ **CO** (Detailed Control Information) No control 50 ppmv @ 3% O2 ------------------------------
L&N Uniform Supply Co Inc. 6.3 MMBtu/hr Superior Boiler Works model 5-ACT-625-150M natural gas-fired fire-tube boiler (Detailed Information)	4/6/00 (A/C # 367150) A310-982-00 District Contact: Roy Olivares South Coast AQMD (909) 396-2208 rolivares@aqmd.gov	**NOx** (Detailed Control Information) American Combustion Technology model ACT-04 low-NOx burner with flue gas recirculation 12 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) No control 100 ppmvd @ 3% O2 ------------------------------
La Paloma Generating Co. LLC 6.2 MMBtu/hr Cleaver Brooks model CBW7XX-150-150 natural gas-fired fire-tube boiler use as part of a cooling two blowdown water treatment process (Detailed Information)	2/1/00 (A/C # S-3412-12-0) A310-973-00 District Contact: Leonard Scandura San Joaquin Valley Unified APCD (661) 326-6900	**NOx** (Detailed Control Information) Alzeta model CSB low-NOx burner 12 ppmv @ 3% O2 ------------------------------ **PM** (Detailed Control Information) No control 0.007 lb/MMBtu ------------------------------ **VOC/HC** (Detailed Control Information) No control 30 ppmv @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Alzeta model CSB low-NOx burner 50 ppmv @ 3% O2 ------------------------------
		NOx

Hi-Country 20.9 MMBtu/hr Cleaver Brooks model CB 700 natural gas-fired fire-tube boiler use to supply steam to heat evaporators and pasteurizing (Detailed Information)	12/16/99 (A/C # 362566) A310-970-00 District Contact: Doug Gordon South Coast AQMD (909) 396-2683 dgordon@aqmd.gov	(Detailed Control Information) Alzeta model CSB ultra-low-NOx burner 9 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Alzeta model CSB ultra-low-NOx burner 100 ppmvd @ 3% O2 ------------------------------
Nation Wide Boiler 28.8 MMBtu/hr Donlee model 582-SAHF-650-N natural gas-fired portable water-tube type boiler that will be use as an emergency rental unit to provide hot water and steam. (Detailed Information)	3/15/00 (A/C # 364408) A310-968-00 District Contact: Roy Olivares South Coast AQMD (909) 396-2208 rolivares@aqmd.gov	**NOx** (Detailed Control Information) Alzeta model CSB22-SSO-30 low-NOx burner 9 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Alzeta model CSB22-SSO-30 low-NOx burner 50 ppmvd @ 3% O2 ------------------------------
Santa Monica - UCLA Medical Center 16,300,000 Btu/hr Cleaver Brooks model CB(LE) 200-400 natural gas-fired, fire-tube boiler use to produce hot water and steam. Load following, with short periods of steady-state operation. Amber 363 backup fuel. (Detailed Information)	1/28/00 (A/C No.: 363025) A310-967-00 District Contact: Sean Cullins South Coast AQMD (909) 396-2655 scullins@aqmd.gov	**NOx** (Detailed Control Information) Cleaver Brooks, model LE low-NOx burner with flue gas recirculation 15 ppmvd @ 3% O2 while fired on natural gas 40 ppmvd @ 3% O2 while fired on AMBER 363 ------------------------------ **CO** (Detailed Control Information) Cleaver Brooks, model LE low-NOx burner with flue gas recirculation 50 ppmvd @ 3% O2 ------------------------------
Pacific Life Insurance 2,970,000 Btu/hr Parker model T-2970LR natural gas-fired boiler use for space heating (Detailed Information)	1/28/00 (A/C No.: 362486) A330-964-00 District Contact: Sean Cullins South Coast AQMD (909) 396-2655 scullins@aqmd.gov	**NOx** (Detailed Control Information) Parker model MFB-36, premix metal fiber ultra low-NOx burner 12 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Parker model MFB-36, premix metal fiber ultra low-NOx burner 100 ppmvd @ 3% O2 ------------------------------

Y2K Textile, Inc. 16,400,000 Btu/hr Superior model 6X-2000-S150-LNDG210P-20 natural gas-fired fire-tube boiler use to produce steam. (Detailed Information)	1/5/00 (A/C No.: 362616) A310-962-00 District Contact: Kien Huynh South Coast AQMD (909) 396-2635 khuynh@aqmd.gov	**NOx** (Detailed Control Information) Applied Utility Systems model PSCR selective catalytic reduction and low-NOx burners with flue gas recalculation. Ammonia slip limited to 5 ppmvd @ 3% O2. 11 ppmvd @ 3% O2 Limit is not yet considered as achieved in practice BACT ----------------------------- **CO** (Detailed Control Information) Low-NOx burners with flue gas recalculation 50 ppmvd @ 3% O2 -----------------------------
Damapong Textiles 16,500,000 Btu/hr Sellers Engineering model 105E-395 HP natural gas-fired fired-tube boiler use to provide steam for a dye tank. (Detailed Information)	12/7/99 (A/C No.: 359772) A310-961-00 District Contact: Kien Huynh South Coast AQMD (909) 396-2635 khuynh@aqmd.gov	**NOx** (Detailed Control Information) Peerless selective catalytic reduction. Ammonia slip limited to 5 ppmvd @ 3% O2 7 ppmvd @ 3% O2 NOx level is not now considered as achieved in practice BACT for this boiler size. ----------------------------- **CO** (Detailed Control Information) No control 50 ppmvd @ 3% O2 -----------------------------
General Dyeing and Finishing, Inc. 13.5 MMBtu/hr natural gas-fired Kewanee model H3S400G fire-tube boiler use to produce high pressure steam. (Detailed Information)	10/28/99 (A/C No.: 355513) A310-959-00 District Contact: Rod Millican South Coast AQMD (909) 396-2591 rmillican@aqmd.gov	**NOx** (Detailed Control Information) Energy and Environmental, Inc. ultra low-NOx burner. 5 ppmv @ 3% O2 (This NOx level is not yet considered as achieved in practice BACT for this boiler size.) ----------------------------- **CO** (Detailed Control Information) Energy and Environmental, Inc. ultra low-NOx burner. 50 ppmv @ 3% O2 -----------------------------
Coca Cola	11/23/99 (A/C No.: 352348)	**NOx** (Detailed Control Information) Coen Micro-Pak low-NOx burner and Peerless Mfg. Company selective catalytic reduction system. Ammonia

31.5 MMBtu/hr natural gas-fired Scotch Marine custom fire-tube boiler use to provide steam for sanitation (Detailed Information)	A310-947-00 District Contact: Doug Gordon South Coast AQMD (909) 396-2683 dgordon@aqmd.gov	slip limited to 5 ppmvd @ 3% O2. 7 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Coen Micro-Pak low-NOx burner 50 ppmvd @ 3% O2 ------------------------------
Disneyland Resorts Cleaver Brooks, model FLX, natural gas-fired water-tube boiler with a 8.5 MMBtu/hr Alzeta Model CSB84 ultra low-NOx burner. Boiler is used to supply hot water to a hotel. (Detailed Information)	12/21/99 (A/C No.: 360389) A310-946-00 District Contact: Roy Olivares South Coast AQMD (909) 396-2208 rolivares@aqmd.gov	**NOx** (Detailed Control Information) Alzeta ultra low-NOx burner 12 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Alzeta ultra low-NOx burner 50 ppmvd @ 3% O2 ------------------------------
SCHI Santa Monica Beach Hotel Associates 4.292 MMBtu/hr Clayton, model E6100-LNB, natural gas-fired water-tube boiler use to supply hot water (Detailed Information)	12/2/99 (A/C No.: 362396) A310-945-00 District Contact: Roy Olivares South Coast AQMD (909) 396-2208 rolivares@aqmd.gov	**NOx** (Detailed Control Information) Ultra low-NOx burner system 12 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Ultra low-NOx burner system 100 ppmvd @ 3% O2 ------------------------------
Alta Dena Dairy Three 16.7 MMBtu/hr (400 bhp), Cleaver Brooks model CB700, fire tube type package boiler to produce steam. for dairy production equipment. One boiler was equipped with low temp. oxidation for a demonstration project, not BACT. (Detailed Information)	2/5/92 (A/C no. 259724) A310-879-99 District Contact: Arturo Arreola South Coast AQMD (909) 396-2534 aarreola@aqmd.gov	**NOx** (Detailed Control Information) Cannon Technology low temperature oxidation system 40 ppmvd @ 3% O2 (Source tests show emissions of 5 ppmvd @ 3% O2, but technology did not operate enough to be achieved in practice. Ozone slip is limited to 1 ppmvd @ 15% O2.) ------------------------------ **CO** (Detailed Control Information) Cannon Technology low temperature oxidation system 100 ppmvd @ 3% O2 (Three source tests over 10 months measured CO levels no higher than 8.1 ppmvd @ 3% O2, but did not operate enough to be achieved in practice) ------------------------------
		NOx

Doctors Medical Centers 3.78 MMBtu/hr natural gas-fired boiler with low sulfur #2 fuel oil backup (Detailed Information)	1/5/98 (A/C no. N-2333-10-0) A310-824-98 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	(Detailed Control Information) Industrial Combustion burner and FGR 30 ppmvd @ 3% O2 ----------------------------- **SOx** (Detailed Control Information) Natural gas as primary fuel with low sulfur fuel oil #2 (0.05% by weight) as backup No limit (Equivalent to 4.6 lbm/day) -----------------------------
California State Prison, Corcoran 8.1 MMBtu/hr Clayton Industries Model SEG-204-2-LNB boiler (Detailed Information)	1/15/97 (A/C no. C-0214-32-0) A310-792-97 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) or (Performance Information) Premixed lean burn combustion technology 12 ppmv at 3% Oxygen -----------------------------
Toter, Incorperated 5.6 MMBtu/hr polyethylene curing oven incorporated with a Ferry RS-370 (Detailed Information)	9/9/96 (A/C no. C-43-6-0) A310-778-97 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) No control Natural gas, emissions < 0.07 lb/MMBtu @ 1000 Btu/SCF -----------------------------
Kern Medical Center 2.8 MMBtu/hr gas-fired PVI Industries model 3500 boiler limited to 80% utilization with diesel backup (discovered source) (Detailed Information)	1/27/97 (A/C no. S-1678-11-0) A350-775-97 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) No control (The use of low NOx burners and flue gas recirculation were found not to be cost effective for the subject boilers) No limit -----------------------------
CalResources LLC Modificatin of 13.6 MMBtu/hr Solar model 1100 Saturn gas turbine fired on natural gas driving a gas compressor. Unit has some heat recovery. (Detailed Information)	1/10/97 (A/C no. S-1543-5-3 and -6-3) A330-765-97 District Contact: George Heinen San Joaquin Valley Unified APCD	**NOx** (Detailed Control Information) No control 69 ppmvd at 15% oxygen 3.61 lbm/hr w/o duct burner off -----------------------------

	(559) 230-5909	
Darling International Inc. 31.2 MMBtu/hr Nebraska model NS-B-40 boiler at a rendering plant using natural gas with fuel oil no. 2 firing allowed during natural gas curtailment (Detailed Information)	12/30/96 (A/C no. C-406-3-1) A310-761-97 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) Low-NOx burner and flue-gas recirculation 0.036 lbm/MMBtu on natural gas 0.052 lbm/MMBtu on fuel oil no. 2 ------------------------------ **PM** (Detailed Control Information) No control 0.0137 lbm/MMBtu for natural gas 0.014 lbm/MMBtu for fuel oil no. 2 ------------------------------ **CO** (Detailed Control Information) No control 0.089 lbm/MMBtu on natural gas and fuel oil no. 2 ------------------------------
O.H. Kruse Grain and Milling Division of PM Ag Products, Inc. 10 MMBtu/hr (300 hp) Clayton Model EG 300 boiler used as a backup to a 21 MMBtu/hr (500 hp) boiler; use limited to 7 billion Btu/yr (Detailed Information)	9/19/96 (A/C no. S-160-13-0) A370-751-97 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) No control 0.106 lb/MMBtu 25.4 lbm/day ------------------------------ **PM** (Detailed Control Information) No control 0.012 lbm/MMBtu 2.9 lbm/day ------------------------------ **VOC/HC** (Detailed Control Information) 10 MMBtu/hr (300 hp) Clayton Model EG 300 boiler used as a backup to a 21 MMBtu/hr (500 hp) boiler; use limited to 7 billion Btu/yr ------------------------------
		NOx (Detailed Control Information) or (Performance Information) Zwick Energy model no. FC150-B-UV-LU low-emissions flameless buners

Vandenberg Air Force Base Two 8.4 MMBtu/hr, propane-fired Superior model no. 4-5-1024-W60-GP-G hot-water boilers (Detailed Information)	10/24/96 (A/C no. 9225) (PTO no 9225, issue date 2/27/97) A310-712-96 District Contact: Mike Goldman Santa Barbara Co. APCD (805) 961-8821 goldmanm@sbcapcd.org	15 ppmvd at 3% oxygen 0.15 lbm/hr Source test results: boiler 1: 7.2 ppmv @ 3% O2 boiler 2: 7.1 ppmv @ 3% O2 ------------------------------ **CO** (Detailed Control Information) or (Performance Information) Zwick Energy model no. FC150-B-UV-LU low-emissions flameless buners 50 ppmvd at 3% oxygen 0.31 lbm/hr Source test results boiler 1: <1 ppmv @ 3% O2 boiler 2: <1 ppmv @ 3% O2 ------------------------------
Children's Hospital of Orange Two identical 10,958,100 Btu/hr Kewanee model H3S-250-G0, 250 hp natural gas-fired boiler with low-NOx fuel oil backup (Detailed Information)	7/31/91 (App. No.: 246519 and 246521) A310-623-94 District Contact: Lisa H. Mirisola South Coast AQMD (909) 396-2638 lmirisola@aqmd.gov	**NOx** (Detailed Control Information) or (Performance Information) Vitotherm model VG0-2502 low-NOx gas and oil burner with induced draft flue gas recirculation and Centuray Controls oxygen trim system 30 ppmd @ 3% O2 ------------------------------
Aratex Services, Inc. 33.5 gas-fired Cleaver Brooks model CB200-800-150 firetube boiler rated at 800 hp output with distillate oil emergency backup fuel (Detailed Information)	2/3/93 (A/C no. 9840) A310-578-93 District Contact: Karen Dzienkowski Bay Area AQMD (415) 749-5141 kdzienkowski@baaqmd.gov	**NOx** (Detailed Control Information) or (Performance Information) Cleaver Brooks low NOx burners and flue-gas recirculation 25 ppmvd at 3% oxygen ------------------------------
Del Monte Foods, USA 20.9 MMBtu/hr gas-fired Johnston boiler (Detailed Information)	9/26/90 (A/C no. 30404020101) A310-472-91 District Contact: Martin Keast Fresno Co. APCD (now the San Joaquin Valley Unified APCD) (559) 230-6000	**NOx** (Detailed Control Information) Johnston burner 40 ppmvd at 3% oxygen 29.4 lbm/day ------------------------------
	3/17/89	**NOx**

Delano Growers Grape Products 32 MMBtu/hr RF MacDonald boiler fired on residual oil (Detailed Information)	(A/C no. 3046004A) A310-337-89 District Contact: Tom Goff Kern Co. APCD (now the San Joaquin Valley Unified APCD) (805) 862-5200	(Detailed Control Information) Low-NOx burner, flue gas recirculation and automatic oxygen trim 10.6 lbm/hr (Equivalent to 20% control or 0.33 lbm/ MMBtu) ----------------------------
California Dept. of Corrections Corcoran Prison Cogeneration Facility 27.4 MMBtu/hr gas-fired Cleaver Brooks Model D-42E with model 200 type BR-1 burner and producing 23,000 lbm/hr steam (uses fuel oil no. 2 backup) (Detailed Information)	12/18/87 (A/C 8715B) A310-291-88 District Contact: George Heinen Kings Co. APCD (now the San Joaquin Valley Unified APCD) (559) 230-5909	**NOx** (Detailed Control Information) Flue gas recirculation 40 ppmvd at 3% oxygen while firing on natural gas (Equivalent to 0.048 lbm/MMBtu); 95 ppmvd at 3% oxygen while firing on fuel oil no. 2 (Equivalent to 0.13 lbm/MMBtu) ---------------------------- **SOx** (Detailed Control Information) Low-sulfur fuel at 0.12% sulfur content 66.6 ppmvd at 3% oxygen (Equivalent to 0.125 lbm/MMBtu) ----------------------------
Ventura Coastal Corp. 31.4 MMBtu/hr Cleaver Brooks model CB-400 boiler fired on natural gas (Detailed Information)	8/31/87 (A/C no. 278-4) A310-234-87 District Contact: Terri Thomas Ventura Co. APCD (805) 654-2844	**NOx** (Detailed Control Information) 20% flue gas recirculation 30 ppmvd at 3% oxygen ----------------------------
Douglas Aircraft Co. Three 33.5 MMBtu/hr Cleaver Brooks model CB200-800 boilers (Detailed Information)	4/23/87 (App. no. 144594 through 144596) A310-231-87 District Contact: Tran Vo South Coast AQMD (909) 396-2579 tvo@aqmd.gov	**NOx** (Detailed Control Information) Flue gas recirculation and oxygen trim system 35 ppmvd at 3% oxygen (equivalent to 0.042 lbm/MMBtu) 68.0 lbm/day total ----------------------------
OLS Energy-Camarillo Two Babcock & Wilcox FM10-52 31 MMBtu/hr boilers for stand-by service only, fired on on natural gas or oil	2/21/87 (A/C no. 1267-2) A310-170-87 District Contact:	**NOx** (Detailed Control Information) Coen DAF low-NOx burners or equivalent

(Detailed Information)	Keith Duval Ventura Co. APCD (805) 654-2845 Kerby@vcapcd.org	40 ppmvd at 3% oxygen for gas firing ------------------------------
Rockwell Intl. 2 MMBtu/hr (50 hp) gas-fired boiler (Detailed Information)	3/22/85 (A/C no. 1291) A310-104-86 District Contact: Stan Cowen Ventura Co. APCD (805) 654-2458	**NOx** (Detailed Control Information) Low-NOx ceramic burners 0.18 tons/yr ------------------------------

Click here to return the CAPCOA BACT Search Page

BACT Clearinghouse Database Lookup Results

21 Match(s) for Code 17.3

Boilers (Gas Fired) - > 33.55 MMBtu/hr heat input

Project Name & Description	A/C Issue Date & ARB File No.	Pollutant
Darling International Inc. 110 MMBtu/hr natural gas-fired Nebraska water-tube boiler used to provide steam for a rendering plant. Propane use as backup fuel. A 1.5 MMBtu/hr duct burner available to keep stack temp. above 575 F. (Detailed Information)	7/17/90 (A/C No.: 186624) A310-934-00 District Contact: Manny Quizon South Coast AQMD (909) 396-2639 mquizon@aqmd.gov	**NOx** (Detailed Control Information) Coen DAF Lo-NOx burner with flue gas recirculation and an Engelhard selective catalytic reduction catalyst. Ammonia slip is limited to 20 ppmvd @ 3% O2. 9 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) No control. 100 ppmvd @ 3% O2 ------------------------------
University of California Irvine Medical Center 48.6 MMBtu/hr Zurn/Keystone watertube boiler use to provide steam for space and water heating,and for sterilization (Detailed Information)	1/16/92 (A/C No.: 248532) A310-923-00 District Contact: Knut Beruldsen South Coast AQMD (909) 396-3136 kberuldsen@aqmd.gov	**NOx** (Detailed Control Information) Six Alzeta Corporation ceramic fiber radiant low-NOx burners 9 ppmvd @ 3% O2 ------------------------------ **CO** (Detailed Control Information) Six Alzeta Corporation ceramic fiber radiant low-NOx burners 50 ppmvd @ 3% O2 ------------------------------
Fansteel/California Drop Forge 39.9 MMBtu/hr Indeck Power Equipment Company model NS-E-59 water tube natural gas fired boiler used to produce steam to drive seven actuated hammers, one mechanical press, and one hydraulic closed die forging press. (Detailed Information)	8/18/98 (A/C no. 343185) A310-880-99 District Contact: Augustine Agwuenu South Coast AQMD (909) 396-2632 aagwuenu@aqmd.gov	**NOx** (Detailed Control Information) Cannon Technology low temperature oxidation system 5 ppmvd @ 3% O2 (determination recinded as of 11/3/99) ------------------------------ **CO** (Detailed Control Information) Cannon Technology low temperature oxidation system 50 ppmvd @ 3% O2 (Determination

recinded as of 11/3/99)

San Benito Foods Tomato Processing 210 MMBtu/hr natural gas-fired Cleaver Brooks boiler with Todd combustion variflame burner (Detailed Information)	12/14/98 (A/C no. 9610) A370-872-99 District Contact: Eva Goodman Monterey Bay Unified APCD (831) 647-9411 egoodman@mbuapcd.org	**NOx** (Detailed Control Information) or (Performance Information) Low NOx burner and flue gas recirculation 30 ppmvd @ 3% O2 ------------------------------
Pacific Offshore Pipeline Co. Two 45 MMBtu/hr plant-gas fired boilers at an oil-field natural gas (sour) processing plant (Detailed Information)	2/4/97 (A/C no. 9047) A350-744-97 District Contact: Steve Sterner Santa Barbara Co. APCD (805) 961-8886 sterners@sbcapcd.org	**SOx** (Detailed Control Information) Amine-based natural gas Sulfinol sweetening system 24 ppmv total sulfur 6 ppmv hydrgen sulfide ------------------------------
Exxon Company, USA Santa Ynez Unit Project Two 95MMBtu/hr Holman Boiler Works portable boilers producing 75000 lbm/hr steam and fired on pipeline quality gas. Boilers were only allowed to operate 360 hours on or before 3/9/96. (Detailed Information)	2/5/96 (A/C no. ATC-9517) A310-672-96 District Contact: Ray McCaffrey Santa Barbara Co. APCD (805) 961-8826	**NOx** (Detailed Control Information) Flue-gas recirculation, fuel induced recirculation, and steam injection as necessary to meet emission limits 27.0 ppmvd at 3% oxygen 0.033 lbm/MMBtu ------------------------------
Mobile Oil Corporation 292 MMBtu/hr Combustion Engineering Co. model no. 35A14 boiler producing 150,000 lbm steam/hr (Detailed Information)	8/21/92 (App. No.: # 266092) A310-616-93 District Contact: Brian Yeh South Coast AQMD (909) 396-2584 byeh@aqmd.gov	**NOx** (Detailed Control Information) Coen model 35A14 LoNOx gas/oil burner No limit ------------------------------
Helm Concentrates 130 MMBtu/hr gas-fired Cleaver-Brooks model no. DL DH-102 water-tube boiler producing 100,000 lbm steam/hr at a tomato processing factor; propane and butane backup fuels (Detailed Information)	5/1/90 (A/C no. 3040340101) A310-463-90 District Contact: Martin Keast Fresno Co. APCD (now the San Joaquin Valley Unified APCD)	**NOx** (Detailed Control Information) Todd Variflame LoNox burner with flue gas recirculation 30 ppmvd at 3% oxygen ------------------------------

	(559) 230-6000	
Kal Kan Foods, Inc. 78.6 MMBtu/hr gas-fired Babcock and Wilcox Model FM-101 boiler producing 65,000 lbm steam/hr use to provide process steam for a pet food manufacturer (Detailed Information)	7/24/90 (A/C No.: 181183 A310-441-90 District Contact: Ken Matsuda South Coast AQMD (909) 396-2544 kmaysuda@aqmd.gov	**NOx** (Detailed Control Information) Hitachi Babcock selective catalytic reduction. Ammonia slip limited to 20 ppm at 3% O2. 9 ppmvd at 3% oxygen ---------------------------- **CO** (Detailed Control Information) Hitachi Babcock selective catalytic reduction 400 ppmvd at 3% oxygen ----------------------------
Darling Delaware 110 MMBtu/hr Nebraska boiler producing 80,000 lbm/hr of steam--fired on nat. gas or propane (Detailed Information)	3/1/90 (App. no. 186624) A310-432-90 District Contact: Rob Castro South Coast AQMD (909) 396-2552 rcastro@aqmd.gov	**NOx** (Detailed Control Information) Selective catalytic reduction 9 ppmvd at 3% oxygen ----------------------------
Toma-Tek, Inc. Gas-fired 90 MMBtu/hr Cleaver-Brooks water-tube boiler with Fuel Tech/Todd dyna-swirl burner producing 75,000 lbm/hr steam (operation limited to July thru Sept.) (Detailed Information)	3/1/89 (A/C no. 3040240103) A310-431-90 District Contact: Martin Keast Fresno Co. APCD (now the San Joaquin Valley Unified APCD) (209) 445-3239	**NOx** (Detailed Control Information) Low-NOx burners and flue gas recirculation 30 ppmvd at 3% oxygen; 3.05 lbm/hr ----------------------------
Westinghouse Electric Corporation 380 MMBtu/hr gas-fired steam generator producing 300,000 lbm steam/hr (Detailed Information)	8/17/88 (A/C no. 883) A310-297-88 District Contact: Hari Doss Bay Area AQMD (415) 771-6000	**NOx** (Detailed Control Information) Low-NOx burners, flue gas recirculation, and SCR 12 ppmvd at 3% oxygen ----------------------------
	8/9/88	

SMUD/Campbell Soup Four 100 MMBtu/hr gas-fired boilers producing 100,000 lbm steam/hr/unit (make and model unspecified) (Detailed Information)	(A/C no. 8577 through 8584) A310-295-88 District Contact: Bruce Nixon Sacramento Metropolitan AQMD (916) 386-6650	**NOx** (Detailed Control Information) Low-NOx burners and flue gas recirculation 40 ppmvd at 3% oxygen ------------------------------
California Dept. of Corrections Corcoran Prison Cogeneration Facility 43.9 MMBtu/hr gas-fired Cleaver Brooks Model D-60E with model 200 type CN-2 burner and producing 37,000 lbm/hr steam (uses fuel oil no. 2 backup) (Detailed Information)	12/18/87 (A/C no. 8715A) A310-290-88 District Contact: George Heinen Kings Co. APCD (now the San Joaquin Valley Unified APCD) (559) 230-5909	**NOx** (Detailed Control Information) Flue gas recirculation 40 ppmvd at 3% oxygen while natural gas (Equivalent to 0.048 lbm/MMBtu); 95 ppmvd at 3% oxygen while firing on fuel oil no. 2 (Equivalent to 0.13 lbm/MMBtu) ------------------------------ **SOx** (Detailed Control Information) Low-sulfur fuel at 0.12% sulfur content 66.6 ppmvd at 3% oxygen (Equivalent to 0.125 lbm/MMBtu) ------------------------------
Cogeneration National Corporation 79 MMBtu/hr water-tube boiler fired on natural gas and fuel oil no. 2 producing 60,000 lbm/hr steam (Detailed Information)	2/25/88 (A/C no. 87-97) A310-272-88 District Contact: George Heinen San Joaquin Valley Unified APCD (559) 230-5909	**NOx** (Detailed Control Information) Low NOx burner and flue gas recirculation 0.073 lbm/MMBtu 50% control on natural gas; 0.106 lbm/MMBtu 51% control on fuel oil no. 2 ------------------------------ **SOx** (Detailed Control Information) 0.20% sulfur content maximum for fuel oil no. 2 0.216 lbm/MMBtu 409 lbm/day on fuel oil no. 2 ------------------------------
	3/2/88	**NOx** (Detailed Control Information) Staged combustion low NOx burner Natural Gas 0.12 lbm/MMBtu 20% control Fuel Oil No. 2 0.16 lbm/MMBtu 56% control

Corn Products 178 MMBtu/hr Zurn Industries 22m Keystone auxiliary boiler fired on natural gas and fuel oil no. 2 producing 150,000 lbm/hr steam (Detailed Information)	(A/C no. 87-141) A310-271-88 District Contact: George Heinen San Joaquin Valley Unified APCD) (559) 230-5909	------------------------------ **SOx** (Detailed Control Information) 0.20% sulfur content maximum for fuel oil no. 2 0.21 lbm/MMBtu 36.9 lbm/hr ------------------------------ **VOC/HC** (Detailed Control Information) Control fuel input Natural Gas 0.04 lbm/MMBtu; Fuel Oil No. 2 0.05 lbm/MMBtu ------------------------------
Basic American Foods Energy-Amer.I Cogeneration Project Two 150 MMBtu/hr Nebraska Boiler Co. model NS-F-85 water-tube boilers fired on natural gas with fuel oil no. 2 standby fuel (Detailed Information)	10/26/87 (A/C no. 4211 and 4212) A310-259-88 District Contact: Fred Thoits Monterey Bay Unified APCD (408) 443-1135	**NOx** (Detailed Control Information) Low NOx burner and flue gas recirculation Limits while firing on natural gas: 40 ppmvd at 3% oxygen 0.048 lbm/MMBtu Limits while firing on fuel oil no. 2: 69 ppmvd at 3% oxygen 0.092 lbm/MMBtu ------------------------------ **SOx** (Detailed Control Information) 0.05% sulfur content maximum for fuel oil no. 2 7.55 lbm/hr ------------------------------ **CO** (Detailed Control Information) Oxidation catalyst 0.018 lbm/MMBtu on natural gas 0.019 lbm/MMBtu on fuel oil no. 2 ------------------------------
McClellan Air Force Base Sacramento, CA 62 MMBtu/hr natural gas-fired boiler (Detailed Information)	10/29/86 (A/C no. 8184 and 8486) A310-169-87 District Contact: Aleta Kennard Sacramento Metropolitan AQMD (916) 386-6650	**NOx** (Detailed Control Information) Low-NOx burner, flue gas recirculation 40 ppmvd at 3% oxygen ------------------------------
	12/19/86	

Naval Station Treasure Island Two 50 MMBtu/hr Cleaver Brooks steam boilers fired on natural gas (Detailed Information)	(A/C no. 30543) A310-167-87 District Contact: Bob Nishimura Bay Area AQMD (415) 771-6000	**NOx** (Detailed Control Information) Flue gas recirculation and low-NOx burners 40 ppmvd at 3% oxygen 0.05 lbm/MMBtu ------------------------------
Folsom Prison Two 48 MMBtu/hr gas-fired boilers (Detailed Information)	6/12/86 (A/C no. 8350, 8351, 8379, and 8380) A310-136-86 District Contact: Aleta Kennard Sacramento Metropolitan AQMD (916) 386-6650	**NOx** (Detailed Control Information) Flue gas recirculation 40 ppm at 3% oxygen ------------------------------
Snack Foods Plant 72 MMBtu/hr fuel oil or natural gas-fired process boiler; 507 gal/hr fuel oil or 72,000 scf/hr for natural gas (Detailed Information)	11/11/83 (A/C # 3082001) A310-014-83 District Contact: Tom Paxson Kern County APCD (Now the San Joaquin Valley Unified APCD) (805) 861-3682	**NOx** (Detailed Control Information) Low NOx burners & low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability 75 ppmv @ 3% O2 6.8 lbm/hr ------------------------------ **SOx** (Detailed Control Information) Low sulfur fuel oil (.25% by weight) to be used only during periods of gaseous fuel unavailability 18.2 lbm/hr ------------------------------ **PM** (Detailed Control Information) Low sulfur fuel oil (0.25% by weight) to be used only during periods of gaseous fuel unavailability 1 lb/hr ------------------------------

Click here to return the CAPCOA BACT Search Page

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Section I: AQMD BACT Determinations
Application No.: 352348
Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 12/6/1999

A. MANUFACTURER: Scotch Marine	
B. TYPE: fire tube type	C. MODEL: Custom
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: 1146	
F. COST: $250,000 (1999)	SOURCE OF COST DATA: Manufacturer/Supplier
G. OPERATING SCHEDULE: 24 HRS/DAY	6 DAYS/WK 52 WKS/YR

2. EQUIPMENT INFORMATION

APP. NO.: 352348

A. FUNCTION: To provide steam for sanitation	
B. MAXIMUM HEAT INPUT: 31.5 MMBtu	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Coen, Micro-Pak
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL: NONE
G. OPERATING CONDITIONS: relatively steady-state and 60% average load	

3. COMPANY INFORMATION

APP. NO.: 352348

A. NAME: Coca Cola	
B. ADDRESS: 11536 Patton Rd CITY: Downey	STATE: CA ZIP: 90241
C. CONTACT PERSON: Viji Sadasivan	D. PHONE NO.: 949 756-3160

4. PERMIT INFORMATION

APP. NO.: 352348

A. AGENCY: SCAQMD		
B. AGENCY CONTACT PERSON: Doug Gordon		C. PHONE NO.: 909 396-2683
D. PERMIT TO CONSTRUCT INFORMATION:	P/C NO.: 352348	ISSUANCE DATE: 11/23/1999
E. START-UP DATE: April 2000		
F. PERMIT TO OPERATE INFORMATION:	P/O NO.:	ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: 352348

A. PERMIT	
A1. PERMIT LIMIT:	7 ppm NOx @ 3% O2, 50 ppm CO @ 3% O2, 5 ppm NH3 @ 3% O2
A2. BACT/LAER DETERMINATION:	See above limits
B. CONTROL TECHNOLOGY	
B1. MANUFACTURER/SUPPLIER:	Peerless Mfg. Co.
B2. TYPE:	Selective Catalytic Reduction System

5. EMISSION INFORMATION

APP. NO.: 352348

B3. DESCRIPTION: The NOx emissions will be controlled by a SCR system

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 359636 ISSUANCE DATE: 11/23/1999
P/O NO.: ISSUANCE DATE:

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE: 27,500 lbs/hr per SCR
ACTUAL CONTAMINANT LOADING: BLOWER HP: 30 HP

B6. WARRANTY: Guaranteed to contol NOx emissions to 7 ppm (SCR) and CO emissions to 50 ppm (low-NOx burner)

B7. PRIMARY POLLUTANTS: NOx and CO

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT:

B10. LIMITATIONS:

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY: TOSCO Refining Company
CONTACT PERSON: Miles Heller PHONE NO.: (310) 952-6120
AGENCY: SCAQMD
ADDRESS: Diamond Bar, CA
CONTACT PERSON: Ngoc Tran PHONE NO.: (909) 396-2606

B12. OPERATING HISTORY:

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: Pending CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

C. COST

C1. CONTROL EQUIPMENT COST: ☒ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST
CAPITAL: $150,000 INSTALLATION: $ (1999) SOURCE OF COST DATA: Manuf./Supplier

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $15,000 (1999) SOURCE OF COST DATA: Manuf./Supplier

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:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

D5. FREQUENCY OF MAINTENANCE:

6. COMMENTS

APP. NO.: 352348

Along with this application, the applicant submitted an additional application (A/N 352349) for an identical boiler at the same location.

Staff has also received a request to further explain the transfer of technology from the previous demonstration example noted in Section 5, Item B11. This information will be added to this BACT listing in the near future.

Section I: AQMD BACT Determinations
Application No.: 366569
Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 8/17/2000

A. MANUFACTURER: Cleaver Brooks	
B. TYPE: Firetube	C. MODEL: CB-LE 500
D. STYLE: N/A	
E. APPLICABLE AQMD REGULATION XI RULES: 1146	
F. COST: $ (2000)	SOURCE OF COST DATA:
G. OPERATING SCHEDULE: 24 HRS/DAY 5 DAYS/WK 52 WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 366569

A. FUNCTION: provide steam for cardboard manufacturing	
B. MAXIMUM HEAT INPUT: 21,000,000 Btu/hour	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: CB-LE
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL: N/A
G. OPERATING CONDITIONS:	

3. COMPANY INFORMATION

APP. NO.: 366569

A. NAME: Lacorr Packaging		B. SIC CODE: 6252
C. ADDRESS: 13890 Nelson Ave. CITY: Industry	STATE: CA	ZIP: 91746
D. CONTACT PERSON: Don Maples		E. PHONE NO.:

4. PERMIT INFORMATION

APP. NO.: 366569

A. AGENCY: SCAQMD	B. APPLICATION TYPE: new construction	
C. AGENCY CONTACT PERSON: Ed O'Neal	D. PHONE NO.: (909) 396-2565	
E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: ☐ CHECK IF NO P/C	P/C NO.: 366569 P/O NO.: PENDING	ISSUANCE DATE: 7/12/2000 ISSUANCE DATE:
F. START-UP DATE: October 2000 (est.)		

5. EMISSION INFORMATION

APP. NO.: 366569

A. PERMIT

A1. PERMIT LIMIT:	NOx = 7 ppmv, dry, corrected to 3% O2, 15-consecutive-min. averaging time NH3 = 5 ppmv, dry, corrected to 3% O2, 15-consecutive-min. averaging time
A2. BACT/LAER DETERMINATION:	see above permit limits
A3. BASIS OF THE BACT/LAER DETERMINATION:	The NOx and NH3 BACT requirements are the same as for the previous BACT listing for Coca-Cola Company (A/N 352348).

5. EMISSION INFORMATION

APP. NO.: 366569

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Peerless

B2. TYPE: SCR

B3. DESCRIPTION: See A/N 341340 (BACT determination for Heater - Refinery)

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 366570 ISSUANCE DATE: 7/12/2000
P/O NO.: pending ISSUANCE DATE:

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

B6. WARRANTY: 3 year

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, SOx, PM10

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY:

B13. UNUSED B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☒ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $150,000 INSTALLATION: $ (2000) SOURCE OF COST DATA: Supplier

C2. ANNUAL OPERATING COST: $~500 (2000) SOURCE OF COST DATA: Supplier

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:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

D5. MAINTENANCE REQUIREMENTS: D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
SOURCE TEST/PERFORMANCE DATA:
OPERATING CONDITIONS:
TEST METHODS:

6. COMMENTS

APP. NO.: 366569

Section I: AQMD BACT Determinations

Application No.: 364408

Equipment Category – Boiler - Portable

1. GENERAL INFORMATION

DATE: 3/15/2000

A. MANUFACTURER: Donlee	
B. TYPE: portable water tube type	C. MODEL: 582-SAHF-650-N
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: 1146	
F. COST: $135,000 (boiler = 60K, burner = 40K, and gas train/burner controls/trim = 35K) (2000) SOURCE OF COST DATA: Owner/Operator	
G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 52 WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 364408

A. FUNCTION: the boiler will be used as an emergency rental unit to provide hot water and steam	
B. MAXIMUM HEAT INPUT: 28.8 MMbtu/hr	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Low-NOx burner
E. PRIMARY FUEL: natural gas	F. OTHER FUEL: LPG
G. OPERATING CONDITIONS:	

3. COMPANY INFORMATION

APP. NO.: 364408

A. NAME: Nation Wide Boiler	
B. ADDRESS: 142400 Christy Street CITY: Fremont STATE: CA ZIP: 94538	
C. CONTACT PERSON: Holy Lepo	D. PHONE NO.: 510-490-7100

4. PERMIT INFORMATION

APP. NO.: 364408

A. AGENCY: SCAQMD		
B. AGENCY CONTACT PERSON: Roy Olivares		C. PHONE NO.: 909-393-2208
D. PERMIT TO CONSTRUCT INFORMATION:	P/C NO.: 364408	ISSUANCE DATE: 3/15/2000
E. START-UP DATE: May 2000		
F. PERMIT TO OPERATE INFORMATION:	P/O NO.:	ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: 364408

A. PERMIT

A1. PERMIT LIMIT: permit limits are the same for each fuel

NOx = 9 ppmv, dry basis, corrected to 3% O2

CO = 50 ppmv, dry basis, corrected to 3% O2

A2. BACT/LAER DETERMINATION: see above limits

5. EMISSION INFORMATION

APP. NO.: 364408

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: ALZETA

B2. TYPE: Low-NOx burner, Alzeta, Model CSB22-SSO-30

B3. DESCRIPTION: The premixed, natural gas fired, radiant burners operate in a flameless mode. These burners achieve low emissions by keeping the combustion temperature below 2000 degress Fahrenheit. Combustion temperature is controlled by varying excess air and surface firing rate.

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: na ISSUANCE DATE:
P/O NO.: na ISSUANCE DATE:

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

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, PM10, and SOx

B8. SECONDARY POLLUTANTS: none

B9. SPACE REQUIREMENT: na

B10. LIMITATIONS: na

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY: UCI Medical Center
CONTACT PERSON: David Mori PHONE NO.: (714) 456-6738
AGENCY: SCAQMD
ADDRESS: 21865 E. Copley Drive
CONTACT PERSON: Knut Beruldsen PHONE NO.: (909) 396-3136

B12. OPERATING HISTORY: none, construction will start 1/2000

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

C. COST

C1. CONTROL EQUIPMENT COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST
CAPITAL: $40,000 INSTALLATION: $ (2000) SOURCE OF COST DATA:

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $ ( ) 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:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

5. EMISSION INFORMATION

APP. NO.: 364408

D5 FREQUENCY OF MAINTENANCE:

6. COMMENTS

APP. NO.: 364408

The boiler will be source tested at three different loads in order to verify compliance with the BACT limits. In addition, the operator is required by permit condition to inspect and maintain the ultra low-NOx burner in accordance with manufacturer's specifications. The boiler will be operated at various locations within the SCAQMD.

This BACT determination is based on the operation of a 48.6 MMbtu/hour boiler with a 9 ppm NOx limit at UCI Medical Center in Orange, California (A/N 248532), equipped with an Alzeta ceramic fiber radiant burner. The unit has been in operation since 1993, and a review of the CEMS data indicates compliance with the 9 ppm permit limit. The proposed boiler will be equipped with a similar burner from Alzeta that is also capable of complying with a 9 ppm limit.

Section I: AQMD BACT Determinations
Application No.: 362566
Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 3/31/2000

A. MANUFACTURER: Cleaver Brooks	
B. TYPE: fire tube	C. MODEL: CB 700
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: 1146	
F. COST: $ ( )	SOURCE OF COST DATA:
G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 52 WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 362566

A. FUNCTION: The boiler will be used to supply steam to heat evaporators and pasteurizing systems.	
B. MAXIMUM HEAT INPUT: 20.9 MMBtu/hour	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Alzeta, ultra-low-NOx burner
E. PRIMARY FUEL: natural gas	F. OTHER FUEL: NONE
G. OPERATING CONDITIONS: load following	

3. COMPANY INFORMATION

APP. NO.: 362566

A. NAME: Hi-Country	
B. ADDRESS: 355 N. joy Street CITY: Corona STATE: CA ZIP: 91720	
C. CONTACT PERSON: Jolene Crosby	D. PHONE NO.: 909-272-2600

4. PERMIT INFORMATION

APP. NO.: 362566

A. AGENCY: `SCAQMD	B. APPLICATION TYPE: new construction
C. AGENCY CONTACT PERSON: Doug Gordon	D. PHONE NO.: 909-396-2683
E. PERMIT TO CONSTRUCT INFORMATION: P/C NO.: ISSUANCE DATE: ☒ CHECK IF NO P/C	
F. START-UP DATE: April 2000	
G. PERMIT TO OPERATE INFORMATION: P/O NO.: F23622	ISSUANCE DATE: 12/16/1999

5. EMISSION INFORMATION

APP. NO.: 362566

A. PERMIT

A1. PERMIT LIMIT:

NOx =< 9 ppmv, dry basis, corrected to 3% oxygen

CO =< 100 ppmv, dry basis, corredcted to 3% oxygen

5. EMISSION INFORMATION

APP. NO.: 362566

A2 BACT/LAER DETERMINATION: above permit limits

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Alzeta

B2. TYPE: Model CSB

B3. DESCRIPTION: The burner is a fully premixed, surface stabilized, natural gas fired burner. Low NOx emissions are achieved by stabilizing a dilute fuel-air mixture on the porous burner surface. Excess combustion air can be varied to achieve different levels of NOx control.

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 362566 ISSUANCE DATE: 12/16/99
P/O NO.: ISSUANCE DATE:

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

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, PM10, SOx

B8. SECONDARY POLLUTANTS: none

B9. SPACE REQUIREMENT:

B10. LIMITATIONS:

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY: UCI Medical Center
CONTACT PERSON: David Mori PHONE NO.: (714) 456-6738
AGENCY: SCAQMD
ADDRESS: 21865 E. Copley Drive
CONTACT PERSON: Knut Beruldsen PHONE NO.: (909) 396-3136

B12. OPERATING HISTORY: The boiler has been operating since April 2000

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

(1) The source test must be conducted by a California Air Resources Board certified lab.

(2) Source tests must be conducted while the boiler is operating at low, average, and high fire using the test methods specified in AQMD Rule 1146(d)(4).

C. COST

C1. CONTROL EQUIPMENT COST: ☒ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST
CAPITAL: $50,000 INSTALLATION: $ ( ) SOURCE OF COST DATA: Supplier

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $ ( ) SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

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

D2. COMPLIANCE DEMONSTRATION:

5. EMISSION INFORMATION

APP. NO.: 362566

D3.	VARIANCE:	NO. OF VARIANCES:	DATES:
	CAUSES:		
D4.	VIOLATION:	NO. OF VIOLATIONS:	DATES:
	CAUSES:		
D5.	FREQUENCY OF MAINTENANCE:		

6. COMMENTS

APP. NO.: 362566

The boiler was relocated from another facility then retrofitted with an Alzeta CSB burner.

Section I: AQMD BACT Determinations

Application No.: 365228

Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 5/17/2000

A. MANUFACTURER: Superior Mohawk	
B. TYPE: fire tube	C. MODEL: 4X-2007-S150
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: Rule 1146	
F. COST: $ ( )	SOURCE OF COST DATA:
G. OPERATING SCHEDULE: HRS/DAY DAYS/WK WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 365228

A. FUNCTION:	
B. MAXIMUM HEAT INPUT: 16.8 MMbtu/hr	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Industrial Combustion
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL:
G. OPERATING CONDITIONS:	

3. COMPANY INFORMATION

APP. NO.: 365228

A. NAME: Bumble Bee Seafoods, Inc.	
B. ADDRESS: 13100 Artic Drive CITY: Santa Fe Springs STATE: CA	ZIP: 90670
C. CONTACT PERSON: Keith Cooper, Maintenance Mgr	D. PHONE NO.: (562) 483-7442

4. PERMIT INFORMATION

APP. NO.: 365228

A. AGENCY: 'SCAQMD'	B. APPLICATION TYPE: new construction
C. AGENCY CONTACT PERSON: Doug Gordon	D. PHONE NO.: (909) 396 - 2683
E. PERMIT TO CONSTRUCT INFORMATION: P/C NO.: 365228 ☐ CHECK IF NO P/C	ISSUANCE DATE: 3/10/2000
F. START-UP DATE: 4/26/2000, estimated completion date	
G. PERMIT TO OPERATE INFORMATION: P/O NO.:	ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: 365228

A. PERMIT	
A1. PERMIT LIMIT: NOx =< 12 ppmv @ 3% O2 and CO =< 50 ppmv @ 3% O2	
A2. BACT/LAER DETERMINATION: Same as the above limits	
B. CONTROL TECHNOLOGY	
B1. MANUFACTURER/SUPPLIER: Industrial Combustion	

5. EMISSION INFORMATION

APP. NO.: 365228

B2. TYPE:

B3. DESCRIPTION: low-NOx burner with flue gas recirculation

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

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

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, PM10, SOx, VOC

B8. SECONDARY POLLUTANTS:

B9. SPACE REQUIREMENT:

B10. LIMITATIONS:

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY: California State Prison at Corcoran
CONTACT PERSON: Pat Downey PHONE NO.: (559) 992-6132
AGENCY: San Joaquin Valley Unified APCD
ADDRESS:
CONTACT PERSON: George Heinen PHONE NO.: (559) 230-6000

B12. OPERATING HISTORY:

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: Within 90 days after initial start-up. Written report of the source test results must be received by August 26, 2000. CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA: Pending

C. COST

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

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $ ( ) SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

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

D2. COMPLIANCE DEMONSTRATION: Pending

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

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

D5. FREQUENCY OF MAINTENANCE: According to the procedures specified by the manufacturer.

6. COMMENTS

APP. NO.: 365228

Boiler shall be source tested at three different loads, maximum, average and low.

Section I: AQMD BACT Determinations
Application No.: 364504
Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 8/29/2000

A. MANUFACTURER: Cleaver Brooks	
B. TYPE: Fire tube	C. MODEL: CB(LE)700-400
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: Rule 1146	
F. COST: $ (2000)	SOURCE OF COST DATA:
G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 52 WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 364504

A. FUNCTION:	
B. MAXIMUM HEAT INPUT: 16.3 mmbtu/hr	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Alzeta Ultra Low NOx
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL:
G. OPERATING CONDITIONS:	

3. COMPANY INFORMATION

APP. NO.: 364504

A. NAME: Liberty Container Co., Key Container	B. SIC CODE: 2650
C. ADDRESS: 4224 Santa Ana Street CITY: South Gate STATE: CA	ZIP: 90280-2557
D. CONTACT PERSON: Bob Felton, Plant Manager	E. PHONE NO.: (323) 564-4211

4. PERMIT INFORMATION

APP. NO.: 364504

A. AGENCY: SCAQMD	B. APPLICATION TYPE: new construction	
C. AGENCY CONTACT PERSON: Ken Matsuda	D. PHONE NO.: (909) 396-2656	
E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: ☐ CHECK IF NO P/C	P/C NO.: 364504 P/O NO.:	ISSUANCE DATE: 3/17/2000 ISSUANCE DATE:
F. START-UP DATE: Approximately October or November 2000		

5. EMISSION INFORMATION

APP. NO.: 364504

A. PERMIT

A1. PERMIT LIMIT: NOx not exceed 12 ppmv and CO not exceed 50 ppmv. Emission limits are referenced at 3% O2 on a dry basis averaged over a period of 15 consecutive minutes. Emissions of NOx not exceed 127 lbs/month, CO not exceed 322 lbs/month

A2. BACT/LAER DETERMINATION:

5. EMISSION INFORMATION

APP. NO.: 364504

A3. BASIS OF THE BACT/LAER DETERMINATION: Determination made based on BACT requirements for other similar boilers listed on SCAQMD BACT webpage (www.aqmd.gov/bact)

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Alzeta

B2. TYPE:

B3. DESCRIPTION: Ultra Low NOx Burner, Model CSB210

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

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

B6. WARRANTY:

B7. PRIMARY POLLUTANTS:

B8. SECONDARY POLLUTANTS:

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY:

B13. UNUSED B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (2000) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (2000) 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:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

D5. MAINTENANCE REQUIREMENTS: D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
SOURCE TEST/PERFORMANCE DATA:
OPERATING CONDITIONS:
TEST METHODS:

6. COMMENTS

APP. NO.: 364504

Section I: AQMD BACT Determinations

Application No.: 363025

Equipment Category - Boiler

1. GENERAL INFORMATION

DATE: 2/2/2000	
A. MANUFACTURER: Cleaver Brooks	
B. TYPE: fire tube type	C. MODEL: CB (LE) 200-400
D. STYLE:	
E. APPLICABLE AQMD REGULATION XI RULES: 1146	
F. COST: $ see comments (1999)	SOURCE OF COST DATA: Supplier
G. OPERATING SCHEDULE: 24 HRS/DAY, 7 DAYS/WK, 52 WKS/YR	

2. EQUIPMENT INFORMATION

APP. NO.: 363025	
A. FUNCTION: hot water and steam	
B. MAXIMUM HEAT INPUT: 16,300,000	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.: 1	TYPE: Cleaver Brooks, Model LE Low NOx Burner
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL: AMBER 363
G. OPERATING CONDITIONS: Load following, with short periods of steady-state operation.	

3. COMPANY INFORMATION

APP. NO.: 363025	
A. NAME: Santa Monica - UCLA Medical Center	
B. ADDRESS: 1250 16th St. CITY: Santa Monica	STATE: CA ZIP: 90404
C. CONTACT PERSON: David Ott	D. PHONE NO.: (310) 825-7076

4. PERMIT INFORMATION

APP. NO.: 363025	
A. AGENCY: 'SCAQMD'	B. APPLICATION TYPE: new construction
C. AGENCY CONTACT PERSON: Sean Cullins	D. PHONE NO.: (909) 396-2655
E. PERMIT TO CONSTRUCT INFORMATION: ☐ CHECK IF NO P/C — P/C NO.: 363025	ISSUANCE DATE: 1/28/2000
F. START-UP DATE: 07/15/2001	
G. PERMIT TO OPERATE INFORMATION: P/O NO.:	ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: 363025

A. PERMIT

A1. PERMIT LIMIT:

Natural Gas operation - 15 ppmvd NOx @ 3% O2, 50 ppmvd CO @ 3% O2.

Amber 363 operation - 40 ppmvd NOx @ 3% O2, 50 ppmvd CO @ 3% O2.

A2. BACT/LAER DETERMINATION: See above permit limits.

5. EMISSION INFORMATION

APP. NO.: 363025

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Cleaver Brooks

B2. TYPE: low-NOx burner with flue gas recirculation

B3. DESCRIPTION:

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: ISSUANCE DATE:
P/O NO.: ISSUANCE DATE:

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

B6. WARRANTY:

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, SOx, and PM10

B8. SECONDARY POLLUTANTS: none

B9. SPACE REQUIREMENT:

B10. LIMITATIONS:

B11. LOCATION OF PRIOR DEMONSTRATION & AGENCY:
FACILITY:
CONTACT PERSON: PHONE NO.:
AGENCY:
ADDRESS:
CONTACT PERSON: PHONE NO.:

B12. OPERATING HISTORY:

B13. SOURCE TEST/PERFORMANCE DATA ANALYSIS:
DATE OF SOURCE TEST: CAPTURE EFFICIENCY:
DESTRUCTION EFFICIENCY: OVERALL EFFICEINCY:
PERFORMANCE DATA:

B14. SOURCE TEST CONDITIONS/PERFORMANCE DATA:

C. COST

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

C2. ANNUAL OPERATIONAL/MAINTENANCE COST: $ ( ) 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:

D4. VIOLATION: NO. OF VIOLATIONS: DATES:
CAUSES:

D5. FREQUENCY OF MAINTENANCE:

6. COMMENTS

APP. NO.: 363025

Along with this application, the applicant submitted two other applications (A/Ns 363026 and 363027) for identical boilers at the same location.

The equipment will be source tested by an independent contractor shortly after start-up to verify compliance with the NOx and CO emissions limits specified in the permit. While operating with natural gas, the equipment will be tested at minimum, average, and maximum loads. While operating with Amber 363 (a low-nitrogen, low-sulfur fuel oil product from Shell Oil), the equipment will be tested at maximum load.

The purchased equipment cost for each boiler (including the low-NOx burner) was approximately $110,000. The installation cost for each boiler was approximately $25,000-$30,000.

This job was engineered when the BACT limit was 20 ppm NOx. Dual-fuel burners are not available in this size range that can meet the 12 ppm NOx limit achieved by other small boilers without dual fuel capability. Therefore, BACT for this particular case was determined to be 15 ppm NOx using a low-NOx burner and FGR.

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AHMerrill & Associates, Inc
Serving Industry Since 1952
Combustion/Pollution Control
2500 Old Crow Canyon Road
Suite 112
San Ramon, CA 94583
(510) 838-7200
(510) 838-1444 FAX

Local Offices:
Laguna Niguel, CA
San Clemente, CA
1-800-8LOW-NOX

April 16, 1997

Ms. Phyllis Fox
2530 Etna Street
Berkeley, CA 94704

SUBJECT: Low NOx Burners

Dear Phyllis:

After reviewing our 61 page low NOx burner installation list, I decided we should segregate the 30 ppm or less units. Once I got a good chance to review our list, I noted there are a lot of units listed because of locality, fuel, etc., exceeding the 30 ppm. In an effort to be clearer, we did pull all the units at 30 ppm or below and have included them in the attached Installation List.

I believe this should be more meaningful and useful to you. Please feel free to call if you have any questions. I will be out of town until Monday, but can return calls.

Sincerely,

Lou Brizzolara

Louis G. Brizzolara

April 15, 1997

COEN COMPANY INCORPORATED
INDUSTRIAL LOW NOx BURNER SALES & INSTALLATION LIST

(Projects listed were sold on or before the above date. Please contact the local Coen Co. representative or Coen Co. for verification of installation and start-up, and for jobsite references. # Jobs not commissioned).

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOx LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
12997-1#	Sherrit International Ft. Saskatchewan, Canada	Cleaver Brooks	(1) 100,000 PPH	Natural Gas	30 PPM	1	CPF/LN-33.5
12986-1#	Oregon Health Sciences Portland, OR	Cleaver Brooks D-60	(1) 40,000 PPH	Natural Gas No. 2 oil	30 PPM 93 PPM	1	QLN 2.6
12966-1#	Air Products Stockton, CA	Zurn 22M	(1) 150,000 PPH	Natural Gas	30 PPM	1	DAF-36
12927-1#	LA Dept of Water Wilmington, CA	Murray MCF4-51	(1) 39.5	Natural Gas	25 PPM	1	QLN 2.2
12877-1#	Rhone Poulenc Carson, CA	Zurn O type	(1) 30,000 PPH	Natural Gas	30 PPM	1	QLN 2.4
12850-1#	General Mills Lodi, CA	Trane MCF2-50	(1) 40,000 PPH	Natural Gas	30 PPM	1	QLN 2.6
12847-1#	Nationwide Boiler Fremont, CA	B&W FM10-61	(2) 45,000 PPH	Natural Gas No. 2 oil No. 6 oil	30 PPM	1	CPF/LN21.5
12845-1#	Oregon Health Oregon	Cleaver Brooks DL-68	(1) 60,000 PPH	Natural Gas No. 2 oil	30 PPM	1	QLN 3.0
12792-1#	Green Bay Packaging Morrilton, AR	ABCO D type	(1) 150,000 PPH	Natural Gas No. 6 oil	~~25 PPM~~ wrong 71.6 PPM 0.10	1	DAF-36
12753-2#	San Francisco Thermal San Francisco, CA	Keeler DK10-15	(1) 55,000 PPH	Natural Gas No.2 oil	30 PPM 150 PPM	1	QLN 3.0
12753-1#	San Francisco Thermal San Francisco, CA	Keeler DK10-15	(1) 55,000 PPH	Natural Gas No.2 oil	30 PPM 150 PPM	1	QLN 3.0
12727-1	NASA/Ames Research Moffett Field, CA	B&W Marine Boiler	(1) 206,000 PPH	Natural Gas	30 PPM	6	QL 2.6 W/FGR
12715-1#	South Dakota Soybean Volga, SD	Nebraska NS-C-58 Econ	(2) 50,000 PPH	Natural Gas No.2 oil	.035 LBS/MMBTU .130 LBS/MMBTU	1	QLN 2.8
12714-1	Univ. of California Davis, CA	B&W FM103-97	(2) 100,000 PPH	Natural Gas No. 2 oil	30 PPM 40 PPM	1	QLN 3.8 W/FGR

April 15, 1997

COEN COMPANY INCORPORATED
INDUSTRIAL LOW NOx BURNER SALES & INSTALLATION LIST

(Projects listed were sold on or before the above date. Please contact the local Coen Co. representative or Coen Co. for verification of installation and start-up, and for jobsite references. # Jobs not commissioned).

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOx LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
12699-1	St. Mary's Hospital San Francisco, CA	B&W FM9-43	(1) 23,000 PPH	Natural Gas No. 2 oil	30 PPM 150 PPM	1	QLN 2.0
12694-1	Romic Chemical Palo Alto, CA	Keeler DS10-B	(1) 40,000 PPH	Natural Gas	30 PPM	1	CPF/LN-21.5 W/FGR
12685-1	San Francisco Int'l San Francisco, CA	IBW TJW-C-25	(2) 25 MMBTU/HR	Natural Gas No. 2 oil	30 PPM 150 PPM	1	DAF-20 W/FGR
12674-1#	J.R. Carey Williamsport, PA	B&W FM0-66	(1) 70,000 PPH	Natural Gas No. 2 oil	30 PPM 70 PPM	1	CPF/LN-30
12647-1#	Tory Plastics No. Kingston, RI	Nebraska NS-E-68	(1) 80,000 PPH	Natural Gas No.2 oil	.034 LBS/MMBTU .076 LBS/MMBTU	1	CPF/LN-30 W/FGR
12636-1	Calif. Pacific Medical San Francisco, CA	Erie City VC	(2) 20,000 PPH	Natural Gas No. 2 oil	30 PPM 150 PPM	1	QLN 2.0
12591-1	Westinghouse Sunnyvale, CA	Wickes 75-5K-4H	(1) 100,000 PPH	Natural Gas	30 PPM	1	QLN-3.0 W/FGR
12590-1	California Paperboard So. San Francisco, CA	B&W FM10-79B	(1) 65,000 PPH	Natural Gas	30 PPM	1	QLN-3.2
12588-2	E.I. DuPont Antioch, CA	Cleaver Brooks DL-68	(1) 50,000 PPH	Natural Gas	30 PPM	1	QLN-2.8
12588-1	E.I. DuPont Antioch, CA	Wicks 590.3KB	(1) 71,500 PPH	Natural Gas	30 PPM	1	QLN-3.2 W/FGR
12579-1#	Nationwide Boiler Fremont, CA	B&W 9-57	(1) 40,000 PPH	Natural Gas No. 2 oil	30 PPM	1	QLN 2.6
12560-1#	Procter & Gamble Sacramento, CA	Foster Wheeler Dow Therm Heater	(1) 32,000 PPH	Natural Gas No .2 oil	30 PPM	1	QLN-2.4
12552-1#	Nationwide Fremont, GA	Nebraska NOS-2-52SP	(1) 60,000 PPH	Natural Gas	9 PPM	1	QL-2.8
12524-1	California Oil Richmond, CA	Cleaver Brooks DLD 68-E	(1) 50,000 PPH	Natural Gas	30 PPM	1	QLN 2.8
12521-1	Topeka State Hospital Topeka, KS	Nebraska NS-B/S-46	(1) 29,000 PPH	Natural Gas No. 2 oil	30 PPM 50 PPM	1	CPF/LN-19

April 15, 1997

COEN COMPANY INCORPORATED
INDUSTRIAL LOW NOx BURNER SALES & INSTALLATION LIST

(Projects listed were sold on or before the above date. Please contact the local Coen Co. representative or Coen Co. for verification of installation and start-up, and for jobsite references. # Jobs not commissioned).

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOx LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
12498-1	Rexham Graphics S. Hadley, MA	B&W FM10-79B	(1) 60,000 PPH	Natural Gas No. 6 oil	30 PPM .32 LBS/MMBTU	1	QLN 3.0 W/FGR
12464-1	Los Gatos Tomato Huron, CA	B&W FM117-97	(1) 150,000 PPH	Natural Gas	30 PPM	1	QLN 4.4 W/FGR
12382-1	J.R. Simplot Pocatello, ID	B&W FM10-89	(1) 60,000 PPH	Natural Gas	30 PPM	1	QLN-3.2
12378-2	Container Corp Los Angeles, CA	Riley-UIW MH	(1) 38,000 PPH	Natural Gas	25 PPM	1	QLN-2.4
12378-1	Container Corp Los Angeles, CA	Riley-UIW MH 120 E	(1) 100,000 PPH	Natural Gas	25 PPM	1	QLN-4.0 W/FGR
12351-1#	American Tobacco Chester. VA	B&W	(1) 60,000 PPH	Natural Gas No. 2 oil	7.8 PPM	1	CPF/LN-24 W/FGR
12349-1	Ciba-Geigy Summit, NJ	CE 20A12	(1) 65,000 PPH	Natural Gas No. 6 Oil	.03 LBS/MMBTU	1	DAF-28 W/FGR
12332-1#	UCSF Medical Cntr. San Francisco, CA	Nebraska NS-E-84- Econ-SH	(2) 90,000 PPH	Natural Gas No. 2 oil	25 PPM 50 PPM	1	CPF/LN-32 W/FGR
12331-1	Napa State Hospital Imola, CA	Nebraska NS-C-48	(1) 37,000 PPH	No. 2 oil	30 PPM	1	DAF-22
12308-1	Hunt Wesson Oakdale, CA	B&W FM117-97	(1) 150,000 PPH	Gas	30 PPM	1	QLN-4.6 W/FGR
12300-1	Cargill Salt Newark, CA	Nebraska NSE-48	(1) 50,000 PPH	Natural Gas	30 PPM	1	QLN-2.8
12251-1	California Cedar Stockton, CA	Keeler Watertube	(1) 10 MMBTU/HR	Natural Gas	30 PPM	1	SDAF-10
12232-1	Sun Company Marcus Hook, PA	Nebraska N2S-8/S1-126SH	(1) 210,000 PPH	Natural Gas Refinery Gas	30 PPM	1	DAF-45 W/FGR
12216-1	St. Mary's Hospital San Francisco, CA	B&W FM9-43	(1) 23,000 PPH	No. 2 oil	30 PPM	1	QLN-2.2
12185-1	Dixon Canning Dixon, CA	B&W FM-120-97	(1) 130,000 PPH	Natural Gas	30 PPM	1	DAF-39 W/FGR

April 15, 1997

COEN COMPANY INCORPORATED
INDUSTRIAL LOW NOx BURNER SALES & INSTALLATION LIST

(Projects listed were sold on or before the above date. Please contact the local Coen Co. representative or Coen Co. for verification of installation and start-up, and for jobsite references. # Jobs not commissioned).

JOB NO.	INSTALLATION	TYPE OF BOILER	(NO. OF UNITS) CAPACITY	FUEL TYPE	GUARANTEED AND/OR ACTUAL NOx LEVELS	NO. OF BURNERS/ BOILER	COEN METHOD OF NOX REDUCTION
12178-1	CILCO Pekin, IL	ABB-CE 40A16-48	(1) 185,000 PPH	Natural Gas	30 PPM	1	DAF-45 W/FGR
12177-1	CILCO Pekin, IL	ABB-CE 35A13/48	(1) 175,000 PPH	Natural Gas	30 PPM	1	DAF-42 W/FGR
12161-2	VA Hospital Menlo Park, CA	Nebraska NS-B/S-40	(3) 20,000 PPH	Natural Gas No. 2 oil	30 PPM	1	SDAF-17 W/FGR
12161-1	VA Hospital Palo Alto, CA	Nebraska NS-B/S-61	(3) 35,000 PPH	Natural Gas No. 2 oil	30 PPM	1	CPF/LN-21.5 W/FGR
12154-1#	Contadina Hanford, CA	B&W FM-120-97	(1) 150,000 PPH	Natural Gas Propane	30 PPM	1	DAF-39 W/FGR
12137-1	Mobil Oil Torrance, CA	ABCO D type	(2) 225,000 PPH	Refinery Gas Butane Gas	.036 LBS/MMBTU .037 LBS/MMBTU	2	DAF-36 W/FGR
12136-1#	Sandoz Phar. East Hanover, NJ	B&W FM 106-97	(2) 100,000 PPH	Natural Gas No. 2 oil	~~10/15 PPM~~ 0.047 lb/MMBtu ~~15/20 PPM~~ 0.1	1	DAF-34 W/FGR
12115-1#	Rental Unit	B&W FM 101-88	(1) 75,000 PPH	Natural Gas No. 2 oil	30 PPM 69 PPM	1	CPF/LN-30 W/FGR
12097-2	General Electric Fort Wayne, IN	Zurn 6M	(2) 20,000 PPH	Natural Gas No. 2 oil	30 PPM 54 PPM	1	CPF/LN-15 W/FGR
12097-1	General Electric Fort Wayne, IN	Zurn 10M	(2) 40,000 PPH	Natural Gas No. 2 oil	30 PPM 67 PPM	1	CPF/LN-21.5 W/FGR
12067-1	Exxon Company Benicia, CA	CE 34-VP-14WL	(1) 150,000 PPH	Refinery Gas Natural Gas	25 PPM	1	DAF-42 W/FGR
12025-1	Gordonsville Energy Gordonsville, VA	IBW D type	(1) 15,500 PPH	Natural Gas No. 2 oil	30 PPM	1	SDAF-14
12019-1# 12019-2# 12019-3# 12019-4# 12019-5# 12019-6# 12019-7#	Rancho Los Amigos Downey, CA	Nebraska NS-B-38- Econ	(7) 24,000 PPH	Natural Gas Low Nit. Oil	25 PPM 40 PPM	1	SDAF-17 W/FGR

April 15, 1997

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11988-1	IBM San Jose	B&W/Keeler FM-10-52/DS-40	(2) 36,000 PPH	Natural Gas No. 2 oil	30 PPM	1	CPF/LN-19 W/FGR
11987-1 11987-2	Nationwide Fremont, CA	B&W FM 227-97	(2) 150,000 PPH	Natural Gas No. 2 oil No. 6 oil	30 PPM	1	DAF-36 W/FGR
11954-1	Heublin Wines Madera, CA	Nebraksa NS-F-81- Econ	(2) 100,000 PPH	Natural Gas Propane/Air	30 PPM	1	DAF-32 W/FGR
11923-1	Henkel Corp. Los Angeles, CA	B&W FM10-79B	(1) 60,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-28 W/FGR
11803-1	Texaco Inc. Montebello, CA	B&W FM-D-9-34	(1) 16,000 PPH	Natural Gas Syn Gas	30 PPM	1	DAF-16.5 W/FGR
11778-1	Nationwide Boiler Fremont, CA	B&W FM 117-88C	(2) 120,000 PPH	Natural Gas No. 2 oil No. 6 oil	30 PPM	1	DAF-34 W/FGR
11769-1	PG&E San Francisco, CA	CE	(1) 17.7 MMBTU	Natural Gas No. 2 oil	30 PPM	1	SDAF-17 W/FGR
11747-4	United Airlines San Francisco, CA	B&W	(1) 75,000 PPH	Natural Gas	30 PPM	1	QLN-3.2
11739-1	U.S. Borax Willmington, CA	Nebraska NS-B-35- Econ	(1) 21,500 PPH	Natural Gas	30 PPM	1	DAF-18 W/FGR
11729-1	Douglas Energy Placentia, CA	Zurn	(1) 69,000 PPH	Landfill Gas Natural Gas	18 PPM 30 PPM	1	DAF-30 W/FGR
11715-1	Indeck	Zurn 14M	(1) 65,000 PPH	Natural Gas	30 PPM	1	DAF-30 W/FGR
11632-2	Wayside Honor Rancho Saugus, CA	Keeler DS-10-13	(1) 50,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-26 W/FGR
11632-1	Wayside Honor Rancho Saugus, CA	Keeler DS-10-13	(1) 50,000 PPH	Natural Gas No. 2 oil	30 PPM	1	DAF-26 W/FGR

April 15, 1997

COEN COMPANY INCORPORATED
INDUSTRIAL LOW NOx BURNER SALES & INSTALLATION LIST

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11571-1	GWF Hanford Cogen Hanford, CA	Nebraska NS-E-65- Econ	(1) 68,000 PPH	Natural Gas	30 PPM	1	DAF-38 W/FGR
11496-1	Lunday-Thagard Co. South Gate, CA	B&W FM1061B	(1) 48,000 PPH	Natural Gas No. 2 Oil Propane/Air (0.003% FBN)	39.9 PPM 30 PPM 33 PPM	1	DAF-22 W/FGR
11478-1	Henkel Corporation Los Angeles, CA	B&W FM 1061A	(1) 40,000 PPH	Natural Gas No. 2 Oil (0.001% FBN)	30 PPM 400 PPM	1	DAF-24 W/FGR
11350-1	Monsanto Company	B&W	(1) 25,000 PPH	Natural Gas	0.048 LB/MMBTU	1	DAF-28
11332-2	Orange County Santa Ana, CA	Keeler DS-10-10	(1) 38,000 PPH	Natural Gas No. 2 Oil (0.001% FBN)	0.04 LB/MMBTU 0.05 LB/MMBTU	1	DAF-22 W/FGR
11310-1	Luz Engineering Boron, CA	G.C. Broach Heater	(12) 53.00 MMBTUH	Natural Gas	0.03 LB/MMBTU	1	DAF-30 W/FGR
10940-1	SCM Chemicals Ashtabula, OH	NBC NS-F-77	(1) 100,000 PPH	Natural Gas No. 2 Oil	0.03 LB/MMBTU 0.25 LB/MMBTU (.03% FBN)	1	DAF-34 W/FGR
10867-1	Gangi Bros. Riverbank, CA	NBC NSE-65	(2) 75,000 PPH	Natural Gas	30 PPM	1	DAF-28 W/FGR
10513-1	L.A. County Landfill SPADRA Project	Zurn Keystone	(1) 110 MMBTU	Landfill Gas	24 PPM	1	DAF-36 W/FGR
EXPORT	Nerefco Refinery Rotterdam, Netherlands	Field Erected	(1) 176,000 PPH	Natural Gas Refinery Gas	23 PPM 49 PPM	2	QLN-3.7

COEN

case history CPF/IBM

SITUATION

IBM Corporation in San Jose, California decided to upgrade their existing boiler with a new ***Coen Low NOx CPF-LN*** burner to meet the new emission requirements for the Bay Area Air Quality Management District (BAAQMD). Although BAAQMD does not require compliance to the new standard of 30 ppm NOx and 400 ppm CO until January 1, 1996, IBM decided to be the first large energy user in the local area to comply - a full 2 1/2 years before the deadline.

Name:	IBM Storage Systems Division
Location:	San Jose, California
Boiler:	Babcock & Wilcox, FM10-52
Capacity:	36,000 PPH Steam
Burner:	Coen Model CPF-LN
Fuels:	Natural Gas & #2 oil
Max. NOx:	30 ppm
Max. CO:	400 ppm

SOLUTION

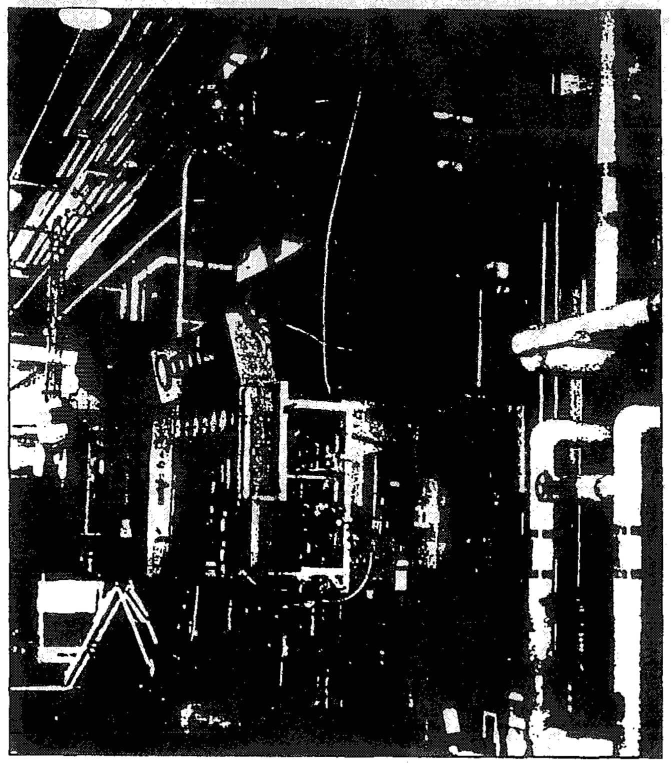
IBM was able to take advantage of existing compatible Coen equipment when converting their boiler to low NOx operation. The existing burner's windbox, fuel piping, and controls were supplied by Coen in 1981 and could be reused in the conversion. The replacement equipment included a new CPF-LN low NOx burner, a larger air fan, and an inlet box to induce flue gas recirculation (FGR).

The entire installation, start-up, and compliance testing of the new equipment was done very smoothly and quickly with minimal impact on the plant's operation. The actual start-up on two fuels was completed in less than one week.

For back-up purposes the burner was designed with gas/oil changeover without shut-down. With either gas or oil fuel, low NOx regulations were met which is very important in a production facility such as this.

RESULTS

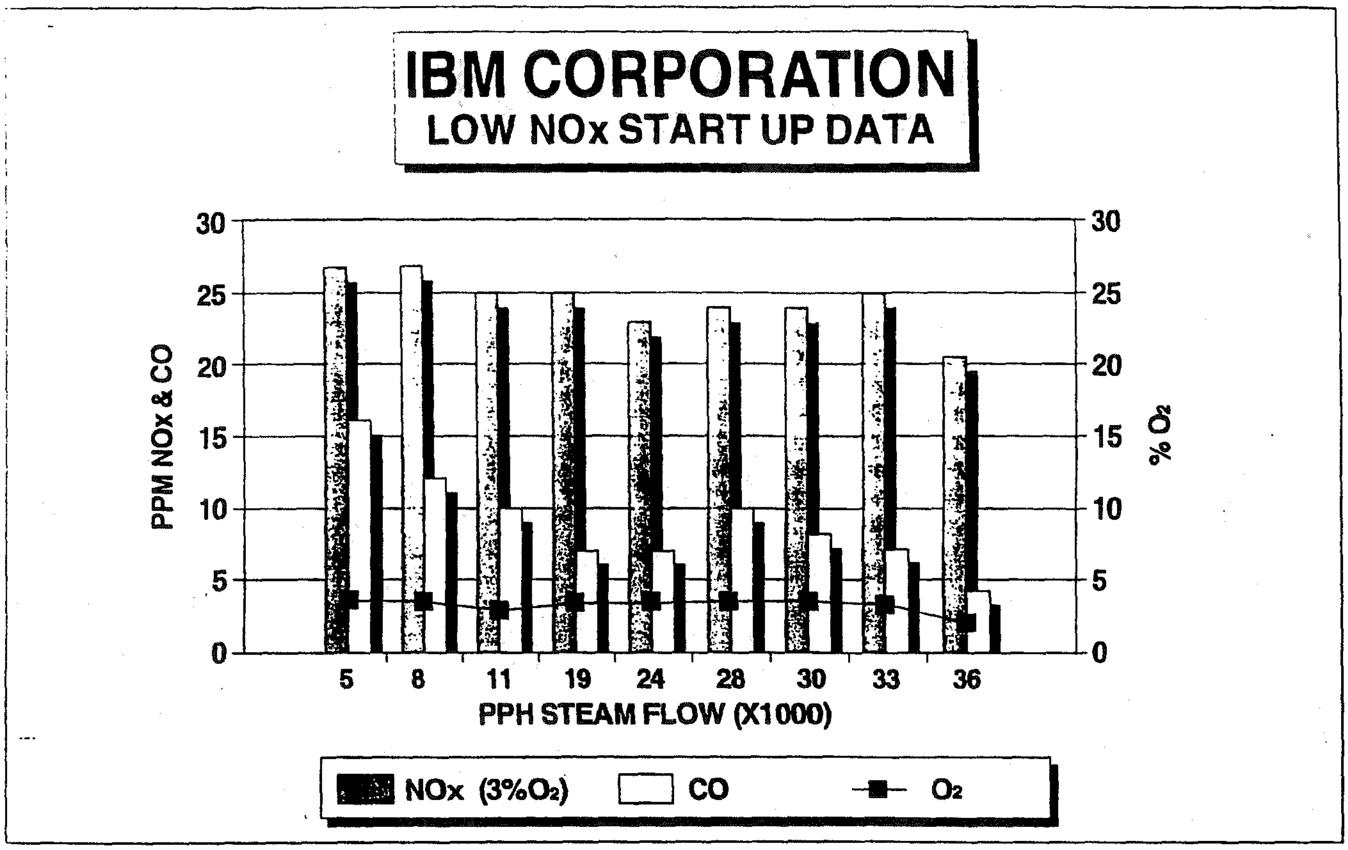
IBM's leadership and sound environmental thinking coupled with Coen's CPF-LN low NOx burner not only met BAAQMD's future regulations, but actually exceeded them by a wide margin. The City of San Jose is fortunate to have such environmentally conscious industries as IBM.



The conversion resulted in:

- ***LOW NOx*** - NOx emissions at full capacity were ***independently tested at 21 ppm***, well below the 30 ppm required by BAAQMD in 1996.
- ***LOW CO*** - Carbon monoxide emissions ***tested at only 4 ppm*** at full load, compared to a 400 ppm requirement.
- ***HIGH EFFICIENCY*** - Low NOx and CO levels were attained with only ***1.7% O_2***.
- ***FLEXIBILITY IN FUEL CHOICE*** - All the requirements of the BAAQMD regulations were met with ***#2 fuel oil as well as gas.***
- ***TURNDOWN*** - Not only did the burner exceed specifications at full capacity, but all BAAQMD regulations were met at ***turndown levels of 10 to 1.***

EMISSIONS	BAAQMD REGULATIONS	ACTUAL
NOx	30 ppm	21 ppm
CO	400 ppm	4 ppm



Low NOx Lessons Learned from IBM Conversion

CUSTOMER NEEDS
- Meet Future Regulations
- Utilize Existing Equipment
- Quick Startup
- Local Supply

OPERATIONS
- High Efficiency
- Low Excess Air
- High Turndown
- Multi-Fuel

AIR QUALITY
- 21 ppm NOx
- 4 ppm CO
- Low Cost per ton of NOx removed

IBM - San Jose Receives ABMA Public Service Award for Energy/Environment Achievement

IBM received ABMA's 1993 award for their environmental awareness and leadership in becoming the first industrial boiler site to conform to the new Bay Area Air Quality Management District (BAAQD) NOx emission regulations. Not only did IBM significantly reduce emissions below required levels but did it 2 1/2 years before the compliance date.

The award states:

> "American Boiler Manufacturers Association PUBLIC SERVICE AWARD FOR ENERGY/ENVIRONMENT presented to IBM CORPORATION OF SAN JOSE, CALIFORNIA for its community oriented, visionary leadership in successfully and immediately addressing and exceeding newly-imposed local industrial emission control regulations well ahead of required compliance."

For additional information on Coen low NOx products and how they can help you meet not only today's emission requirements, but those of the future as well, call or fax:

COEN COMPANY, INC.
Phone: (415) 697-0440 FAX: (415) 579-3255

CPF/IBM 1/94

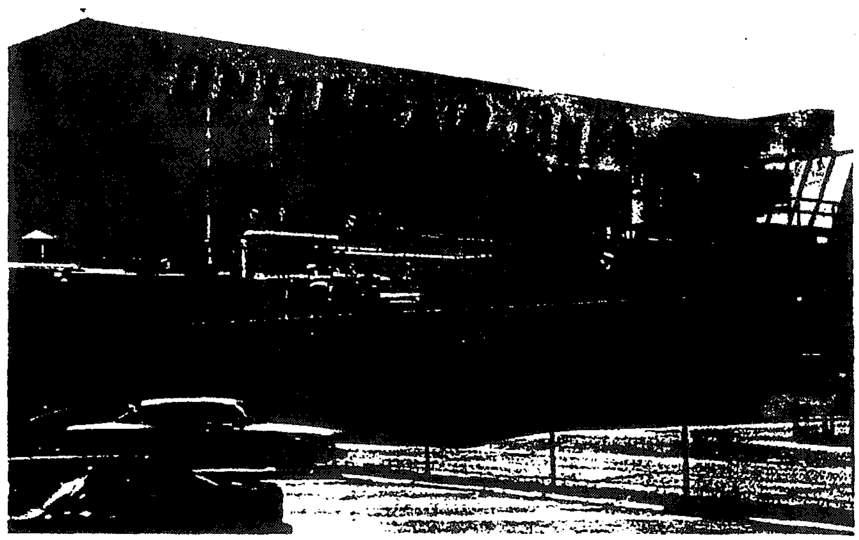
COEN

case history

SITUATION

United Airlines, located at the San Francisco airport, has a cogeneration facility with a 50 MW gas turbine, heat recovery steam generator, and two auxiliary packaged boilers. In order to meet the new Bay Area Air Quality Management District (BAAQMD) emission requirements of 30 ppm NOx and 400 ppm CO on the auxiliary boilers, United decided to retrofit one of their boilers with Coen's new ***Quantum Low NOx "QLN"*** burners a full two years ahead of the January 1, 1996 compliance deadline.

Name:	United Airlines
Location:	San Francisco, California
Boiler:	Babcock & Wilcox, FM
Capacity:	75,000 PPH Steam
New Burner:	Coen Model "QLN"
Fuels:	Natural Gas & #2 Oil
BAAQMD limits:	30 ppm NOx 400 ppm CO



United Airlines 50 MW Cogeneration Facility

SOLUTION

Since the new Coen ***"QLN"*** burner could fit into the existing windbox, the retrofit was accomplished with a minimal amount of rework. The existing windbox, primary air fan, controls, piping and flame safeguard were all reused. One of the benefits of the new ***"QLN"*** burner is that it did not require flue gas recirculation (FGR), so the added expense of a larger fan and motor for FGR with the associated operating horsepower cost and thermal stack losses were avoided, along with the installation and maintenance of an FGR system.

Since the boiler is an auxiliary backup to a gas turbine, a special permit was required to fire with the turbine. Once the local air quality regulators realized the potential NOx reduction of the new burner, they not only helped in our request for a permit, they bent over backwards to see that is was granted.

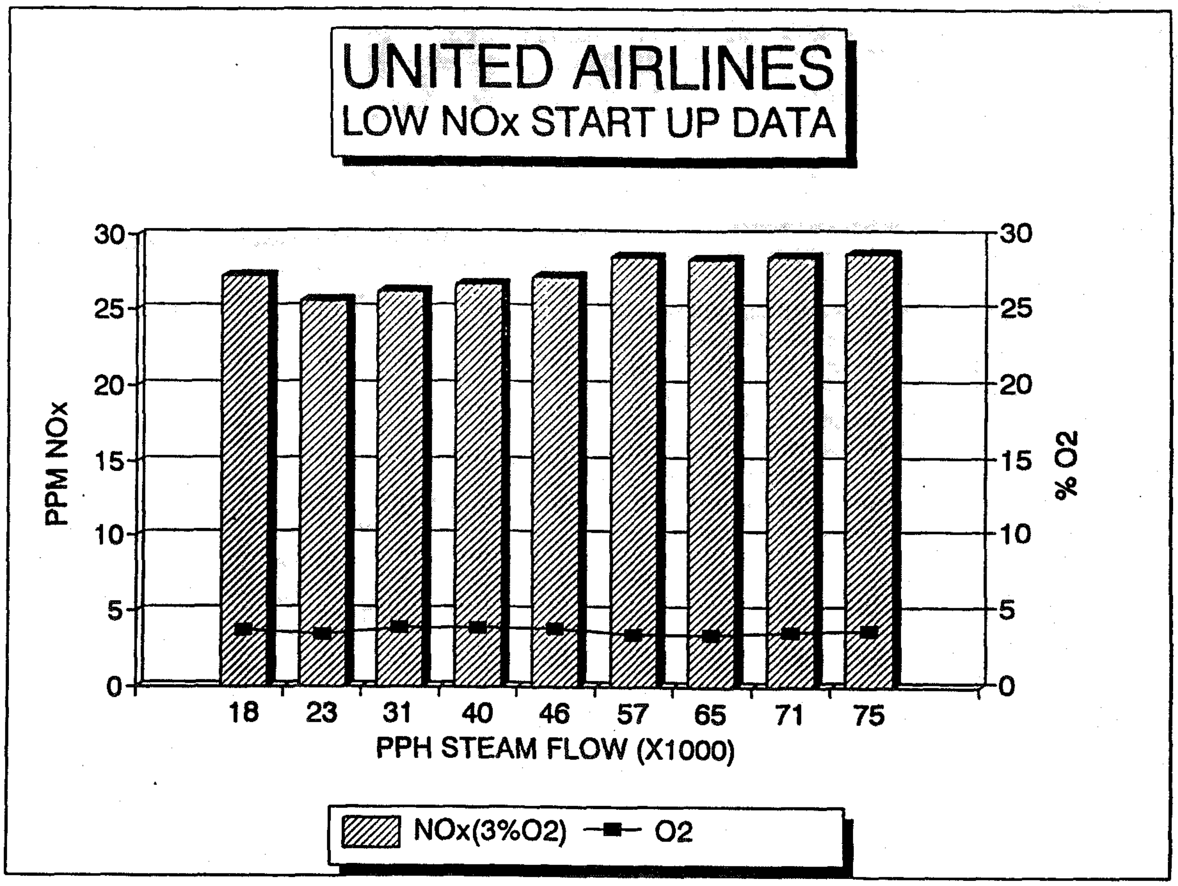
RESULTS

The startup achieved the BAAQMD limits of 30 ppm NOx and 400 ppm CO within two days of firing. No FGR was required and United Airlines met the local regulations a full two years ahead of the compliance deadline.

The conversion resulted in:

- ***LOW NOx*** - At all loads, the BAAQMD permitted limit of ***30 ppm was met without the use of FGR.***
- ***LOW CO*** - Again at all loads, ***the permitted limit of 400 ppm was achieved.***
- ***LOW COST*** - With no FGR fan and motor, United Airlines ***saved on installation, operating cost, and reduced stack losses.***
- ***TURNDOWN*** - The above permitted levels of NOx and CO were met even at a boiler steam flow ***turndown of 10:1.***
- ***EFFICIENCY*** - *The new QLN Burner reduced excess air by 50%.*

COEN COMPANY, INC. 1510 Rollins Road Burlingame, CA 94010 (415) 697-0440 FAX: (415) 579-3255



Low NOx Lessons Learned from United Airlines Conversion

CUSTOMER NEEDS

- Meet Emission Regulations
- Utilized Existing Equipment
- Quick Startup
- Local Supply
- Future Regulatory Ready (FR^2).

OPERATIONS

- No FGR Required
- Low Excess Air
- High Turndown
- Multi-Fuel
- Low operating cost

AIR QUALITY

- 29 ppm NOx
- Low CO
- Low Cost per ton of NOx removed

United Airlines Becomes First Boiler Owner/Operator to Achieve Less Than 30 ppm Without Use of FGR

The United Airlines cogeneration facility had two goals in mind when it decided to purchase the Coen QLN burner. First, to meet the BAAQMD emission requirements of 30 ppm NOx, and second, to avoid the added cost of FGR. United's community oriented, visionary leadership allowed them to meet those goals and comply with local emission regulations a full two years ahead of the compliance date.

For additional information of Coen low NOx products and how they can help you meet not only today's emission requirements, but those of the future as well, call or fax:

COEN COMPANY, INC.
Phone: (415) 697-0440 FAX: (415) 579-3255

QLN/UA 8/94

COEN

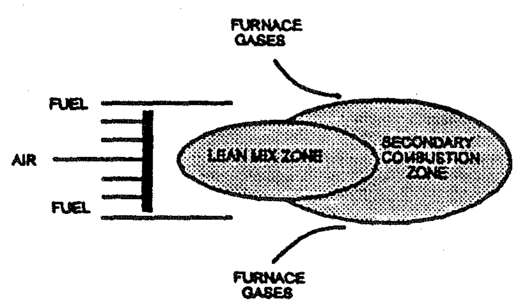
case history QLN/ARCO

SITUATION

ARCO needed to meet the Kern County Air Pollution Control District's (KCAPCD) new emission requirements (Rule 4305) of 30 ppm NOx and 100 ppm CO on their steam flood units. ARCO decided to retrofit one of their steam flood units in Bakersfield, CA with Coen's new Quantum Low NOx "QLN" burner. Because ***existing equipment had high operating cost***, it was desirable to retrofit to a burner that had lower BHP on the primary combustion fan and would meet NOx levels without the use of expensive flue gas recirculation.

Name:	ARCO Western Energy
Location:	Bakersfield, California
Steam Heater:	Natco
Capacity:	62,500,000 Btu/hr
New Burner:	New Coen Model "QLN"
Fuels:	Natural Gas
Limits:	25 ppm NOx; 100 ppm CO

"Quantum Low NOx"



Achieves low NOx performance ..... at lower operating cost

SOLUTION

The new Coen "QLN" burner was delivered as a complete integrated package which easily mounted up to the front of the steamer. ***The existing controls, piping and flame safeguard were reused*** which truly helped make this a low cost conversion. The lower pressure drop of the "QLN" with its efficient fan wheel requires only 30 BHP versus the existing 75 BHP primary air fan motor. ***This will save ARCO thousands of dollars every year.***

Operation and maintenance of the burner is simple. The "QLN" has no moving parts. Once it's adjusted at startup, you can forget it. ***The single point positioning controls are very reliable and interface easily with existing equipment.*** This burner and control package has been proven in numerous installations worldwide.

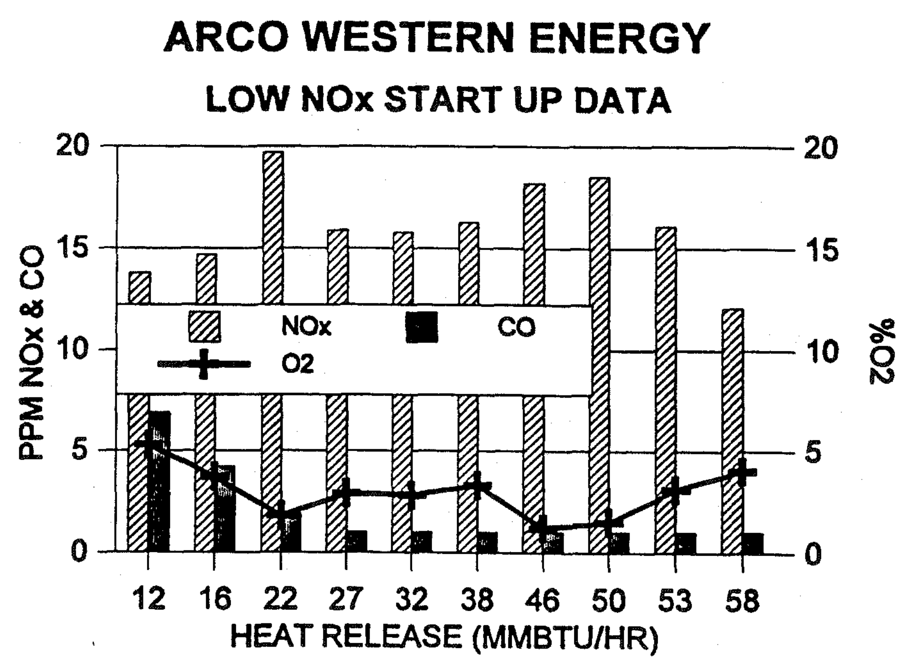
The primary benefit of the new "QLN" burner is that it ***doesn't require flue gas recirculation (FGR).*** The added expense of a larger fan and motor for FGR with the associated operating horsepower cost and loss of thermal efficiency is not necessary. Also, the installation and maintenance of an FGR system is avoided.

RESULTS

The startup results were substantially below the emission guaranteed limits of 25 ppm NOx and 100 ppm CO after only two days of firing. No FGR was required

The conversion resulted in:

- ❒ *LOW NOx -* NOx was less than 20 ppm throughout the firing range and ***only 12 ppm at full load.***
- ❒ *LOW CO -* Again, CO was less than 7 ppm at all firing rates and ***only 1 ppm at high firing rates.***
- ❒ *LOW OPERATING COST -* With no FGR fan and motor and a smaller air fan motor, ***ARCO saved big money*** on installation, operating cost, and increased steamer boiler efficiency.
- ❒ *OFFSETS -* Achieving ***lower NOx numbers than required*** will give ARCO options to expand or increase capacity and be within their plant limit.



LOW NOx LESSONS LEARNED FROM THE ARCO CONVERSION

CUSTOMER NEEDS
- ✔ Met Emission Limits
- ✔ Easy Retrofit
- ✔ Quick Startup
- ✔ Local Supply
- ✔ Quick Startup

OPERATIONS
- ✔ No FGR Required
- ✔ Low Excess Air
- ✔ Low Fan BHP
- ✔ Low Operating Cost
- ✔ High Efficiency

AIR QUALITY
- ✔ < 20 ppm NOx
- ✔ < 7 ppm CO
- ✔ 12 ppm NOx at Full Load
- ✔ Future Lower NOx

Strict Federal air pollution regulations trickling down to the district level are creating great economic challenges to remain competitive in a fierce global environment. It is no longer an option, but a necessity for industry to pursue and implement the latest technology that provides economic and environmental benefits.

Coen Company, producers of combustion equipment for over 80 years, understands this trend. Coen Company is committed to providing the latest in combustion and emission control technology to meet the needs of the oil production, refining and related industries.

QLN/ARCO 5/95

For more information contact:

COEN COMPANY, INC.
1510 Tanforan Ave.
Woodland, CA 95776
Phone: (916) 668 - 2100
Fax: (916) 668 - 2171

A.H. Merrill & Assoc.
2500 Old Crow Canyon Road #112
San Ramon, CA 94583
Phone: (800) 8Low - NOx
Fax: (510) 838 - 1444

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Radian/TODD Rapid Mix Burner (RMB™)
Ultra Low NOx (≤10 ppm) Installations

Operating Installation	OEM	Units x Capacity	Burners per Boiler x Heat Input per Burner	Fuels	Since
Archer Daniels Midland Clinton, IA	CB	2 x 200,000 lbs/hr	2 x 145 MMBtu/hr	Nat. Gas	11/96
Central Plants Century City, CA	FWL	1 x 110,000 lbs/hr	1 x 139 MMBtu/hr	Nat. Gas	01/96
Ciba Geigy Newport, DE	NBC	2 x 100,000 lbs/hr	1 x 122 MMBtu/hr	Nat. Gas, Kerosene	03/97
Consolidated Edison of NY New York, NY	FWL	1 x 150,000 lbs/hr	2 x 88 MMBtu/hr	Nat. Gas, No. 2 Oil	
DeMenno/Kerdoon Compton, CA	CB KW	1 x 800 hp 1 x 1,000 hp	1 x 33 MMBtu/hr 1 x 39.5 MMBtu/hr	Nat. Gas	
Hunt & Wesson Davis, CA	BW	2 x 100,000 lbs/hr	2 x 62 MMBtu/hr	Nat. Gas	06/95
Hunt & Wesson Oakdale, CA	BW BW	1 x 85,000 lbs/hr 1 x 150,000 lbs/hr	2 x 55.5 MMBtu/hr 1 x 196 MMBtu/hr	Nat. Gas	06/96 06/96
Merck & Company Rahway, NJ	ABCO	3 x 70,000 lbs/hr	1 x 100 MMBtu/hr	Nat. Gas, No. 2 Oil	
Monsanto Decatur, AL	CE	1 x 224,000 lbs/hr	1 x 267 MMBtu/hr	Nat. Gas, No. 2 Oil	10/96
Morningstar Packing Los Banos, CA	NBC	1 x 110,000 lbs/hr	1 x 130 MMBtu/hr	Nat. Gas	10/94
Morningstar Packing Williams, CA	NBC	3 x 150,000 lbs/hr	1 x 180 MMBtu/hr	Nat. Gas	07/95
Nationwide Boiler Fremont, CA	NBC	1 x 120,000 lbs/hr	1 x 148 MMBtu/hr	Nat. Gas	
Newark Sierra Paper Board Stockton, CA	BW	2 x 95,000 lbs/hr	1 x 134 MMBtu/hr	Nat. Gas	11/96
N.C. Baptist Hospital* Winston Salem, NC	BW	2 x 60,000 lbs/hr	1 x 73 MMBtu/hr	Nat. Gas, No. 2 Oil	01/96
Pacific Northwest Sugar Moses Lake, WA	NBC	2 x 200,000 lbs/hr	1 x 242 MMBtu/hr	Nat. Gas	

Operating Installation	OEM	Units x Capacity	Burners per Boiler	x Heat Input per Burner	Fuels	Since
~~Rockwell International~~ Downey, CA	~~CB~~	~~2 x 125 hp~~	~~1 x~~	~~5 MMBtu/hr~~	~~Nat. Gas~~	~~07/94~~
Sacremento Municipal Utility District (SMUD) Sacramento, CA	BW	1 x 90,000 lbs/hr	1 x	109 MMBtu/hr	Nat. Gas	
Tri-Valley Growers* Modesto, CA	CB	1 x 120,000 lbs/hr	1 x	144 MMBtu/hr	Nat. Gas	06/96
U.S. Borax Boron, CA	SS	1 x Rotary Dryer	1 x	60 MMBtu/hr	Nat. Gas	07/95
U.S. Borax Wilmington, CA	NBC BWN	1 x 21,500 lbs/hr 1 x Spray Dryer	1 x 1 x	26 MMBtu/hr 20 MMBtu/hr	Nat. Gas	10/94 11/95
Visy Paper Staten Island, NY	NBC	1 x 230,000 lbs/hr	1 x	272 MMBtu/hr	Nat. Gas, No. 2 Oil	03/97
	Total Burners Ordered:		41			

* = No-FGR RMB; 30 ppm NOx guarantee without FGR.

OEM

ABCO = ABCO Industries
BW = Babcock & Wilcox
BWN = Bowen
CB = Cleaver Brooks
CE = Combustion Engineering
FWL = Foster Wheeler
KW = Kewanee
NBC = Nebraska Boiler
SS = Stansteel

(03/97)

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EMISSION PERFORMANCE TESTING OF ONE BOILER

SITE: U. S. BORAX
Wilmington, California

DATE: December 21, 1995

Prepared For:

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1.0 INTRODUCTION

At the request of U.S. Borax, Wilmington, CA, Western Environmental Services (WES) conducted a compliance test on Boiler #7 located in Wilmington California. The testing was conducted on December 21, 1995, to provide compliance test data under rule 1146.1 for the South Coast Air Quality Management District.

The test program consisted of monitoring the stack exhaust for fifteen minutes at three different loads, while firing on natural gas. Oxides of nitrogen, carbon monoxide, and oxygen were monitored during each test. Moisture was measured during mid fire only.

The unit tested is a NS-B-35 W/Economizer, water tube type, 30 MMBTU/HR, natural gas fired boiler. The burners are Radian Rapid mix.

The following sections will be presented in this report: Summary of Results, Site Description, Sampling and Analytical Procedures, Quality Assurance, and Appendices. The appendices contain the Field and Laboratory Data sheets, Calibration Information, and Sample Calculations.

2.0 SUMMARY OF RESULTS

2.1 Discussion of Results

Tables 2.1 through 2.3 show the test data. Tables 2.1 through 2.3 present the continuous monitoring data while tables 2.1a through 2.3a show the CEM corrected data.

The following table summarizes the results of the testing.

Location/Constituent	Test #1 High	Test #2 Mid	Test #3 Low
Water Heater - Natural Gas			
Firing Rate, %	95	46	20
Firing Rate, MMBTU/Hr	28.60	13.87	6.00
Fuel Flow Rate, cfm	454	220	96
FGR % open	25	22	25
Oxides of Nitrogen, ppm	8.36	7.07	6.25
Oxygen, %	3.43	3.70	5.91
Carbon Monoxide, pp	0.20	0.79	81.44
Carbon Dioxide, %	10.25	10.06	8.50
Oxides of Nitrogen(1),ppm*	8.57	7.36	7.47
Carbon Monoxide(1),ppm*	0.20	0.80	97.3
Gas Moisture, %	14.36	14.36	14.36
Flow Rate, DSCFM	4859	2394	1189
Oxides of Nitrogen, lbs/Hr	0.30	0.12	0.054
Carbon Monoxide, lbs/Hr	0.004	0.008	0.43

* NOX (1) & CO (1) - values corrected to 3% oxygen

The results for the boiler show the oxides of nitrogen are below 30 ppm corrected to 3% oxygen and carbon monoxide is below 400 ppm, corrected to 3% oxygen. The results meet SCAQMD Rule 1146.1.

BEST ENVIRONMENTAL, INC. San Leandro, CA 94578 (510) 278 4011

MORNING STAR PACKING CO.

SOURCE EMISSIONS TEST REPORT
Boiler #1

Test Date: December 14, 1994

BEST ENVIRONMENTAL, INC.
15890 Foothill Boulevard
San Leandro, California 94578
(510) 278-4011 FAX (510) 278-4018

December 26, 1994

MORNING STAR PACKING CO.
13448 S. Volta Rd.
P.O. Box 2238
Los Banos, CA 93635

Attn.: Boiler Department

Subject: **Emission test report for one Nebraska boiler located at the Morning Star Packing Co., 13448 S. Volta Rd., Los Banos, CA 93635.**

Test Date: December 14, 1994.

Sampling Location: Sampling was conducted at the outlet of the Nebraska boiler.

Sampling Personnel: Sampling was performed by Russell Gossett and Cliff DeYoung of BEST ENVIRONMENTAL, INC.

Process Description: The natural gas fired boiler is rated at 120 MMBtu/Hr. The boiler is used to supply steam to tomato processing equipment. During our test the boiler was operated at greater than 100% of full fire. Also, two 15 minute runs were performed with the boiler at 55% and 29% of its full load.

Test Program: Triplicate 40 minute tests with calibrations before and after each run were performed on the boiler. During each test, the following continuous monitoring was performed: nitrogen oxides (NOx), carbon monoxide (CO), carbon dioxide (CO_2), and oxygen (O_2). An additional two 15 minute runs were performed with the boiler at different loads. During these runs non-methane hydrocarbons (NMHC) were also monitored. A velocity traverse was performed at the stack outlet of the Nebraska boiler. Since stratification of emission concentrations in the stack was not significant, a representative spot was chosen and the continuous monitoring was conducted at the same location throughout the test program.

Sampling and Analysis Methods: The following California Air Resources Board (CARB) sampling and analytical methods were used:

CARB Method 1-100	NOx, CO_2, O_2, CO, TNMHC
CARB Method 1,2,3,4	Volumetric Flowrate, Moisture, Molecular Weight
EPA Method 19	MMBtu/Hr and DSCFM from Fuel & $\%O_2$

Instrumentation: The following continuous emission analyzers were used:

CO	Thermo Electron 48 Carbon Monoxide Analyzer
NOx	Beckman 951 Chemiluminescent $NO/NO_2/NOx$ Analyzer
CO2	Horiba PIR-2000 Carbon Dioxide Analyzer
O2	Infrared Model 2200 Oxygen Analyzer
THC	Ratfisch RS-55 Hydrocarbon Analyzer

Test Results: Emission results for the Nebraska boiler are presented in Table 1, Table 1A, and Table 2. Table 1 and Table 2 present emissions based on EPA Method 19 calculations. The numbers for these calculations were presented by the control room computer. Table 1A presents emissions based on the volumetric flow rates described in CARB Methods 1-4 .

Stack gas volumetric flowrate and moisture calculations, field data sheets, strip chart records, emission calculations, calibration gas certificates and the PTO's are appended to this report. If you have any questions regarding this report, or if BEST ENVIRONMENTAL, Inc. can be of any further assistance, please call.

Prepared by

Russell Gossett

Russell Gossett
Technician

Reviewed by

Dan Cartner

Dan Cartner
Manager

BEST ENVIRONMENTAL, INC. San Leandro, CA (510)278-4011

TABLE 1
EMISSIONS TEST
MORNING STAR PACKING CO. BOILER NO. 1
Calculations Based on the Fuel Flow

RUN #	1	2	3	Average	Emission
TEST DATE	12-14-94	12-14-94	12-14-94		Limit
TEST LOCATION	OUTLET	OUTLET	OUTLET		SJVUAPCD
TEST TIME	1110-1150	1230-1310	1320-1400		
STEAM RATE, KLbs/Hr	103	103	102	103	
FUEL	Nat. Gas	Nat. Gas	Nat. Gas		
FUEL RATE, KSCFH	123	121	122	122	
FLOWRATE, sdcfm	21,927	21,570	21,749	21,749	
O_2, %	3.20	3.20	3.20	3.20	
CO_2, %	10.0	10.0	10.0	10.0	
NOx, ppm	8.8	8.6	8.5	8.7	
NOx @3% O_2, ppm	8.9	8.7	8.6	8.7	
NOx lbs/MMBtu	0.0108	0.0106	0.0104	0.0106	
NOx, lbs/hr	1.40	1.35	1.34	1.37	
NOx, lbs/day	33.7	32.5	32.2	32.8	90
CO, ppm	< 1.0	< 1.0	< 1.0	< 1.0	
CO @3% O_2, ppm	< 1.0	< 1.0	< 1.0	< 1.0	
CO lbs/MMBtu	< 0.0007	< 0.0007	< 0.0007	< 0.0007	
CO, lbs/hr	< 0.10	< 0.10	< 0.10	< 0.10	
CO, lbs/day	< 2.3	< 2.3	< 2.3	< 2.3	132

WHERE,
- CO = Carbon Monoxide (M.W. = 28)
- NOx = Oxides of Nitrogen (M.W. = 46)
- ppm = Parts Per Million Concentration
- lbs/MMBtu = Pounds per Million Btu Emission Factor
- lbs/hr = Pounds Per Hour Emission Rate
- SDCFM = Standard Dry Cubic Feet Per Minute
- < = Less Than the Detection Limit of the Analyzer

Calculations,
- ppm corr.3% O_2 = (17.9 /(20.9 − %O_2)) x ppm of pollutant
- lbs/MMBtu = 8710 x ppm x (20.9/(20.9 − % O_2)) x 2.59e−9 x Mol. Wt.
- lbs/hr = ppm x SDCFM x 1.58e−7 x Mol. Wt.

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TABLE 1A
EMISSIONS TEST
MORNING STAR PACKING CO. BOILER NO. 1
Calculations Based on the Stack Flow

RUN #	1	2	3	Average	Emission Limit SJVUAPCD
TEST DATE	12-14-94	12-14-94	12-14-94		
TEST LOCATION	OUTLET	OUTLET	OUTLET		
TEST TIME	1110-1150	1230-1310	1320-1400		
FUEL	Nat. Gas	Nat. Gas	Nat. Gas		
FUEL, MMBtu/hr	121	121	121	121	
FLOWRATE, sdcfm	20,722	20,722	20,722	20,722	
H2O, %	16.6	16.6	16.6	16.6	
O2, %	3.20	3.20	3.20	3.20	
CO2, %	10.0	10.0	10.0	10.0	
NOx, ppm	8.8	8.6	8.5	8.7	
NOx @3% O2, ppm	8.9	8.7	8.6	8.7	
NOx lbs/MMBtu	0.0108	0.0106	0.0104	0.0106	
NOx, lbs/hr	1.33	1.30	1.28	1.30	
NOx, lbs/day	31.8	31.2	30.7	31.3	90
CO, ppm	< 1.0	< 1.0	< 1.0	< 1.0	
CO @3% O2, ppm	< 1.0	< 1.0	< 1.0	< 1.0	
CO lbs/MMBtu	< 0.0007	< 0.0007	< 0.0007	< 0.0007	
CO, lbs/hr	< 0.09	< 0.09	< 0.09	< 0.09	
CO, lbs/day	< 2.2	< 2.2	< 2.2	< 2.2	132

WHERE,

CO = Carbon Monoxide (M.W.= 28)
NOx = Oxides of Nitrogen (M.W.= 46)
ppm = Parts Per Million Concentration
lbs/MMBtu = Pounds per Million Btu Emission Factor
lbs/hr = Pounds Per Hour Emission Rate
SDCFM = Standard Dry Cubic Feet Per Minute
< = Less Than the Detection Limit of the Analyzer

Calculations,

ppm corr.3% O2 = (17.9 /(20.9- %O2)) x ppm of pollutant
lbs/MMBtu = 8710 x ppm x (20.9/(20.9-% O2)) x 2.59e-9 x Mol. Wt.
lbs/hr = ppm x SDCFM x 1.58e-7 x Mol. Wt.

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TABLE 2
EMISSIONS TEST
MORNING STAR PACKING CO. BOILER NO. 1
Load Changes

RUN #		1		2	
TEST DATE		12-14-94		12-14-94	Emission
TEST LOCATION		OUTLET		OUTLET	Limit
TEST TIME		1415-1430		1459-1514	SJVUAPCD
LOAD CAPACITY, %		55		29	
FUEL		Nat. Gas		Nat. Gas	
FUEL RATE, KSCFH		64		33	
FLOWRATE, sdcfm		11,540		5,916	
O2, %		3.40		3.30	
CO2, %		9.9		9.9	
NOx, ppm		7.4		8.6	
NOx @3% O2, ppm		7.6		8.7	
NOx lbs/MMBtu		0.0092		0.0106	
NOx, lbs/hr		0.62		0.37	
NOx, lbs/day		14.9		8.9	90
CO, ppm	<	1.0	<	1.0	
CO @3% O2, ppm	<	1.0	<	1.0	
CO lbs/MMBtu	<	0.0008	<	0.0007	
CO, lbs/hr	<	0.05	<	0.03	
CO, lbs/day	<	1.2	<	0.6	132
TNMHC, ppm	<	1.0	<	1.0	
TNMHC @3% O2, ppm	<	0.9	<	0.9	
TNMHC lbs/MMBtu	<	0.0006	<	0.0006	
TNMHC, lbs/hr	<	0.03	<	0.01	
TNMHC, lbs/day	<	0.7	<	0.4	4.2

WHERE,

CO = Carbon Monoxide (M.W.= 28)
NOx = Oxides of Nitrogen (M.W.= 46)
ppm = Parts Per Million Concentration
lbs/MMBtu = Pounds per Million Btu Emission Factor
lbs/hr = Pounds Per Hour Emission Rate
SDCFM = Standard Dry Cubic Feet Per Minute
< = Less Than the Detection Limit of the Analyzer

Calculations,

ppm corr.3% O2 = (17.9 /(20.9− %O2)) x ppm of pollutant
lbs/MMBtu = 8710 x ppm x (20.9/(20.9−% O2)) x 2.59e−9 x Mol. Wt.
lbs/hr = ppm x SDCFM x 1.58e−7 x Mol. Wt.

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FINAL DRAFT

San Joaquin Valley
Air Pollution
Control District

Best Available Control Technology (BACT)
NOx Controls for Natural Gas-fired Boilers, Process Heaters and Steam Generators

June 1, 1999

BACT ANALYSIS: NOx Controls for Natural Gas-Fired Boilers, Process Heaters and Steam Generators.
June 1, 1999

FINAL DRAFT

FINAL DRAFT

I. Background

In the late 1980's the District established the BACT requirement for external combustion devices at 30 ppmv NOX @ 3% O2. At this juncture, in light of compelling new evidence that low NOx technologies have evolved, the District is updating its BACT requirements for boilers.

For nearly 3 years USEPA has objected to District's BACT requirement of 30 ppmv @3% O2. In fact, USEPA has recently initiated or threatened enforcement action against facilities for which the District proposed or issued permits at 30 ppmv. Until recently, the District staff was of the opinion that sufficient field and engineering data did not exist to conclude that the more effective NOx control technologies could reliably achieve the lower NOx levels on an ongoing basis.

The District now has acceptable data on several installations achieving NOx levels well below 30 ppmv. Additionally, a number of applicants have already proposed and installed boilers achieving similarly low NOx levels. See Appendix A for a listing of existing and proposed facilities meeting NOx levels well below 30 ppmv.

This determination has been developed in consultation with burner manufacturers, equipment vendors, facility operators, and oversight agencies. This determination establishes the most effective NOX control after taking into account technical and operational feasibility issues, safety concerns, and economic impacts.

II. Source Categories and Pollutants Covered by this Determination

This BACT determination will cover boilers, steam generators, and process heaters fired on gaseous fuel. Boilers at food processing plants, hospitals, and industrial facilities, oilfield steam generators, and refinery process heaters are examples of sources covered by this BACT determination.

Combustion of natural gas in external combustion devices results in the emission of Particulate Matter (PM), Sulfur Oxides (SOx), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOC) and Carbon Monoxide (CO).

NOx is the most significant air contaminant emitted from gas fired external combustion devices. This determination will establish new BACT levels for NOx.

III. BACT Applicability

District Rule 2201, New and Modified Stationary Source Review (NSR), applies to new and modified sources of air pollution that are subject to the District's permitting requirements. BACT is a key NSR requirement that applies to new or modified sources of air pollution that result in increase in emissions greater than 2 pounds per day. BACT does not apply retroactively to existing sources.

IV. BACT Definition

In conformance with state and federal laws, District Rule 2201 defines BACT as the most stringent emission limitation or control technique from the following options:

- An emission limitations or control technique that has been achieved in practice for such emissions unit and class of source.
- An emission limitations or control technique contained in any State Implementation Plan approved by the Environmental Protection Agency for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the APCO that such limitation or control technique is not presently achievable.
- Any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APCO to be technologically feasible for such class or category of sources or for a specific source, and cost effective as determined by the APCO.

V. BACT Determination Process

BACT determination is an integral part of the permit review process. On a case-by-case basis, for each application, the District must determine the control technology that satisfies the above BACT definition for the particular emissions unit and class of source being proposed. Towards that end, the District performs a five-step top-down analysis that accomplishes the following:

<u>Step 1:</u> Identify all possible control technologies for the emission unit in question.

<u>Step 2:</u> Eliminate controls that are not technologically feasible for the class of source or the particular emission unit being reviewed. To exclude a control option, a demonstration of technical unfeasibility must be clearly documented and should show, based on physical, chemical, and engineering principles, the

technical difficulties would preclude the successful use of the control option for the emissions unit under review.

Step 3: All remaining controls are ranked by their control effectiveness.

Step 4: A cost effectiveness analysis is performed and economic impacts are considered to arrive at the final level of control. The cost effectiveness of each alternative is determined by calculating the cost in dollars per ton of emissions reduced. Control options that are not cost effective, except for controls that have been achieved in practice or are required by an EPA approved SIP, are eliminated from consideration.

Step 5: The most effective control not eliminated under step 4 is selected as BACT.

A detailed description of the District's BACT determination policies and procedures is contained in District Policy BACT-1 (Appendix B).

VI. NOx Formation in External Combustion Devices

NOx is the most significant air contaminant produced when burning natural gas. It is formed either by thermal fixation of nitrogen in the air (thermal NOx) or by the conversion of chemically bound nitrogen in the fuel (fuel NOx).

A. Thermal NO_x: In fossil fuel combustion, O_2 and N_2, from the combustion air, combine to form nitric oxide (NO) and nitrogen dioxide (NO_2) in the high temperature zones in the burner flame. The main factors affecting the quantity of NO_x formed by thermal fixation are the peak flame temperature within the combustion chamber; the residence time of the combustion gases in the peak temperature zone; and the oxygen concentration in the peak temperature combustion-zone . Thermal NOx is the primary NO_x formation mechanism for natural gas fired combustion equipment.

B. Fuel NO_x: In fossil fuel combustion, fuel bound nitrogen can react with O_2 to form NO_x emissions. The rate of NO_x formation due to fuel nitrogen converted is dependent upon the amount of nitrogen contained in the fuel; oxygen concentration present in the flame; and the mixing rate of the fuel and air. Most natural gas contains no fuel bound nitrogen. An exception to this is gaseous fuel with a high ammonia (NH_4) content. This may be encountered in a refinery gas or, less commonly, from biologically formed gas. The nitrogen component provides an increased feedstock for NOx formation compared to commercial grade natural gas.

C. Prompt NO_X: In fossil fuel combustion, NO_X can also form due to the reaction of molecular nitrogen with free radicals such as HCN, NH, and N present in the burner flame. These reactions are not related to the peak flame temperature. Therefore, combustion modifications do not have a strong influence on the NO_X formed by this mechanism.

VII. Overview of NOx Control Technologies

The two primary methods for control of NOx from external combustion devices are to either alter combustion parameters to reduce NOx formation (combustion modification) or to treat the NOx formed before it enters the atmosphere (exhaust gas treatment).

A. Combustion Modification: Combustion modification systems are designed to reduce thermal NOx formation by changing flame characteristics to lower peak flame temperature. Common combustion controls include the following:

1. <u>Low Excess Air Operation :</u> Low excess air operation (LEAO) tightly control the amount of excess combustion air. Such control is usually accomplished through the use of an O_2 analyzer/controller. Operating with low excess air reduces the O_2 concentration in the peak temperature zone, inhibiting the reactions responsible for both thermal and fuel bound NO_X. LEO is generally used in conjunction with other NO_X control techniques.

2. <u>Off-Stoichiometric Combustion (Staged Combustion):</u> Combustion of the fuel is accomplished in two stages. The first stage is a fuel rich zone in the region of the primary flame. The second stage is an air rich zone that completes the combustion of the fuel. Staging the combustion results in lower NO_X emissions by limiting available O_2 for NO_X formation in the fuel rich primary stage; lowering flame temperature in the fuel rich primary stage; and flame temperature is lower in the air rich secondary stage. Common off-stoichiometric combustion systems include:

   - **Overfire Air Ports (OFA):** Additional air injection nozzles are located above the burner to provide supplemental air. The primary burner zone is operated in a fuel-rich condition and the overfire air ports maintain the rest of the combustion zone in a air-rich condition.

   - **Biased Firing:** In boilers with multiple burners, some burners are operated in a fuel-rich condition while other burners are operated in an air-rich condition. Burners are arranged in a staggered configuration so the entire flame field mimics a single staged combustion flame..

- **Burners Out of Service:** In boilers with multiple burners, some burners are operated in a fuel-rich condition while other burners are not fired but provide combustion air only. This arrangement mimics the OFA system.

3. <u>Burner Design:</u> Combustion modification is also achieved by a variety of low-NOx and ultra-low NOx burner designs. Low NO_x burners control mixing of fuel and air in a pattern that keeps flame temperature low and dissipates the heat quickly. Low NO_x burners incorporate many design principles to achieve low NO_x operation. Some low NO_x burners use multiple design principles. The most common design principles are listed below.

- **Staged Air Burners:** Staged air burners operate with a fuel rich primary zone and air rich secondary zone (off-stoichiometric combustion). The fuel rich primary zone reduces the O_2 available for NO_x formation and can lower combustion temperatures in both zones. Staged air burners employ secondary air ports and flame shaping to achieve the desired combustion zones.

- **Staged Fuel Burners:** This is similar to the staged air burners, except that the fuel, rather than the air is added in stages. The first stage is an oxygen-rich, fuel-lean stage in which the peak zone temperature is reduced. The second stage is a fuel-rich, oxygen-lean stage that carries out the combustion. Lower flame temperature reduces the formation of thermal NO_x.

- **Pre-Mix Burners:** Fuel and air are pre-mixed prior to introduction into the burner. Good mixing allows complete combustion to take place with less excess air. Operating with low excess air reduces the O_2 concentration in the peak temperature zone. This inhibits the reactions responsible for both thermal and fuel bound NO_x formation.

- **Internal Recirculation:** Burner geometry induces combustion gases to recirculate in the flame combustion zone. This reduces NO_x formation by reducing the flame temperature and diluting the oxygen content in the peak temperature zone similar to FGR.

- **Radiant Burners:** Radiant burners have an incandescent surface that transfers heat as radiant energy from the burner to the heat exchanger walls. The burner consists of a porous ceramic or metal fiber matrix. Pre-mixed gas and air are forced through the openings in the fiber matrix. Once ignition occurs, combustion stabilizes on the outer surface of the ceramic burner. The burner operates at a lower temperature than conventional burners. The low burner temperature reduces the formation of thermal NO_X.

4. **Flue Gas Recirculation:** Combustion control systems may be used alone or in combination with Flue Gas Recirculation systems (FGR). FGR systems recycle a portion of the exhaust stream back to the burner windbox, mixing low O_2 air with combustion air prior to entering the combustion chamber. This reduces thermal NO_X formation by reducing the peak temperature and by reducing the oxygen in the combustion zone.

   The two types of FGR systems are forced draft and induced draft. Forced draft systems use a separate exhaust gas blower to recirculate the flue gas. Induced draft systems use the primary combustion blower to recirculate the flue gas. In both systems the primary combustion air and the recycled exhaust gas are typically mixed in the windbox.

   As the FGR rate increases, the amount of NO_X produced decreases. In general, manufacturers' specifications of a gas-fired boiler indicate that the use of external FGR, operated at a minimum FGR rate of 20%, is expected to reduce NOx emissions of less than 30 ppmv at 3% O_2, during normal operation. Too high an FGR rate, especially at low firing rates, can cause flame instability which defeats the purpose of flame geometry control.

   Because the FGR gasses physically displace combustion air, boilers with high FGR rates have a more limited fuel gas input and a lower maximum heat output than a comparable boiler with the same air-to-fuel ratio and a lower FGR rate. Also, the FGR gases are often driven by an electrical fan so higher FGR rates translates to higher electrical costs. For these reasons, operators prefer to minimize FGR to the extent allowed by the NOx limits on their operating permit.

B. Exhaust Gas Treatment: Exhaust gas treatment is the second approach to NOx reduction. NO_X can be reduced to molecular nitrogen by adding flue gas treatment systems located after the boiler firebox. The two basic system types are Selective, Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR).

1. Selective Noncatalytic Reduction: For high temperature operations, a reagent, such ammonia (NH_3) or urea ($(NH_2)_2CO$) is injected into the post combustion zone of the boiler. The urea decomposes with heat,

releasing ammonia which serves as a reagent. The reagent reacts with the NO_X formed during combustion to form molecular nitrogen, water, and, when urea is used, carbon dioxide. This reaction is largely dependent upon temperature.

The reaction only occurs at temperatures between 1600° F and 2000° F. At temperatures above 2000° F the nitrogen in the ammonia is oxidized to produce NO_X. At temperatures below 1600° F the ammonia/urea passes through unreacted. Because of the temperature dependence of the reaction, the placement of the ammonia/urea injectors is critical. The optimum injection point changes with boiler load, so most SNCR systems have two sets of injection points. The ratio of the ammonia concentration to the NO_X concentration is an important parameter. Injection of reagent at a higher stoichiometric ratio increases NO_X conversion efficiency but also increases ammonia slip. Ammonia slip is a measure of the amount of emissions of unused ammonia.

2. **Selective Catalytic Reduction:** A catalyst may be used to initiate the same reaction at a typical exhaust temperature range of 400° F to 600° F. In these systems, ammonia is injected through a series of nozzles arranged in a grid to facilitate uniform mixing prior to a catalyst bed. The ammonia reduces the NO_X on the catalyst surface. The operating range for SCR catalysts is typically 550° F to 750° F. Each SCR catalyst has an even narrower temperature window for optimum operation. Variations in exhaust gas temperature of 50° F can have an impact on NO_X reduction efficiency.

There are a variety of problems that can affect catalyst bed performance. Phosphorus, lead and arsenic can irreversibly poison the catalyst material. The catalyst can also be masked by chemicals or particulate adsorbing to the surface. The ratio of the ammonia concentration to the NO_X concentration is critical. Injection of ammonia at a higher stoichiometric ratio increases NO_X conversion efficiency but also increases ammonia slip. The ammonia injection grid must also uniformly mix and atomize the ammonia.

VIII. Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

Possible controls for NOx from natural gas fired equipment include:

Option 1: Ultra-low NOx burners (BACT Level: 9 - 15 ppmv)
- a - Alzeta Radiant Cell Burner
- b - Todd Radian Rapid Mix Burner (RMB)
- c - Coen Quantum Low-NOx (QLN) and Variable Geometry Burners (VGB)

Option 2: Exhaust Gas Treatment Systems (BACT Level ≤ 9 ppmv)
- a - Selective catalytic reduction (SCR) with ammonia or urea injection
- b - Cannon Technology Low Temperature Oxidation

Option 3: Low-NOx burners (BACT Level: 14 - 30 ppmv)

Option 4: Electrical Heaters (Alternative Basic Equipment)

A search of the California Air Resources Board (CARB) BACT database, the EPA RACT/BACT/LAER Clearinghouse, and the South Coast AQMD and Bay Area AQMD Clearinghouses do not indicate any additional technologies other than the above. NOx control technology is fast evolving and research and development is ongoing. Nothing in this determination is meant to imply that possible controls are to be limited to the products listed. Other feasible controls that can achieve equivalent or lower emission levels will be acceptable to the District.

The above specified BACT levels indicate the emission rates that will be accepted as BACT for various applications that can utilize the specified control technology. It is important to note that some of these technologies can be designed and operated at varying control efficiencies. Therefore, identification of BACT must include the required NOx level for each source category.

A. Technology Description

Option 1a: Alzeta Radiant Cell Burner: This system does not have a traditional burner element, but instead uses a cylindrical burner tube(s) made of either a porous ceramic material or a perforated steel tube which supports a metallic mesh burner unit. The gaseous fuel is introduced into the center of the tube where it mixes with combustion air and migrates through the opening in the burner walls. The combustion zone occurs with a small, blue flame field close to the surface of the burner. Thermal NOx formation is minimized by this system because the combustion takes place with a relatively small, cool flame and, on the surface of the ceramic or steel mesh burner. The flame field of the steel burner is also designed to provide internal circulation patterns that enhance complete combustion and prevent hot spots .

The Alzeta radiant heat system appears to offer a stable system with low maintenance at a reasonable cost. Details of actual operating systems is included in Appendix C. Reports of their ceramic-based system indicate a favorable impression from their operators. The manufacturer has switched to a steel burner assembly, which reduces burner size for retrofitting existing boilers where space constrain use of the ceramic unit. The system can be scaled to 180 MMBtu/hr with a single steel burner while the ceramic burner can be sized to 100 MMBtu/hr per burner. Higher ratings would require multiple burners. Burner limitation is based on physical size constraints. Steel requires approximately 1/20th the surface area of ceramic burners for a given heat output.

The Alzeta burner can be operated at 30 ppmv with 30% excess air, 20 ppmv NOx with 40% excess air, and 9 ppmv with 50% excess air (10% oxygen). The 9 ppmv level represents a 5% fuel penalty, compared to the 20 ppmv level, due to the need to heat the additional recirculated air back up to the fuel combustion temperature. Recently, Alzeta added an FGR system to a boiler, which achieved 9 ppmv NOx with 20 - 25% recirculated air and 3% excess air out the stack. Due to the initial cost of the FGR and annual FGR fan operating cost, such systems are more cost effective for larger units. An FGR test was performed on an existing Alzeta burner but the system was removed after testing so no operating Alzeta/FGR units are currently operating.

The turn-down ratio for this technology is approximately 5:1 and it's use is limited to forced draft applications to ensure adequate air/fuel mixing in the burner cylinder. No safety concerns have been expressed about this technology.

Option 1b: Todd/Radian Rapid Mix Burner (RMB): This burner uses a combination of FGR, special ceramic vanes, and gas injectors to rapidly blend the air-fuel mixture and flue gas for properly controlled combustion with minimum thermal NOx formation. The manufacturers guarantee NOx emissions of 9 ppmv within the design operating range. Application is limited to forced draft units to ensure sufficient airflow to facilitate the swirling airstream necessary for proper operation. This technology can be applied to low-temperature applications (e.g. boilers, dryers and process heaters) but not to high temperature applications (e.g. glass melting furnaces). Burners can be scaled for boilers up to 270 MMBtu/hr and dryers up to 60 MMBtu/hr heat input.

Early installations of this system experienced control problems at low fire which caused the flame to be blown out, allowing the unburned fuel to collect in the burner housing. When the system automatically restruck the flame, the unburned fuel would be ignited, resulting in either minor "puffs" or, in one case, in 1996, a boiler explosion. These instances appear to be the result of either operator error or trying to use traditional burner controls with the advanced RMB technology. Current installations (Appendix A) use improved controls which can offer better responsiveness and a broader operating range to avoid flame out conditions. Operator reports indicate that, with the new controls and proper tuning procedures, the earlier safety problems have not reoccurred. The District is convinced that these early developmental problems have been resolved with today's more advanced burner control systems. The ever-improving ability to more accurately control the air-to-fuel mixture at low firing rates has apparently solved this potential safety problem.

It is also important to note that Todd RMB is only one of the technologies capable achieving of single-digit NOx levels and similar safety concerns have not been raised about technologies other than Todd RMB. While the District believes the RMB to have been proven safe when installed and operated properly, the District is not specifically mandating the use of the RMB system and the other options remain available.

Option 1c: Coen Quantum Low-NOx (QLN) and Variable Geometry Burners (VGB): The QLN burner uses fuel-air premixing and staged combustion to improve combustion and reduce thermal NOx formation. Current applications include mid-size boilers and steam generators such as a 62.5 MMBtu/hr steam flood generator (Permit S-1135-299) in Bakersfield, CA. Emissions from this burner were source tested at 15.4 ppmv NOx @ 3 % O_2 without FGR. The technology can be scaled to accommodate smaller burners.

Coen is also developing a variable geometry burner which uses movable burner elements to achieve the optimal configuration for a given firing rate and air to fuel ratio. According to laboratory results, this technology is capable of NOx emissions as low as 5 ppmv.

Option 2a: Selective catalytic reduction (SCR) - ammonia or urea injection: Selective catalytic reduction (SCR) is a developed technology which has been available and installed at various sites for approximately 20 years, although boiler applications have only been fielded in the last ten years. Advantages of this system include flexibility in handling a wide range of exhaust streams and operating conditions. Selective Non-Catalytic Reduction Systems (SNCR) require the reagent to be precisely injected into the exhaust to meet a current operating condition and can result in too much or too little reagent. Selective Catalytic Systems (SCR), on the other hand, tend to collect excess ammonia on the catalyst and are therefore pre-loaded with reagent and can handle sudden surges in the NOx emissions without excessive ammonia emissions or "slip".

The requirement for the reagent and the cost of monitoring and injection controls have typically made SCR cost-prohibitive for wide-scale application. The safety concerns about the storage and use of gaseous ammonia have also slowed acceptance of these systems, although aqueous ammonia may also be used as an effective reagent. Locations which use or generate urea as part of their normal operations, may choose that reagent, despite the somewhat higher cost compared to ammonia.

The cost of SCR has historically limited application to larger boilers. Due to changes in air pollution limits, small, package-type SCR are under development by Peerless, Siemens, and HISCorp. These units haven't yet been applied to working boilers within the District, but similar units have been used on mobile engines and large boilers so increased availability and application of this control technology is expected.

Option 2b: Cannon Technology Low Temperature Oxidation (LTO): The LTO system is similar to the SCR system but uses ozone rather than ammonia as the reducing agent. The LTO system requires either liquid oxygen (LOx) storage tank or an oxygen generator to provide the feedstock for the ozone generator. The ozone is generated from the oxygen using a corona discharge system and then injected into the exhaust stream. The ozone reacts with NOx to form nitric acid. A packed tower scrubber with two scrubbing chambers removes the acid and any excess ozone from the exhaust stream. As indicated in Appendix C, this technology established LAER in the South Coast AQMD at 5 ppmv NOx and 15 ppmv CO @ 3% oxygen in April 1998.

Because ozone is unstable above 400° F, a heat exchanger is required to cool the exhaust stream below this temperature. The manufacturer claims a 12% recovery rate with their dual exchangers compared to an industry average of 5% using a normal economizer. This results in decreased fuel costs but may cause stack gas condensation and flow problems if the temperatures are cooled too low. The fuel cost savings is partially offset by increased operating costs due to ozone generation and the operation of the scrubber. Effluent from the scrubber is a sufficiently dilute solution of sodium nitrate that can be discharged directly into a sanitary sewer without further treatment or hazardous material disposal costs.

The LOx tanks are owned and maintained by the supplier of the gas. This ensures the safety of the system as it is inspected by the supplier at each filling. Filling can be configured so that the system automatically calls for an oxygen delivery when the supply reaches a predetermined level.

System size and complexity are approximately similar to SCR while the operating costs (excluding the fuel savings) appear to be higher. Although the system has been tested to control high concentrations of NOx, there is an apparent system response lag which would make the system unsuitable for rapidly changing emissions which do not have significant periods of steady-state operations.

Because this system has only been installed at one location, the District does not have sufficient data to consider this to be achieved in practice except for that vary narrow application. However, LTO shall be considered a technologically feasible option for forced draft applications. Because of the SCAQMD LAER determination, more LTO units are expected to be installed in the future. The District will revisit its classification as this technology is more widely applied in the field.

Option 3: Low-NOx burners: The 30 ppmv technology has been demonstrated by source tests (Appendix A) of both large and small boilers and indicates actual operation in the 20 - 30 ppmv range and is easily attainable with many common low-NOx burners. With the compliance dates for RACT and BARCT controls (District Rule 4351 and 4305, respectively) having either passed or approaching soon, the majority of existing, full-time boilers have been retrofit with this technology in sufficient numbers as to consider this the de facto industry standard. The test results show a sufficiently large enough safety margin to expect these units to continue to comply despite normal wear of the system components.

The 20 ppmv level is being demonstrated in an increasingly large variety of sources. Some common burners can reach this level by merely increasing the FGR rate but such a change may require a larger fan motor, resulting in higher equipment and operating costs. The ultra-Low-NOx (ULN) systems can easily achieve the 20 ppmv and are commonly operated below this level when allowed or required by permit condition. This level provides a good compromise between minimal NOx emissions and increased boiler output. For ULN burners with FGR, the recirculation rates can be decreased by half, compared to the rate when operating at 9 ppmv. The lower FGR rates allows an increase in combustion air and fuel which results in higher heat output.

Low-NOx burners typically have good response characteristics with a turn-down ratio (the ratio between the high fire rate and the low fire rate) of 10 to1. They can fire on both liquid or a secondary gaseous fuel although the NOx emissions are not typically as low when firing on liquid fuel (40 ppmv) due to increased fuel NOx formation and limitations on burner design. Some designs may use a second, coaxially located burner for the backup fuel.

Although Low-NOx burners are typically operated at 20 - 30 ppmv NOx, the District's BACT level range of 14 - 30 ppmv reflects recent changes to this technology. For example, Texaco California Inc. is installing 13 new and 23 retrofitted 62.5 MMBtu/hr oilfield steam generators which will achieve 14 ppmv with Low-NOx burners and modified FGR systems.

Step 2 - Eliminate Technologically Infeasible Options

Option 1a: Alzeta Radiant Cell Burner: The District is not aware of any Alzeta burners fired on liquid fuel. This limitation could be important at some sites, such as hospitals or military installations, which require diesel as a backup fuel and rely on a single boiler. Therefore, Alzeta burners are not considered technologically feasible for dual-fuel installations, if diesel is required as a backup fuel.

The company does not currently have and, to our knowledge, is not developing a package for oilfield steam generators. Alzeta conducted tests in an oilfield steam generator in 1977 to gather test data for other applications such as refinery boilers. Chevron, the owner of the test unit, reported hot spots in the steam generator firebox. The Alzeta representative confirmed this observation.

Option 1b: Todd/Radian Rapid Mix Burner (RMB): At low firing levels, the air-to-fuel ratio must be tightly controlled or the rapid swirling characteristics of this burner can blow out the flame. The turn-down ratio is therefore limited to approximately 7:1 using a traditional economizer system and ambient combustion air. Due to increased complexity in controlling the air-to-fuel ratio, the turn-down ratio drops to approximately 4:1 when the exhaust heat exchanger is used to preheat the combustion air. Since most operators will preheat the boiler water with the economizer, this is not normally an operating constraint.

Responsiveness of the RMB to load fluctuations has been of concern to some operators. These units have a response time of approximately three minutes from idle to full fire. For burners supporting a rapidly changing load, this can be of significance, but the system has been successfully used at a facility with load swings of up to ± 20%.

Early Rapid Mix Burner systems which were installed with this system experienced some control problems at low fire which caused the flame to be blown out, allowing the unburned fuel to collect in the burner housing. When the system automatically restruck the flame, the unburned fuel would be ignited, resulting in either minor "puffs" or, in one case, an undocumented boiler explosion. These instances appear to be the result of either operator error or trying to use traditional burner controls with the advanced RMB technology. Current installations (Appendices A and C) use improved controls which can offer better responsiveness and a broader operating range to avoid flame out conditions. Operator reports indicate that, with the new controls and proper tuning procedures, the earlier safety problems have not reoccurred. The District is convinced that these early developmental problems have been resolved with today's more advanced burner control systems. The ever-improving ability to more accurately control the air-to-fuel mixture at low firing rates has apparently solved this potential safety problem.

On the subject of boiler safety, a boiler exploded at Ford's Rogue River Plant in Michigan on February 1, 1999. While the final report is not due out until August 1999, preliminary findings indicate that the explosion may have resulted from a leaky gasoline valve which was scheduled for replacement. Nonetheless, this boiler was not equipped with a RMB system, or any other low-NOx control technology, contrary to assertions from a local boiler operator. In fact, the boiler had actually been shutdown and disconnected from the fuel supply for routine maintenance at the time of the explosion so there is no possibility that the tragedy could have been caused by any burner system failure.

The company does not currently have a system designed for oilfield steam generators. The company has never worked with oilfield steam generators. According to Todd Combustion, the burner control system is required to maintain a set point of +/- 5% of excess air . The control system will not work if the Btu content of gas varies by more than +/- 2%. This level of control is necessary to maintain flame stability and greater variations in fuel Btu content/excess air may result in excess vibration, a detached flame, or flame blowout.

Texaco California, Inc. has supplied information on the gas quality available from its non-PUC regulated pipeline carrier and the variation of Btu content for other gas supplies i.e. their produced gas and gas purchased from other oilfield sources. This information indicates that the Btu content of the gas varies by more than +/- 2%. To achieve 9 ppmv, advanced controls are necessary to precisely control the air fuel premix. It is unknown if these controls could be used in oilfield with remote, unattended operations and a gas supply which varies in heat content. Therefore, at this time, the RMB system is not considered technologically feasible for applicable to oilfield steam generators.

For similar applications where the Btu content of the fuel gas can vary significantly (e.g. refinery gas) the manufacturers information indicates that 30 ppmv @ 3% O2 may be achievable.

The ULN burners are currently not available for burners rated less than 20 MMBtu/hr and, therefore, cannot be considered to be technologically feasible for that class and category of source. As the technology is expanded to include these smaller burners, the District will revisit this determination.

Options 1a and 1b: ULN burners rely on forced air to obtain proper combustion characteristics. Some large unit, such as refinery heaters, may not be available with forced air. Due to the size and fuel consumption, it is simpler and more economical to use natural draft units for some of the large scale applications. The lack of customer need for large, forced draft units has resulted in a complete lack of availability of such equipment. Therefore, ULN burners would not be technologically feasible for natural draft applications.

Option 1c: Coen Quantum Low-NOx (QLN) and Variable Geometry Burners (VGB): The QLN system has been source tested on an oilfield steam generator at less than 20 ppmv in October of 1995 . The equipment appears to be functioning well and has demonstrated itself to be a safe and effective control. Therefore, the emission level represented by this system is considered an Achieved-In-Practice standard for this class and category of source.

The 5 ppmv variable geometry burner is currently considered by the District to be a laboratory prototype which has not demonstrated on a working unit. Therefore, at this time, the Coen burners are only considered to be technologically feasible at the 20 ppmv range. However, Coen is presently installing a new VGB at Sacramento Steam and the District will continue to monitor development of this technology.

Option 2a: Selective catalytic reduction (SCR): SCR is not considered technologically feasible for high sulfur applications. High-sulfur fuel applications are those where it is not cost effective to remove the sulfur from either the fuel or the exhaust stream and that sulfur would mask or poison the catalyst.

Option 4: Electrical Heaters: Electrical heaters are typically limited to units less than 5 MMBtu/hr and are not manufactured for larger units. Therefore, electrical heaters are not considered to be technologically feasible for boilers and steam generators in this class and category.

The other control options are considered to be technologically feasible for the applications which are within their specific operating limitations as discussed in Step 4, below.

Step 3 - Rank Remaining Control Technologies

After eliminating the technologically infeasible options, the remaining options are ranked according to either their control efficiency or their emission factor. Any option which ranks below an achieved in practice option is not listed because the achieved in practice option represents the minimum control device or maximum emission factor which is required by law. Since this determination involves controls for a variety of classes and categories of sources, the achieved in practice/technologically feasible status is not listed in the ranking table, but will be discussed in Step 4.

Table 1: Control Technology Ranking

Rank	Emission Factor
1. Exhaust gas treatment (SCR or LTO)	$\leq$ 9 ppmv
2. Ultra-low NOx burners	9 - 15 ppmv
3. Low-NOx burners	20 - 30 ppmv

Step 4 - Cost Effectiveness Analysis

Control technologies that have been deemed to be technologically feasible but have not been deemed to have been achieved in practice can only be required as BACT if shown to be cost effective. By law, control techniques that have been achieved in practice for a class and category of source establish a floor and must be required for that class and category of source regardless of cost.

For technologically feasible measures that are more effective than achieved-in-practice controls, a detailed, site-specific cost effectiveness analysis is required. Such analysis will consider all costs that are attributable to the control technology beyond those for a standard device that is typically used by the industry. Examples of the types of costs that would be included in such an analysis are capital cost, utility cost, fuel cost, labor, and other operational and maintenance costs. For NOx, any control with an annual cost of more than $9,800 per ton of emission reduced is not considered to be cost effective.

A case-by-case analysis cannot be included here without site-specific data. Instead, for each affected source category, this document will identify the controls that have been achieved in practice and those that were found to be technologically feasible.

The District subscribes to a conservative philosophy in determining if a control technology has been achieved in practice. The District only deems a technology as having been achieved in practice if a control has been proved to work effectively over a reasonable time for the class and category of source in question. This conservative approach sometimes differs from the preference of USEPA and CARB. Both agencies advocate that once a level of control is achieved in practice for a particular type of equipment, then that type of control must be deemed as having been achieved in practice for all types of industries that utilize the same equipment.

The criteria is used by the District in designating a control as having been achieved in practice:

- The rating and capacity for the unit where the control was achieved must be approximately the same as that for the proposed unit.

- The type of business (i.e. class of source) where the emissions units are utilized must be the same.

- The availability of resources (i.e. fuel, water) necessary for the control technology must be approximately the same.

A. **Selective Catalytic Reduction:** Although this is a mature technology, the complexity and expense of a properly operating SCR system have limited it to special applications. Within the District, SCR is commonly employed to control NOx emissions from large IC engines and turbines. A search of the permit database indicated that there were no boilers controlled by SCR. Due to limited application, the District does not consider SCR as having been achieved in practice for source categories covered by this determination. The use of SCR on boilers, however, has been demonstrated to be technologically feasible and may be required on a case-by-case basis if found to be cost effective.

B. **Ultra-Low NOx (UNL) Burners:** As indicated in this analysis, ULN burners, either with or without FGR, are available from at least two manufacturers and have been operated for several years at a number of locations (see Appendices A and C). However, due to their design, ULN burners are limited in their ability to respond to highly variable loads and also have a limited turndown ratio compared to conventional burners. For stable operating applications, however, the ULN burners have proved capable of sustained operations of $\leq$ 9 ppmv and are, therefore, deemed to be Achieved in Practice for these base-loaded applications (i.e., 25% or less load fluctuation) excluding installations firing gases with high ammonia content. Applicants with multiple boilers will be required to manage their steam demand and distribution, to extent that is compatible with their operational needs, in a manner that would allow base loading of new boilers subject to BACT.

The ammonia content of some biogas and refinery gases is sufficiently high to create a measurable increase in NOx emissions from ULN burners. Because of the variability in the ammonia concentration, it is not possible to adequately reduce these emissions with combustion controls. For this reason, the District determines that the Achieved in Practice level for this class and category of source is 30 ppmv.

As for load following boilers, available data increasingly points towards satisfactory operation at 9 ppmv with high turndown ratios and fairly rapid load changes. However, satisfactory operation at 9 ppmv requires advance controls and adequate operator training. At this point, the District is not satisfied that sufficient data to conclude that 9 ppmv can be achieved routinely and continually in all cases for such boilers exist. Therefore, at this time, 9 ppmv is not considered to be achieved in practice for load following boilers. However, 15 ppmv @ 3% O_2 has been achieved in practice for a number of applications without much difficulty. In fact, a number of installations permitted at 30 ppmv have voluntarily achieved and maintained 15 ppmv or less. Given the remaining minor uncertainties with achieving 9 ppmv with load following boilers, the District will allow facilities sufficient time to experiment and consider site-specific conditions in determining the feasibility of 9 ppmv NOx level for each application. Under these circumstances, the applicants will be required to install systems that are capable of achieving 9 ppmv, but up to one year will be allowed to determine if the unit can satisfactorily be operated at 9 ppmv. If the unit can not achieve 9 ppmv despite proper operation and maintenance, then a site-specific BACT limit of no more than 15 ppmv which represent the best that unit can satisfactorily achieve will be established.

ULN burners are not readily available for small applications of 20 million Btu/hr or less. Therefore, ULN burners are not considered to be achieved in practice for this class and category of source.

Also, ULN burners are primarily designed for gaseous fuels and do not control NOx as effectively from liquid fuel such as diesel. Hospitals, and similar facilities, are required to have a secondary fuel supply in case the primary fuel supply is interrupted. The District is not aware of any ULN burners in dual-fired installations. Therefore, the District does not consider ULN burners as having been achieved in practice for boilers that are required to have dual fuel capability.

C. **Low NOx Burners:** Low NOx burners achieving 20 to 30 ppmv @ 3% O2 are considered to be achieved in practice for all applications where it is not technologically feasible to apply an ULN burner system.

In some applications, the Low-NOx burners with FGR may achieve 14 ppmv. As was previously indicated, an oilfield steam generator was source tested at less than 15.4 ppmv on October of 1995. The equipment appears to be functioning well and has demonstrated itself to be a safe and effective control. Due to variations in fuel quality and the remote, unattended operation of steam generators, the District believes 20 ppmv to be a reasonable, maintainable emission standard. Therefore, 20 ppmv is considered the Achieved-In-Practice standard for this class and category of source.

Texaco California Inc is installing 13 new and 23 retrofitted 62.5 MMBtu/hr oilfield steam generators which will achieve 14 ppmv with Low-NOx burners and modified FGR systems. Therefore, that level will be considered to be the technologically feasible level for that class and category of source.

Step 5 - Select BACT

The following is a summary of the District's BACT determination for the discussed systems. BACT standards are based on the emission levels shown. The control systems are listed for informational purposes and do not reflect a BACT requirement nor do they reflect that such technology would necessarily be equivalent to the indicated BACT emission standard.

BACT Summary Table

Class and Category	Achieved in Practice	Technologically Feasible
Natural Gas-fired < 20 MMBtu/hr	20 ppmv @ 3% oxygen - Low-NOx Burner	1. 9 ppmv [1] @ 3% oxygen - SCR or LTO 2. 15 ppmv @ 3% oxygen - Low-NOx Burner
Natural Gas-fired > 20 MMBtu/hr Based Loaded or Small Load Swings [2].	9 ppmv @ 3% oxygen - ULN Burner	9 ppmv [1] @ 3% oxygen - SCR or LTO
Natural Gas-fired[3] > 20 MMBtu/hr with a Highly Variable Load or a High Turndown ratio [4] requirement	$\leq$15 ppmv[5,6] @ 3% oxygen - ULN Burner	9 ppmv [1] @ 3% oxygen - ULN, SCR or LTO
High-Ammonia Fuel > 20 MMBtu/hr	$\leq$30 ppmv[5,6] @ 3% oxygen - ULN Burner (derated emission factor)	9 ppmv [1] @ 3% oxygen - SCR or LTO
Refinery Gas-fired > 50 MMBtu/hr	9 ppmv @ 3% oxygen - SCR	9 ppmv @ 3% oxygen - LTO
Hospitals[3] - Natural Gas with Diesel Fuel Backup	20-30 ppmv[5,6] @ 3% oxygen - Low-NOx Burner	9 ppmv [1] @ 3% oxygen - SCR or LTO
Steam Generator – Oilfield	20 ppmv @ 3% oxygen - Low-NOx Burner	9 ppmv [1] @ 3% oxygen - SCR or LTO 14 ppmv @ 3% oxygen - Low-NOx Burner w/FGR

Notes:

1 - SCR is not technologically feasible in high-sulfur fuel applications, but is considered technologically feasible if the sulfur is removed before the SCR inlet.

2 - Load swings within the ULN burner's stated 9 ppmv NOx response curve.

3 - Only applies to facilities with a single unit or a facility with multiple units which are independently operated.

4 - A Highly Variable Load and High Turndown Ration are considered to be normal operation which exceeds the ULN burner's stated capabilities @ 9 ppmv levels.

5 - BACT will be established on a case-by-case basis to assure lowest achievable emissions rate taking into account unique facility characteristics.

6 - The following conditions will be cited on the permit:

"NOx emissions shall not exceed the lowest achievable level. Lowest achievable level shall be established based on source testing no later than 180 days after initial start-up at normal operating load(s) and under design and operational parameters achieving optimum NOx emissions."

"In conjunction with the test results, the permittee shall submit written documentation demonstrating that the unit was designed, constructed, and operated for optimum NOx emissions."

"Under no circumstances shall the NOx emissions exceed XX ppmv (the highest indicated achieved in practice emission rate) @3% O2."

"Once established, the lowest achievable NOx level shall be reflected as a condition on the Permit to Operate."

Appendices:

Appendix A: Boiler Source Test Summary
Appendix B: District Policy BACT-1
Appendix C: Summary of ULN boiler and ULN control systems

Appendix A: Boiler Source Test Summary

The following tables include sources test results for boilers currently under permit in the District and districts in California. The first table results indicate emissions for equipment controlled by low-NOx burners and flue gas recirculation (FGR) systems. The permitted levels for these units is typically 30 ppmv, the BACT standard at that time. The second table indicates emissions from the indicated control technologies.

Low-NOx Burner Source Test Results

Facility	Test Date	Unit Size MMBtu/hr	NOx @3% O_2
0646: Hunt Wesson	8/18/97	75	25.8 ppmv
0646: Hunt Wesson	8/18/97	95	23.6 ppmv
0646: Hunt Wesson	8/18/97	130	26.1 ppmv
0787: Los Gatos Tomato Products	6/6/97	95	28.6 ppmv
0787: Los Gatos Tomato Products	6/6/97	95	28.2 ppmv
0787: Los Gatos Tomato Products	6/6/97	104	28.0 ppmv
1163: SK Foods	6/19/97	89	23.7 ppmv
1163: SK Foods	6/19/97	89	23.3 ppmv
1243: TomaTek	6/17/97	108	22.1 ppmv
1243: TomaTek	6/17/97	108	20.4 ppmv
1243: TomaTek	6/17/97	108	21.0 ppmv
1243: TomaTek	6/17/97	33	21.6 ppmv
1333: Valley Medical Center	8/14/97	13	25.5 ppmv
1333: Valley Medical Center	8/14/97	13	27.0 ppmv
1333: Valley Medical Center	8/14/97	13	23.3 ppmv
1135: Arco Western Energy	10/26/95	62.5	15.4 ppmv

Ultra Low NOx Source Test Results and Proposed Projects

Facility	Installed	Unit Size MMBtu/hr	Control Technology	NOx @3% O_2
Alta Dena Dairy, City of Industry	Oct 1996	16.4	LTO	< 5 ppmv
Darling Delaware, Los Angeles	Oct 1993	110	SCR	6 -7 ppmv
Hunt-Wesson, Oakdale	1996	110	RMB	< 9 ppmv
Hunt-Wesson, Oakdale	1996	196	RMB	< 9 ppmv
Hunt-Wesson, Davis	1996	110	RMB	9 - 11 ppmv
Morning Star, Los Banos	1996	110	RMB	9 ppmv
Morning Star, Williams	1995	110	RMB	< 15 ppmv
Proctor & Gambles, Sacramento	1997	110	RMB	9 ppmv
UC Irvine Medical Center	1996	49	Alzeta	7 ppmv
Danish Creamery, Fresno	April 1999	67	RMB	< 9 ppmv
Morning Star, Los Banos	ATC 1999	178 & 90	RMB	
Stanislaus Food Products	ATC 1999	94	9 ppmv RMB or equivalent	
Los Gatos Tomatoes, Huron	ATC 1999	182	9 ppmv RMB	
SK Foods, Lemoore	ATC 1999	190	9 ppmv RMB	
Guild Winery, Fresno	ATC 1999	57	9 ppmv Alzeta	
Texaco California, Inc.	ATC 1999	13 x 62.5	14 ppmv LNB w/FGR	

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Appendix C: Summary of ULN boiler and ULN control system information

The USEPA provided a list of units which employ an ULN technology. The operators and manufacturers of the systems were contacted to gather information about the technologies and operational histories of those unit.

1. Alzeta Radiant Heat Burners

a) UC Irvine Medical Center, Irvine:
This is a 48.6 MMBtu/hr boiler with Alzeta "Pyromet" radiant heat, flameless burners. The unit has been permitted since 1996 at 9 ppmv NOx @ 3% oxygen and tested at 7 - 7.5 ppmv NOx. The project was cofunded by the gas company, the Calif. Energy Commission, et al.

- Spoke with J.W. Taylor, (714)456-5192, at UCI. He appeared satisfied with the system which has been running since April 1993. Emissions have been below 9 ppmv NOx. It is rotated with three older boilers (< 30 ppmv variety) so actual firing time is approximately 25% of the year. According to Mr. Taylor, the Alzeta burners are nearly maintenance-free but the ceramic surface is very delicate. No problems have been noted with the ceramics and it hasn't cracked or become clogged. Annual tuning is accomplished by manufacturer's representatives. The Alzeta burners do not appear to require special tuning or maintenance and haven't exhibited any long-term operation problems.
- Because Mr. Taylor supports a hospital, he would have liked a dual-fuel (gas/diesel) burner in case of natural gas interruption. He has dual-fuel boilers but this limitation could be important at some single-boiler sites. Alzeta burners require propane or LPG for backup fuel. He did not know about the boiler efficiency but was installing a totalizer and some other controls to better monitor individual boiler.

b) Contadina, Woodland:
This is a 180 MMBtu/hr seasonal (three months/year) tomato processor boiler with an Alzeta burner operating at 6 ppmv NOx. It was installed in July 1997. The operator is concerned about the efficiency of the unit at this NOx level and is planning to adjust the air-fuel ratio which will increase NOx closer to the permitted levels of 20 ppmv. (Note: Alzeta claims 80% boiler efficiency which is comparable to a low-NOx boiler.)

c). San Francisco Thermal:

120 MMBtu/hr year round cogeneration plant. Installed October 1996. Achieves 18 ppmv NOx @ 3% O2 35% excess air (7% oxygen). The District was unable to obtain further information about this facility.

d) Darling International, Crows Landing:
50 MMBtu/hr boiler used at a year-round animal parts rendering plant. The District was unable to obtain further information about this facility.

2. Todd/Radian Rapid Mix Burners (RMB)

a) Proctor and Gamble, Sacramento

Spoke with Dave Gross SMAPCD (916-386-7031) about the 106 MMBtu/hr P&G boiler. He stated that it used Todd/Radian Burners which had initial firing problems but are now working well after controls calibration from RF McDonald.

Called Kurt Peniger (916)381-292, the P&G Facility Manager, for further details:

- Their system has operated since September 1997. The boiler is rated at 90,000 lb/hour but cannot meet permitted emissions of 11 ppmv when fired above 85,000 lb/hr or less than 20% minimum firing level (zero steam produced). There is a 30 ppmv pilot burner for use at zero steam levels to keep the boiler warm. A 6:1 turndown ratio is achievable within emission limits, but a 10:1 ratio is desired.
- System requires quarterly tune-ups to keep within their permit limit of 11 ppmv. The system drifts from a tuned setting of 9 ppmv. Tuning should take less than three days but recently took three weeks. The process entails setting controller to perform correctly at various operating levels.
- Tuning must be accomplished with the boiler offline. There is no safe way to adjust the air-to-fuel ratio on-the-fly. Explosions at other facilities have resulted from on-the-fly adjustments so this facility brings in outside operator for adjustments.
- Mr. Peniger has talked to other operators and they have had problem with clogging of the small holes used for swirling as well as problems with slippage of the burner's dispersion cone. Such problems occur within five years. As part of the quarterly tune ups, he has been cleaning the mixing holes.
- Mr. Peniger's opinion is that such units are more suitable for boilers with relatively stable, continuous loads.

b) Hunt-Wesson, Davis

According to Mat Ehrhardt, YSAQMD AQE (530-757-3673), there are two 120 MMBtu/hr boilers which are fired by Todd/Radian burners. The point of contact at the plant was Ron Allen (530-757-0590).

- Ron Allen has operated the two burners since 1996 (seasonal operation, three to four months per year). A previous burner was replaced under warranty due to manufacturing problems with the mixing vanes. The boilers operates three or four months each season and are tuned in July before the start of the tomato processing season.
- Normal operating load is approximately 80% of rated maximum with a 10% to 20% swing in actual firing rate common during operations.
- Emissions are limited to 15 ppmv by permit and ERC have been received for the difference between that and the required 30 ppmv BARCT level. Actual emissions are 9 - 11 ppmv NOx.
- Tuning is conducted by factory personnel and takes about a day per boiler. Adjustments are determined under load but are "dialed in" when the burner is not firing.
- Mr. Allen stated that a good control system is necessary to keep the burners within specifications but that there have been no problems with his boiler retrofit.

c) Hunt-Wesson, Oakdale

There are two boilers (111 MMBtu/hr and 196 MMBtu/hr forced draft) controlled with Todd/Radian burners, as well as several low-NOx burners at this tomato processing plant. POC is Robert Plant (209-848-7223). Mr. Plant provided the following information:

- The burners have operated for three seasons since the retrofit of the existing boilers. Normal operation is four months per year although the 111 MMBtu/hr boiler (circa 1958 construction) will be operated for approximately 10 months in 1998 - 1999 as some reprocessing activities keep the facility running nearly year round.
- There were controller problems during the first two years which lead to two "puffs" that strained but did not seriously damage the boilers. The problems appear to be resolved with a new control system, but the burners require very precise air-to-fuel ratio control. Too much excess air generates a rumble and too little excess air causes panting.
- The more precise controls current control system dictates increased maintenance levels compared to standard burners. The Hunt-

Wesson boilers have passed the two annual source tests required by Rule 4701.

- Cracks in the burner riser welds will require a factory replacement after the 1998 season is completed. 20 ppmv CO levels resulted earlier in the season from the cracking, but the riser appears to have settled and CO is now below detection levels. NOx remained under the 9 ppmv setpoint.
- The 111 MMBtu/hr boiler is not based loaded but follows the load. Response time of the Todd/Radian is somewhat slower than a conventional 30 ppmv burner. A 5:1 turndown ratio is possible with this burner but only a 4:1 ratio can be achieved within the 9 ppmv range. At lower fuel levels, a higher NOx limit is required for increased flexibility.
- There was some concern that Todd's financial situation may affect the long-term availability of parts and service.

On April 7, 1999, District personnel, (Harvey Lopez, Rodney Swartzendruber, and myself) monitored the emissions from Hunt-Wesson's boiler #3 which was firing in conjunction with a conventional 30 ppmv boiler. Each boiler carried roughly half the facility load and was fired at between 50 - 60% of it's maximum rating with $\pm$ 5% load swings. Based on the average of sixty samples (attached), the boiler averaged 11.9 ppmv corrected to 3% oxygen. This was well within the 15 ppmv permit limit which was used to establish the boiler setpoint after the 1998 processing season. The data indicates that the RMB is a viable technology which can continually meet required emissions over an extended period.

d) Morning Star, Los Banos

130 MMBtu/hr boiler controlled by a Todd/Radian burner. The POC is Doug Kirkpatrick (209-827-7803). He discussed the burner with his operators and provided the following information.

- The boiler is a seasonal unit running approximately four months of the year for tomato processing operations. The burner is base loaded and has operated since 1996 for two seasons.
- The operators' impression was that the burner was very sensitive to load swings and requires a more sophisticated controller than is presently installed. Maintenance and tuning are performed by outside contractors due to the danger of explosion during system adjustments. No explosions or puffing were noted at this site, but Mr. Kirkpatrick was concerned about the general safety of the Todd/Radian burner due to earlier reports of problems.
- He has experienced no problems with the vanes, riser, or other burner components.

- Low-NOx (30 ppmv) boilers are used to follow the load for levels above what the Todd/Radian burner can provide.
- Morningstar has ordered additional RMB to be installed in 1999.

3. Cannon Technology Low Temperature Oxidation (LTO)

a) Alta Dena Dairy, City of Industry:

According to South Coast AQMD engineer Knute Beruldsen (909-396-3136), this is a 16.4 MMBtu/hr boiler equipped with the Low Temperature Oxidation (LTO) system which has operated since October 1996. Hoshik Yoo, SCAQMD BACT Coordinator, (909-396-2485) performed the BACT analysis for this project. He said that the LTO was required because one of the dairy's three boilers wasn't meeting the 30 ppmv limit. The project was funded by grants from US Dept of Energy and the gas company. In general, LTO is more expensive than SCR due to the cost for oxygen (used in ozone production), the increased fan power needed to overcome the two scrubbing tower pressure drop, and the scrubbing tower operation and solutions.

Spoke with manufacturing representatives, Art Skelley (412-335-8541) of Cannon Technologies and Jim O'Neill (626-855-5381) of BOC Gases. They provided the following information:

- Cost effectiveness numbers are enhanced by the lowered annual fuel costs resulting from the heat recovery portion of the system. The use of ozone requires operation at temperatures between 100 and 400 degrees Fahrenheit so an economizer must be installed prior to the injector to recover exhaust heat. The recovered energy can be used for preheating combustion air or feed water. Such heat recovery is essential to the system operation since ozone will breakdown at temperatures higher than 400 degrees Fahrenheit. Expected heat recovery is claimed to be 12% for the LTO system compared to 5% for the standard heat economizer typically used on boilers.

- Special financing and leasing options are available which can reduce the control system capital outlays. One option is to lease the system with payments based on the fuel amount of savings generated from the economizer operation.

- This system has also been source tested for use on a diesel engine and may also be suitable for turbines, steam generators and chemical processes that release NOx like stainless steel manufacturing, if exhaust temperatures are sufficiently low. Emissions from sources such as diesel engines may contain particulate materials which are captured by the scrubber and may required handling as hazardous waste. After the source test, the system LTO was removed from the engine.

Spoke with Dan Wynans (626-854-4222) of Alta Dena Certified Dairies who provided the following information:

- The boiler is a load-following unit which is operated 24 hours/day and 365 days/year to process dairy products. No problems have been encountered with the control system.

- Maintenance of the ozone generator has been streamlined using nitrogen-washing which does not require the system to be dismantled.

4. Selective Catalytic Reduction:

a) Shell Refinery Boiler

According to Greg Stone, BAAQMD AQE (415-749-4745), this facility includes is two SCR-controlled boilers which has been operating since 1987.

Spoke with Barry Young (415-749-4721) the Bay Area BACT coordinator and discussed their BACT finding. He provided the following information:

- They have BACT for Shell refinery process heaters based on an ATC for a refinery "furnace" . From the project description, it appears the furnace is a process heater used to directly heat crude oil or partially refined feedstock. The heater has been constructed and running as part of the clean fuel project. It is in compliance with a 10 ppmv NOx limit. The project also included a supplemental heat boiler on a cogeneration turbine that has SCR and a 5 NOx ppmv limit (Boiler 6 Supplemental steam generators #1 and #2, rated 56 MMBtu/hr each) issued 12/27/93and apparently fired on refinery gas. The ATC required separate CEMS, SCR and CO/VOC oxidizer for each boiler.

- Their boiler BACT determination was the result of a August 12, 1994 proactive determination. The determination was based on existing boilers (>50 MMBtu/hr) which had been installed and operating for at least a year. No ultra-low NOx burners have been installed but there have been several applications for such equipment.

Appendix B: District BACT Policy
(Not Attached)

INFROMATION REPORT
OLD PERMIT NUMBERS
AND
COMMENTS

OLD PERMIT NUMBER	BUSINESS NAME	DATE ISSUED	NEW	#		COMMENT	OLD PROJECT NUMBER	NEW PROJECT NUMBER
6036-011	UPF CORPORATION	03/17/89	1126	11	0	WEIGHING & MIXING AREA @FILTRATION MEDIA PROD.LINE	88622	88622
6036-011-A	UPF CORPORATION	08/07/91	1126	11	1	MODIFY EMISSION SAMPLING LIMIT	91130	91130
6036-012	UPF CORPORATION	03/17/89	1126	12	0	MIXED BATCH FEED AND FURNACE FOR FILT. MEDIA LINE	88622	88622
6036-012-A	UPF CORPORATION	03/17/89	1126	12	1	ADD LPG AS ALT FUEL: ISSUED 1-13-90-RENEW 3-08-91	891130	891130
6036-012-B	UPF CORPORATION	08/12/91	1126	12	2	REDUCE MINIMUM STACK TEMPERATURE OF FURNACE	91227	91227
6036-012-C	UPF CORPORATION	12/30/92	1126	12	3	NO EMISSION CHANGE PROJECT	92826	92826
6036-013	UPF CORPORATION	03/17/89	1126	13	0	ATTENUATION,FIBER FORMING,CURING,FABRICATION	88622	88622
6036-013-A	UPF CORPORATION	03/17/89	1126	13	1	ADD LPG AS ALT FUEL:ISSUED 1-13-90-RENEW 3-08-91	891130	891130
6036-013-B	UPF CORPORATION	05/21/92	1126	13	2	ADD FLARE TO PROPANE VAPORIZER (C & R BY 6036013C)	91612	
6036-013-C	UPF CORPORATION	03/17/91	1126	13	3	INCREASE SOX AND CO EMISSION LIMITS. (5-21-92)	92316	92316
6036-014	UPF CORPORATION	08/07/91	1126	14	0	FIBERGLASS CURING OVEN-CANCELLED PER REQ. WZI	91130	
6036-015	UPF CORPORATION	12/02/91	1126	15	0	3747 STANDARD STREET, EMERGENCY POWER IC ENGINE	91614	91614
6036-999	UPF CORPORATION	03/08/91	1126	16	0	2 RENEWALS FOR FIBERGLASS PRODUCTION OPERATION	91222	91222
6036-999-A	UPF CORPORATION	04/09/91	1126	16	1	ATC RENEWAL FOR GLASS MELING LINE #1 6036008A	91321	91321
6037-001	CHEMWEST INDUSTRIES, INC.	/ /	1850	959	0	CONTINUOUS FERROUS CHLORIDE PRODUCTION UNIT #1	89209	
6037-002	CHEMWEST INDUSTRIES, INC.	/ /	1850	960	0	CONTINUOUS FERROUS CHLORIDE PRODUCTION UNIT #2	89209	
6037-003	CHEMWEST INDUSTRIES, INC.	/ /	1850	961	0	CONTINUOUS FERROUS CHLORIDE PRODUCTION UNIT #3	89209	
6037-004	CHEMWEST INDUSTRIES, INC.	/ /	1850	962	0	FERRIC CHLORIDE PRODUCTION UNIT	89209	
6037-005	CHEMWEST INDUSTRIES, INC.	/ /	1850	963	0	HYDROCHLORIC ACID TRUCK	89209	

Ad Hoc Governing Board Subcommittee for Best Available Control Technology (BACT) for Natural Gas- Fired Boilers, Steam Generators, and Process Heaters.

Public Meeting
June 10, 1999
12:00 - 3:00 PM

Agenda

1. Introductions and opening remarks - Chair Kenni Friedman
2. Opening remarks - David L. Crow, Executive Director/APCO
3. Presentation of draft BACT Determination - District Staff
4. Comments - EPA Staff
5. Comments - ARB Staff
6. Public Comments
7. Summary - District Staff
8. Closing Comments - Chair Kenni Friedman

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FINAL REPORT
1997 EMISSION COMPLIANCE TESTS AT
THE CROCKETT COGENERATION
FACILITY

Prepared For:

CROCKETT COGENERATION, L.P.
Crockett, California

For Submittal To:

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
San Francisco, California

Prepared By:

Kevin J. Crosby

CARNOT
Concord, California

AUGUST 1997

SECTION 1.0

INTRODUCTION

Carnot was contracted by Crockett Cogeneration, L.P. to perform the 1997 emission compliance tests at the Crockett Cogeneration facility adjacent to the C&H Sugar refinery in Crockett, California. The testing program included measurement of emissions at full load from Auxiliary Boiler B, and at full load on the gas turbine and heat recovery steam generator (HRSG). Additional tests were conducted on the gas turbine/HRSG unit during start up and shutdown conditions, but they are reported separately.

Emissions were measured as required by the proposed Permit to Operate (Application Number 17076) issued by the Bay Area Air Quality Management District (BAAQMD) to Crockett Cogeneration, a California Limited Partnership. Tests were performed to measure emissions of the following parameters:

- NO_x, CO, POC
- Ammonia
- Total particulate matter as PM_{10}

The results of these tests are presented in this report to determine compliance with the emission limit conditions of the Authority to Construct.

The tests were performed on June 16 through 18, 1997 by Kevin Crosby, John Pascale, and Jeff Hogan of Carnot. Unit operations were coordinated by Mr. Audun Aaberg of Crockett Cogeneration. No direct observations of the tests were made by BAAQMD personnel, but they were notified of the test schedule. The tests were conducted according to a test plan submitted by BAAQMD.

The average test results are summarized in Tables 1-1 through 1-3. Detailed results summaries for the individual test runs are presented in Section 4.0.

SECTION 2.0

FACILITY DESCRIPTION

The Crockett Cogeneration Project includes three auxiliary boilers and one combined-cycle gas turbine generator unit located adjacent to the C&H Sugar refinery in Crockett, California. The 240 MW cogeneration facility provides electrical power for Pacific Gas & Electric Co. (PG&E), and process steam and power to the C&H Sugar refinery. There are three identical Foster-Wheeler auxiliary boilers, all fired on natural gas. Each boiler unit includes a selective catalytic reduction (SCR) unit for control of NO_x emissions. The turbine unit includes a General Electric Frame 7FA combustion gas turbine and a heat recovery steam generator (HRSG). The HRSG includes supplementary duct burners for additional steam production, and a SCR unit for control of NO_x emissions. Emission limits imposed by the Authority to Construct are shown in Table 2-1.

The exhaust from each auxiliary boiler is ducted to a vertical, cylindrical stack. These three stacks are grouped together, and are immediately adjacent to the turbine/HRSG stack. The sampling locations for all four stacks are accessed from a single platform.

TABLE 1-2
SUMMARY OF AVERAGE TEST RESULTS
AUXILIARY BOILER B
CROCKETT COGENERATION
JUNE 1997

Parameter	Full Load	Permit Limits
Stack Gas		
Temp., °F	308	–
Flow, dscfm	64,146	–
H_2O, % vol.	16.2	–
O_2, % vol. dry	4.11	–
CO_2, % vol. dry	9.66	–
NO_x, ppm @ 3% O_2	5.47	8.2
Ammonia, ppm @ 3% O_2	4.92	20
CO, ppm @ 3% O_2	3.24	11.0
Emission Rate, lb/hr		
NO_x as NO_2	2.35	3.7
CO	0.85	3.0
POC as CH_4	0.057	–
Total PM as PM_{10}	0.505	–

Notes: Individual test run data are presented in Section 4.0.

TABLE 4-2
EMISSION TEST RESULTS SUMMARY
AUXILIARY BOILER B
CROCKETT COGENERATION
JUNE 1997

Parameter	4-PM-BB	5-PM-BB	6-PM-BB	Average
Test Condition:	Full Load	Full Load	Full Load	
Date:	6-18-97	6-18-97	6-18-97	
Time	0801-1011	1035-1238	1302-1505	
Stack Gas				
Temp., °F	304	310	310	308
Flow, dscfm	63,765	66,150	62,522	64,146
H_2O, % vol.	16.2	15.5	17.0	16.2
O_2, % vol. dry	4.24	4.43	3.67	4.11
CO_2, % vol. dry	9.62	9.49	9.88	9.66
NO_x, ppm @ 3% O_2	6.12	5.31	4.99	5.47
Ammonia, ppm @ 3% O_2	3.65	5.23	5.87	4.92
CO, ppm @ 3% O_2	2.35	1.67	5.69	3.24
Emission Rate, lb/hr				
NO_x as NO_2	2.59	2.31	2.14	2.35
CO	0.61	0.44	1.49	0.85
POC as CH_4	<0.003	<0.003	0.166	0.057
Total PM as PM_{10}	0.412	0.821	0.282	0.505

PM denotes filterable particulate matter (front-half only), from EPA Method 5.

The Avogadro Group

6/98

FINAL REPORT FOR 1998 EMISSION COMPLIANCE TESTS AT CROCKETT COGENERATION CROCKETT, CALIFORNIA

Prepared for:

CROCKETT COGENERATION, L. P.
Crockett, California

for Submittal to:

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
San Francisco, California

And to:

CALIFORNIA ENERGY COMMISSION
Sacramento, California

Prepared by:
Kevin J. Crosby
July 24, 1998

R98045

1.0 INTRODUCTION

The Avogadro Group (AG) was contracted by Crockett Cogeneration (Crockett Cogen) to perform a series of emission source tests. The testing program was conducted to determine compliance with the conditions of the Permit to Operate issued by the Bay Area Air Quality Management District (BAAQMD). Emissions were measured from one gas turbine with heat recovery steam generator (HRSG), and from one of three auxiliary boilers.

The testing data and results for emissions of criteria pollutants are presented in this report, which includes descriptions of the facility and the sampling locations, and descriptions of the testing procedures, calculations and quality assurance data. A separate report has been prepared for the emissions of toxic air contaminants.

The testing program was conducted on June 15 to 23, 1998 by Kevin Crosby, Erick Mirabella, Jeff Hogan and Dan Duncan of The Avogadro Group. Unit operations were coordinated by Audun Aaberg of Crockett Cogeneration, with the assistance of the shift supervisors and board operators that were on shift during the tests. The BAAQMD was notified of the test schedule, but no direct observations of the tests were made by District personnel.

The average test results are summarized in Tables 1-1 and 1-2. Detailed results summaries for the individual test runs are presented in Section 4.0.

TABLE 1-1
SUMMARY OF AVERAGE TEST RESULTS
AUXILIARY BOILER C
CROCKETT COGENERATION
JUNE, 1998

Parameter	Average Result	Permit Condition
Stack Gas		
Temperature, °F	322	-
Flow, dscfm	75,663	-
H_2O, % vol	14.9	-
O_2, % vol dry	5.64	-
CO_2, % vol dry	8.64	-
Concentration, ppm @ 3% O_2		
NO_X	5.39	8.2
CO	6.02	11.0
Ammonia	5.84	20
Emission Rate, lb/MMBTU		
NO_X as NO_2	0.0065	-
CO	0.0045	-
Total PM as PM_{10}	0.0029	-
Emission Rate, lb/hr		
NO_X as NO_2	2.48	3.7
CO	1.35	3.0
POC as Methane	0.09	-
Total PM as PM_{10}	1.10	-

Note: There are other permit conditions that have not been directly addressed in this table. The data presented here can be used in calculations to address those daily and annual emission rate limits.

2.0 EMISSION SOURCE INFORMATION

2.1 Facility Description

The Crockett Cogeneration facility includes one combined-cycle gas turbine generator unit and three auxiliary boilers located adjacent to the C&H Sugar refinery in Crockett, California. The 240 MegaWatt cogeneration facility provides electrical power for Pacific Gas & Electric Company (PG&E), and process steam to C&H Sugar.

The turbine unit is a General Electric 7FA combustion gas turbine with steam augmentation, and with a steam turbine that applies power to the same output shaft for generation of electricity. The exhaust gases from the turbine flow horizontally through a heat recovery steam generator (HRSG). The Vogt HRSG includes supplementary duct burners for additional steam production, and SCR and reduction catalysts for control of NO_x, CO and other emissions. The exhaust gases from the gas turbine and HRSG are ducted to a vertical, cylindrical stack.

There are three identical Foster-Wheeler auxiliary boilers, each fired with natural gas and rated at approximately 40,000 lb/hr steam production. Each boiler unit includes a selective catalytic reduction (SCR) unit for control of NO_x emissions. The exhaust from each boiler is ducted to a vertical, cylindrical stack. These three stacks are grouped together, and are immediately adjacent to the turbine/HRSG stack. The sampling locations for all four stacks are accessed from a single platform.

2.2 Emission Source Description

The turbine/HRSG exhausts through a vertical, cylindrical stack that is 233 feet tall. The stack has an inside diameter of 16.5 feet (198.0 inches) and has a number of sampling ports, some of which are used for the unit's CEMS. Four of the ports that are available for use in testing are 90 degrees apart in the same horizontal plane, and are 4-inch pipe with flanges (150 psi rating type) and caps. The ports are 60 feet downstream from (or above) the stack dampers, and 100 feet upstream from the top of the stack. Access to the platform at 128 feet is by stairway to the top of the HRSG, then by ladder the last 60 feet.

A total of 24 sampling traverse points were located according to BAAQMD Method ST-18 (EPA Method 1). Six points were used in each of the four sampling ports.

Each auxiliary boiler exhausts through a vertical, cylindrical stack that is 233 feet tall. Each stack has an inside diameter of 6.0 feet (72.0 inches) and has two sampling ports. The ports are 90 degrees apart in the same horizontal plane, and are 4-inch pipe with flanges (150psi rating type) and caps. The ports are at least 60 feet downstream from (or above) the last disturbance in the flow, and 100 feet upstream from the top of the stack. Access to the ports is from the same large platform used for the turbine/HRSG stack

A total of 12 sampling traverse points were located according to BAAQMD Method ST-18 (EPA Method 1). Six points were used in each of the two sampling ports.

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MOJAVE air quality management district DESERT

Mojave Desert AQMD

14306 Park Avenue, Victorville, CA 92392-2310 (760) 245-1661

PERMIT TO OPERATE

B005329

Operation under this permit must be conducted in compliance with all information included with the initial application, initial permit condition, and conditions contained herein. The equipment must be maintained and kept in good operating condition at all times. This Permit to Operate or copy must be posted on or within 8 meters of equipment. If copy is posted, original must be maintained on site, available for inspection at all times.

EXPIRES LAST DAY OF: APRIL 2001

OWNER OR OPERATOR (1200)
Federal Bureau of Prisons - Victorville
13789 Air Base Road
Victorville, CA 92394

EQUIPMENT LOCATION: (02082)
Federal Bureau of Prisons - Victorville
13789 Air Base Road
Victorville, CA 92394

DESCRIPTION:

BOILER DUAL-FUEL consisting of:

Unilux dual fuel Boiler #1 (natural gas with diesel backup), Model Number ZF 2000 W, Serial Number 2220, equipped with flue gas recirculation and low NOx PowerFlame burners Model No. JNHPGA02-5H, Serial No. 02982021P, rated at 20 MMBtu/hr of heat input, providing water and space heating at the Federal Correctional Institution. Consumes up to 14 gal per hour of diesel fuel. Boiler #1 and Boiler #2 are served by three circulation pumps, which are included on this permit.

Capacity	Equipment Description
200.0	Unilux Boiler (20 MMBtu/hr)
1.9	Circulation Pump M3391-A11A260R102M
1.9	Circulation Pump M339A-A12A260R124M
1.9	Circulation Pump M339A-A11A260R102M
205.7	

CONDITIONS:

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
2. This equipment shall be installed, operated and maintained in strict accord with those recommendations of the manufacturer/supplier and/or sound engineering principles which produce the minimum emissions of contaminants.
3. This equipment shall not be operated without being exhausted into the selective catalytic reduction system with valid District permit C005333 fully functional.

Fee Schedule: 2(C) Rating: 205.7 SIC: 9223 SCC: 10300602 Location/UTM(Km): 467E/3825N

This permit does not authorize the emission of air contaminants in excess of those allowed by law, including Division 26 of the Health and Safety Code of the State of California and the Rules and Regulations of the District. This permit cannot be construed as permission to violate existing laws, ordinances, statutes or regulations of this or other governmental agencies. This permit must be renewed by the expiration date above. If billing for renewal fee required by Rule 301(c) is not received by expiration date above, please contact the District.

Federal Bureau of Prisons - Victorville
13777 Air Expressway Blvd
Victorville, CA 92394

BY: Copy
For: Charles L. Fryxell
Air Pollution Control Officer

DATE: 7/26/2000

CONDITIONS continued:

4. This equipment is subject to the federal NSPS codified at 40 CFR 60, Subparts A (General Provisions) and Dc (Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units). Compliance with all applicable provisions of these regulations is required (including the initial notification and quarterly reports to USEPA Region IX).

5. The o/o shall not use diesel fuel whose sulfur concentration exceeds 0.05% on a weight per weight basis in this equipment. This limit may be complied with through the fuel supplier's certification of sulfur content.

6. The operator shall maintain a log for this equipment, which, at a minimum, contains the information specified below. This log shall be maintained current and on-site for a minimum of two (2) years and shall be provided to District personnel on request:
   a. Daily fuel use of each type of fuel;
   b. Cumulative annual fuel use of each type of fuel; and
   c. Diesel fuel sulfur concentration certifications.

MOJAVE air quality management district DESERT

Mojave Desert AQMD

14306 Park Avenue, Victorville, CA 92392-2310 (760) 245-1661

PERMIT TO OPERATE

C005333

Operation under this permit must be conducted in compliance with all information included with the initial application,initial permit condition, and conditions contained herein. The equipment must be maintained and kept in good operating condition at all times. This Permit to Operate or copy must be posted on or within 8 meters of equipment. If copy is posted, original must be maintained on site, available for inspection at all times.

EXPIRES LAST DAY OF: APRIL 2001

OWNER OR OPERATOR (1200)
Federal Bureau of Prisons - Victorville
13289 Air Base Road
Victorville, CA 92394

EQUIPMENT LOCATION: (02082)
Federal Bureau of Prisons - Victorville
13289 Air Base Road
Victorville, CA 92394

DESCRIPTION:

SELECTIVE CATALYTIC NOX REDUCTION SYSTEM consisting of:

Emission control device employing the introduction of ammonia into boiler exhaust gas stream. System accepts exhaust gases from two boilers (B005329 and B005330). Manufactured by CRI Catalyst, Inc., item number 700160 01, with a 1 53 cubic meter reaction zone (catalyst unit weighs 3160 kg filled). System includes an Eclipse Combustion 2 MMBtu/hr (max) duct heater, Model BL14DABAR, Serial 00-2112 V1.1 for supplementary catalyst heating, and a 25 hp AirTech Fan Corp exhaust fan.

CONDITIONS:

1. Operation of this equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.
2. This equipment shall be installed, operated and maintained in strict accord with those recommendations of its manufacturer or supplier and/or sound engineering principles which produce the minimum emissions of contaminants.
3. This equipment shall be operated concurrently with the boilers issued valid permits B005329 and B005330.
4. Ammonia shall be injected whenever the selective catalytic reduction system has reached or exceeded the manufacturer's minimum recommended operating temperature except for periods of equipment malfunction. Except during periods of startup and shutdown, ammonia slip shall not exceed 5 ppmv dry at 3% oxygen. Compliance with this condition shall be demonstrated with CEMS and CERMS data.
5. Ammonia injection by this equipment in pounds per hour shall be recorded and maintained on site for a minimum of two (2) years and shall be provided to District personnel on request.
6. At no time shall this equipment emit NOx at a rate exceeding 5 ppmv dry at 3% oxygen. Compliance with this limit shall be demonstrated with CEMS and CERMS data.

Fee Schedule: 7(h) Rating: 1.0 SIC: 9223 SCC: 10300603 Location/UTM(Km): 467E/3825N

This permit does not authorize the emission of air contaminants in excess of those allowed by law, including Division 26 of the Health and Safety Code of the State of California and the Rules and Regulations of the District. This permit cannot be construed as permission to violate existing laws, ordinances, statutes or regulations of this or other governmental agencies. This permit must be renewed by the expiration date above. If billing for renewal fee required by Rule 301(c) is not received by expiration date above, please contact the District.

Federal Bureau of Prisons - Victorville
13777 Air Expressway Blvd
Victorville, CA 92394

BY: Copy

For: Charles L. Fryxell
Air Pollution Control Officer

DATE: 10/24/2000

CONDITIONS continued:

7. Emissions of NOx, O2 and ammonia slip from this equipment shall be monitored using a Continuous Emissions Monitoring System (CEMS). The stack gas flow rate shall be monitored using a Continuous Emission Rate Monitoring System (CERMS). The operator shall install, calibrate, maintain and operate these monitoring systems according to an District-approved monitoring plan and District Rule 218, and they shall be installed prior to operation. CEMS and CERMS shall meet the following acceptability testing requirements from 40 CFR 60 Appendix B:

   a. Performance Specification 2 for NOx;
   b. Performance Specification 3 for oxygen;
   c. Performance Specification 6 for stack gas flow rate; and,
   d. District approved procedure that is to be submitted by the o/o for ammonia.

8. This equipment does not require a regularly scheduled emission compliance test. However, emission compliance testing may be required at the discretion of the District.

9. Not later than 180 days after initial startup, the operator shall perform an initial compliance test. This test shall demonstrate that this equipment is capable of operation in compliance with conditions 4 and 6 and shall certify the CEMS and CERMS.

SOURCE TEST REPORT

Compliance Testing of Two Boilers Equipped with a Common SCR NO_X Reduction System

Prepared For:

Horiba Instruments.
17671 Armstrong Avenue
Irvine, California 92614

Test Dates:
October 12, and 13, 2000

Issue Date:
November 10, 2000

Project No.: c-7711-NH_3R1

Tested By:
Almega Environmental & Technical Services, Inc.
24412 South Main Street, Suite 106
Carson, CA 90745

Certification

As an authorized representative of Almega Environmental and Technical Services, Inc., I certify that, to the best of my knowledge, the data and information presented in this report is true, accurate, and complete.

Prepared By: Michael J. Rohál, Project Manager — 11/10/00 Date

Certified By: Mike Fukuda, Director of Technical Services — 11/10/00 Date

1.0 EXECUTIVE SUMMARY

Facility Permit Holder:	Federal Bureau of Prisons – Victorville
Equipment Type:	Two (2) Natural Gas Fired Boilers Equipped with a common SCR NOx-reduction system
Equipment Location:	Federal Correctional Institution at Victorville 13289 Air Base Road Victorville, CA 92394
Facility I.D. No.:	1200
Authority To Construct No.:	C0053330
Test Objective:	To demonstrate compliance with the Authority To Construct No. C005330
Test Dates:	October 12, and 13, 2000
Test To Be Performed By:	Almega Environmental and Technical Services, Inc.
Testing Personnel	**Mike Rohall** – Team Leader **Rafik Beshai** – Test Engineer
Facility Contact:	J. Scott Ashliman FCI Victorville 17603 Cobalt Road, Victorville, CA 92394 tel: (760) 530-0250
Testing Firm Contact:	Mike Fukuda Director of Technical Services Almega Environmental & Technical Services, Inc. 24412 South Main Street, Suite 106, Carson, CA 90745 tel: (310) 834-8996
MDAQMD Contact:	**James N. Lehmann** *Air Quality Engineer III* (706) 245-1661 ext. 1864
Regulatory Agency:	Mojave Desert Air Quality Management District (MDAQMD)

2.0 SUMMARY OF TEST RESULTS

Table 2-1 summarizes the results for compliance testing of the subject source. Testing for NO_X, O_2, NH_3, and stack gas flow rate was performed as follows:

- Three tests were performed to measure NO_X, O_2, and stack gas flow rate at the "High-fire" condition. Two tests were performed on October 12 and the third test was performed on October 13.
- Four tests were performed to measure NH3. Two tests, including O_2, were performed at the High-fire condition. Two additional tests were performed at the "Low-fire" and "Mid-fire" conditions.
- NO_X and O_2 data for the Low-fire and Mid-fire tests were provided by the Facility's CEMS.

NO_X and NH_3 emissions met the compliance limit specified in the Authority to Construct.

TABLE 2-1. SUMMARY OF RESULTS

PARAMETER	units	C-1	C-2	C-3	NH3-2	NH3-3	Average	Compliance Limit
Test Condition:		High	High	High	Low	Mid		
Test Date:	M/D	12-Oct	12-Oct	13-Oct	13-Oct	13-Oct		
Start Time:	hh:mm	14:36	15:58	15:44	17:05	18:27		
End Time:	hh:mm	15:36	16:58	16:44	18:05	19:27		
Oxygen Concentration	%	8.78	9.02	9.01	6.45 *	6.52 *	**7.30**	
Moisture Content	%	11.8	11.5	11.5			**11.6**	
NOx Emissions								
NOx Concentration	ppmv	2.97	2.93	2.57	2.54 *	3.30 *	**2.89**	
corrected to 3% O2	ppmv	4.39	4.41	3.87	3.14 *	4.10 *	**3.82**	5.0 ppmv
NOx Emission Rate	lb/hr	0.048	0.048	0.043			**0.046**	
Ammonia Emissions	ppmv							
NH3 Concentration		0.12		0.17**	0.29	0.14	**0.18**	
corrected to 3% O2	ppmv	0.18		0.26**	0.36	0.17	**0.24**	5.0 ppmv
Stack Gas Flow Rate								
Dry Basis	DSCFM	2,257	2,275	2,306			**2279**	
as measured	ACFM	4,271	4317	4,310			**4299**	

NOTES: * Data provided by Facility CEMS (see Appendix F).
** Additional NH3 Test requested by CRI, result excluded from average.

CRI Catalyst CEMS Month Summary by Day Report - Permit 8836

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Daily Totals	Raw NOx Concen. ppm	Nox Emiss. #	Stack Flow MDSCFM	O2 Pct	20MM BTU/HR NAT GAS SCFM	NH3 Slip	HRS	16MM BTU/HR NAT GAS SCFM	3 Hr Av. NOx Corr	Hrs	NOx Corr 3% O2	NH3 Inj. #/HR	Stack Temp DegF.	NOx Qual Time	Oper. Time
01/03/01	3.06	0.55	1,222.08	5.21	74.53	0.00	0.00	262.11	3.49	23.70	3.49	.1	88.9	24	24
01/03/02	3.11	0.56	1,237.38	5.26	69.03	0.00	0.00	257.33	3.56	23.67	3.56	.1	90.3	24	24
01/03/03	3.07	0.56	1,165.80	6.75	55.23	0.00	0.01	281.81	3.55	23.11	3.51	.1	91.0	24	24
01/03/04	3.02	0.51	1,133.39	5.32	82.49	1.11	0.00	478.04	3.40	23.77	3.43	1	96.7	24	24
01/03/05	3.04	0.49	1,064.82	5.07	91.13	1.25	0.35	465.58	3.44	23.48	3.44	.1	97.1	24	24
01/03/06	2.87	0.54	1,156.72	6.39	69.14	0.00	0.03	424.69	3.33	22.57	3.33	.1	92.0	23	24
01/03/07	2.88	0.53	1,148.22	6.16	68.84	0.39	0.00	432.57	3.38	23.67	3.34	.1	89.2	24	24
01/03/08	3.08	0.48	986.48	5.16	76.91	0.66	0.08	437.50	3.52	23.85	3.50	.1	95.6	24	24
01/03/09	3.12	0.58	1,205.84	5.65	62.39	0.82	0.00	438.49	3.64	23.85	3.66	.1	97.4	24	24
01/03/10	2.88	0.64	1,314.27	7.34	105.13	0.00	0.06	361.98	3.52	21.05	3.41	.1	93.6	24	24
01/03/11	3.27	0.61	1,263.67	5.43	88.38	0.48	0.12	424.46	3.77	23.78	3.78	.1	92.9	24	24
01/03/12	3.70	0.69	1,213.32	5.31	92.84	1.05	0.39	430.01	4.18	23.85	4.24	.1	91.0	24	24
01/03/13	3.89	0.62	1,069.07	6.10	76.18	0.00	0.03	374.00	4.62	21.85	4.52	.1	94.5	24	24
01/03/14	4.50	0.65	997.62	5.65	63.74	[illegible]	0.29	569.21	5.36	23.54	5.23	.2	92.7	24	24
01/03/15	3.60	0.53	991.93	5.35	89.16	0.96	0.23	426.58	4.18	23.75	4.14	.1	94.2	24	24
01/03/16	2.91	0.46	1,072.72	5.99	573.41	0.00	0.37	396.21	3.50	22.16	3.42	.1	159.5	24	24
01/03/17	2.90	0.41	871.06	6.99	1,250.76	0.91	1.00	456.83	3.47	23.87	3.48	.1	260.0	24	24
01/03/18	2.77	0.39	879.54	7.09	904.48	0.26	0.94	456.42	3.35	21.98	3.33	.1	246.8	24	24
01/03/19	2.57	0.38	840.84	7.88	1,002.51	0.00	0.88	429.17	3.40	20.67	3.20	.1	237.9	22	24
01/03/20	2.92	0.45	823.47	7.95	770.27	1.08	0.88	520.83	3.64	23.00	3.57	.1	235.6	23	24
01/03/21	3.07	0.46	892.99	7.50	879.38	0.00	0.92	483.80	3.86	23.22	3.80	.1	245.0	24	24
01/03/22	3.21	0.30	989.58	6.17	849.51	0.78	1.00	272.92	3.76	13.86	3.90	.1	260.3	14	24
2001	Month totals to date														
	3.16 average	11.39 total	1,074.58 average	6.08 average	7,195.44 total	17.01 total	8 total	9,060.54 total	81.94 total	498 total	3.69 average	0.11 average		514 total	528 total

Facility

CRI Catalyst CEMS Month Summary by Day Report - Permit 8836

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Daily Totals	Raw NOx Concen. ppm	Nox Emiss. #	Stack Flow #DSCFM	O2 Pct	20MM BTU/HR NAT GAS SCFM	NH3 Slip	HRS	16MM BTU/HR NAT GAS SCFM	3 Hr Av. NOx Corr	Hrs	NOx Corr 3% O2	NH3 Inj. #/HR	Stack Temp DegF.	NOx Qual Time	Oper. Time
01/02/01	3.00	0.87	1,441.72	6.39	1,337.64	0.00	1.00	407.08	3.71	23.90	3.71	1	298.9	24	24
01/02/02	3.01	0.75	1,579.53	8.83	1,608.59	0.00	1.00	375.65	3.83	23.83	3.83	1	302.9	24	24
01/02/03	3.01	0.52	1,196.56	6.58	1,245.62	0.00	1.00	421.44	3.71	23.80	3.71	1	274.2	24	24
01/02/04	2.91	0.49	1,017.09	8.87	1,106.91	0.00	0.96	436.34	3.57	23.82	3.56	1	257.2	24	24
01/02/05	2.81	0.47	978.31	7.77	1,005.08	0.00	0.91	453.33	3.45	23.80	3.47	.1	249.3	23	24
01/02/06	2.90	0.45	944.39	7.19	966.56	0.00	0.95	448.51	3.64	23.82	3.62	.1	248.6	24	24
01/02/07	3.01	0.72	1,627.96	6.07	1,592.74	0.00	1.00	373.35	3.63	23.90	3.64	1	311.1	24	24
01/02/08	3.01	0.87	1,912.44	6.43	1,806.32	0.00	1.00	352.34	3.74	23.90	3.74	.1	323.2	24	24
01/02/09	3.01	0.79	1,767.44	6.27	1,556.55	0.00	1.00	378.08	3.68	23.90	3.69	.1	315.9	24	24
01/02/10	3.01	0.79	1,712.48	6.17	1,378.81	0.00	1.00	390.80	3.65	23.86	3.66	.1	312.1	24	24
01/02/11	2.99	0.78	1,708.80	6.17	946.10	0.00	0.67	377.60	3.63	23.72	3.63	.1	238.1	24	24
01/02/12	2.90	0.76	1,694.30	6.40	78.82	0.00	0.00	357.20	3.49	23.66	3.48	1	90.5	24	24
01/02/13	3.01	0.70	1,569.10	5.70	53.09	0.00	0.00	367.61	3.53	23.88	3.54	1	93.9	24	24
01/02/14	3.02	0.77	1,607.41	5.74	43.08	0.00	0.00	373.61	3.53	23.82	3.52	.1	86.9	24	24
01/02/15	2.93	0.68	1,508.62	5.88	54.06	0.00	0.00	369.81	3.44	23.24	3.42	.1	86.9	24	24
01/02/16	3.11	0.63	1,360.13	5.31	67.73	0.00	0.02	406.28	3.52	23.86	3.56	.1	89.7	24	24
01/02/17	3.04	0.55	1,250.94	5.33	69.07	0.00	0.00	384.76	3.51	23.88	3.50	.1	91.0	24	24
01/02/18	2.98	0.57	1,245.67	5.76	92.30	0.00	0.15	390.98	3.47	23.59	3.46	.1	94.0	24	24
01/02/19	2.88	0.62	1,351.65	6.19	125.32	0.00	0.13	335.65	3.39	23.11	3.39	.1	100.2	24	24
01/02/20	2.93	0.58	1,311.65	5.87	88.06	0.00	0.03	229.26	3.37	22.86	3.37	.1	95.2	24	24
01/02/21	3.04	0.63	1,199.00	5.33	70.06	0.00	0.09	230.53	3.49	23.87	3.49	.1	97.9	24	24
01/02/22	3.88	0.58	825.61	8.43	22.17	0.00	0.00	78.71	4.62	8.12	4.45	.1	34.7	18	23
01/02/23	3.17	0.71	1,440.12	5.44	32.84	0.64	0.00	223.58	3.65	12.92	3.67	1	50.9	24	24
01/02/24	3.02	0.68	1,541.76	5.56	58.26	0.88	0.00	430.21	3.51	23.87	3.52	.1	99.9	24	24
01/02/25	3.36	0.60	1,218.21	5.61	126.25	0.00	0.04	367.16	3.96	22.29	3.94	.1	100.8	24	24
01/02/26	3.14	0.75	1,498.67	5.54	59.90	0.00	0.00	254.38	3.65	23.83	3.67	.1	85.3	24	24
01/02/27	3.04	0.66	1,358.68	5.42	50.19	0.00	0.00	256.87	3.51	23.85	3.52	.1	88.5	24	24
01/02/28	3.08	0.63	1,343.87	5.44	51.70	0.00	0.00	258.23	3.56	23.74	3.57	.	89.8	24	24
2001	Month totals to date														
	3.04 average	18.30 total	1,400.43 average	6.13 average	15,693.82 total	1.52 total	11 total	9,729.35 total	101.44 total	637 total	3.62 average	0.10 average		665 total	671 total

Facility

CRI Catalyst CEMS Month Summary by Day Report - Permit 8836

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Daily Totals	Raw NOx Concen. ppm	Nox Emiss. #	Stack Flow MDSCFM	O2 Pct	20MM BTU/HR NAT GAS SCFM	NH3 Slip	HRS	16MM BTU/HR NAT GAS SCFM	3 Hr Av. NOx Corr	Hrs	NOx Corr 3% O2	NH3 Inj. #/HR	Stack Temp DegF.	NOx Qual Time	Oper. Time
01/01/01	2.81	7.63	1,203.72	5.92	52.33	0.00	0.00	560.77	76.34	20.84	3.27	23.4	95.2	24	24
01/01/02	3.52	8.74	1,169.16	5.42	49.30	0.00	0.00	475.30	94.91	22.28	4.04	19.8	92.9	24	24
01/01/03	3.57	9.62	1,159.15	5.51	48.77	0.00	0.00	431.29	101.38	21.20	4.20	18.0	91.4	24	24
01/01/04	3.11	8.13	1,153.87	5.54	63.37	0.00	0.00	474.53	89.77	17.81	3.64	19.8	91.0	24	24
01/01/05	3.01	8.16	1,182.00	5.67	75.87	0.00	0.00	496.63	85.94	19.15	3.57	20.7	90.4	24	24
01/01/06	2.65	4.90	833.68	4.20	80.22	0.00	0.00	561.67	68.64	14.30	2.82	23.4	92.9	24	24
01/01/07	2.62	5.08	894.78	3.94	74.05	0.00	0.00	386.47	63.54	12.48	2.75	16.1	92.1	24	24
01/01/08	2.06	5.23	1,144.80	4.41	145.35	0.00	1.10	251.02	53.13	5.18	2.22	10.5	101.2	24	24
01/01/09	2.81	7.02	1,002.98	7.25	253.91	0.00	0.21	593.13	3.12	16.40	3.01	1.3	127.1	20	24
01/01/10	2.98	10.05	1,507.51	3.90	70.42	0.00	0.00	814.72	3.14	23.90	3.16	.1	87.5	24	24
01/01/11	3.00	10.25	1,585.38	4.93	56.42	0.00	0.00	824.42	3.36	23.90	3.37	.1	85.6	24	24
01/01/12	3.01	0.72	1,552.03	5.24	55.76	0.00	0.00	861.22	3.44	23.90	3.45	.1	86.8	24	24
01/01/13	2.93	0.67	1,428.38	5.79	362.13	0.00	0.23	868.05	3.44	23.40	3.46	.1	139.9	24	24
01/01/14	3.06	0.68	1,481.60	6.55	1,514.57	0.00	1.00	808.40	3.86	20.07	3.82	.1	312.1	24	24
01/01/15	3.01	0.77	1,653.76	6.56	1,705.43	0.00	1.00	850.41	3.76	23.85	3.75	.1	326.3	24	24
01/01/16	3.02	0.73	1,597.86	6.36	1,575.68	0.00	1.00	839.67	3.71	23.88	3.73	.1	321.2	24	24
01/01/17	3.60	0.87	1,602.97	6.50	1,588.62	0.00	1.00	703.67	4.37	23.97	4.44	.1	319.1	24	24
01/01/18	3.02	0.77	1,556.62	6.53	1,651.45	0.00	1.00	335.04	3.80	23.86	3.76	.1	315.1	24	24
01/01/19	3.01	0.71	1,538.71	6.53	1,578.14	0.00	1.00	367.05	3.75	23.88	3.75	.1	312.3	24	24
01/01/20	3.00	0.62	1,371.30	6.37	1,423.58	0.00	1.00	367.54	3.69	23.84	3.70	.1	298.9	24	24
01/01/21	3.01	0.60	1,355.26	6.50	1,365.30	0.00	1.00	384.72	3.73	23.88	3.74	.1	296.6	24	24
01/01/22	2.91	0.61	1,342.00	7.06	1,343.78	0.00	0.97	375.14	3.62	23.62	3.62	.1	291.2	24	24
01/01/23	3.01	0.56	1,319.16	6.43	1,346.53	0.00	1.00	373.92	3.72	23.78	3.73	.1	291.8	24	24
01/01/24	2.99	0.67	1,393.49	6.59	1,349.86	0.00	1.00	374.36	3.75	23.81	3.75	1	299.1	24	24
01/01/25	3.01	0.69	1,488.93	6.50	1,452.86	0.00	1.00	383.35	3.74	23.87	3.75	.1	308.9	24	24
01/01/26	2.97	0.03	1,519.98	6.53	61.83	0.00	1.00	15.56	3.67	1.00	3.70	.1	314.0	1	24
01/01/27	2.97	0.75	1,637.14	6.81	1,546.60	0.00	0.98	310.67	3.69	22.99	3.69	1	319.1	24	24
01/01/28	3.00	0.73	1,563.98	6.29	1,483.82	0.00	1.00	214.42	3.87	23.87	3.67	.1	313.0	24	24
01/01/29	2.93	0.71	1,554.42	6.58	1,465.89	0.00	0.99	251.38	3.61	23.34	3.62	.1	310.6	24	24
01/01/30	3.01	0.70	1,527.35	6.43	1,382.14	0.00	1.00	390.19	3.72	23.87	3.73	1	308.1	24	24
01/01/31	3.16	0.74	1,527.19	5.71	1,432.73	0.00	1.00	376.93	4.05	23.32	3.94	.1	307.4	24	24
Month totals to date															
2001	3.09 average	98.14 total	1,428.31 average	6.19 average	26,656.71 total	0.00 total	19 total	15,321.84 total	718.06 total	645 total	3.70 average	5.17 average		717 total	744 total

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Gas Turbine World

Low-temperature SCR expedites plant retrofits for NOx reduction

Low-temperature SCR systems, installed at the tail end of heat recovery boilers, can be retrofitted to existing cogeneration plants with a minimum of downtime.

Kinetics Technology International in Concord, Calif. is retrofitting gas turbine cogeneration installations with low temperature selective catalytic reduction (SCR) systems to achieve very low NOx emissions at considerably lower modification costs than retrofits with conventional SCR. Major features:

- **SCR Design.** Temperature window of 325 to 680°F, pressure drops of around 0.5 to 2 inches water, and flow rates from 10,000 lb/hr to over 1,000,000 lb/hr.

- **Effectiveness.** Routine gas turbine retrofit projects are operating with 90-93% NOx removal efficiencies on natural gas and refinery fuels.

- **Installed Cost.** Total installed cost (design, equipment, labor) is said to run 20-30% less than that of a conventional SCR retrofit – with significantly less downtime.

- **Projects.** Since 1995, low-temp SCR has been retrofitted to Allison 501, Turbo Power FT4, Gen Electric Fr 5 and Westinghouse 191 gas turbine installations.

Conventional SCRs usually require a narrow temperature band of 550-725°F (288-385°C) or, for higher temperature applications, 800-1100°F (427-593°C) in which to operate. Meeting those needs for a gas turbine based system typically calls for locating the SCR units within the heat recovery steam generator (HRSG).

Retrofitting a cogeneration plant with a conventional system calls for splitting the HRSG apart (to make room for the SCR elements) or relocating heating coils. The low-temp SCR system can be simply located at the tail end of the HRSG or exhaust ducting.

KTI's experience with this technology goes back to the late 1980s with the installation of a Shell DeNOx System for an ethylene plant in Germany. "Subsequently," says KTI Concord's General Manager Tom Gilmore, "we realized that being able to locate an SCR system at the tail end of an HRSG (or furnace convection section) would considerably reduce installation and retrofit costs as well as plant downtime."

To commercialize this concept, KTI arranged for a license agreement whereby Shell provides low-temp catalyst modules for a de-NOx system and KTI designs and markets complete packages for industry installations.

The first non-gas turbine project in the U.S. was in 1992 for two small furnaces at a Chevron refinery in Los Angeles which had a flow rate of 60,940 lb/hr and 390°F flue gas temperature. NOx was reduced by some 90 percent, says Gilmore.

The first gas turbine retrofits were done in 1995 at three refinery sites, two in California and one in Texas. Flow gas temperatures ranged from 325 to 375°F, with the lowest of those found at the Texas cogeneration plant powered by an Allison 501-KB5 machine. Since then, gas turbine retrofit agreements have been arranged for six other units, mostly in the San Francisco Area.

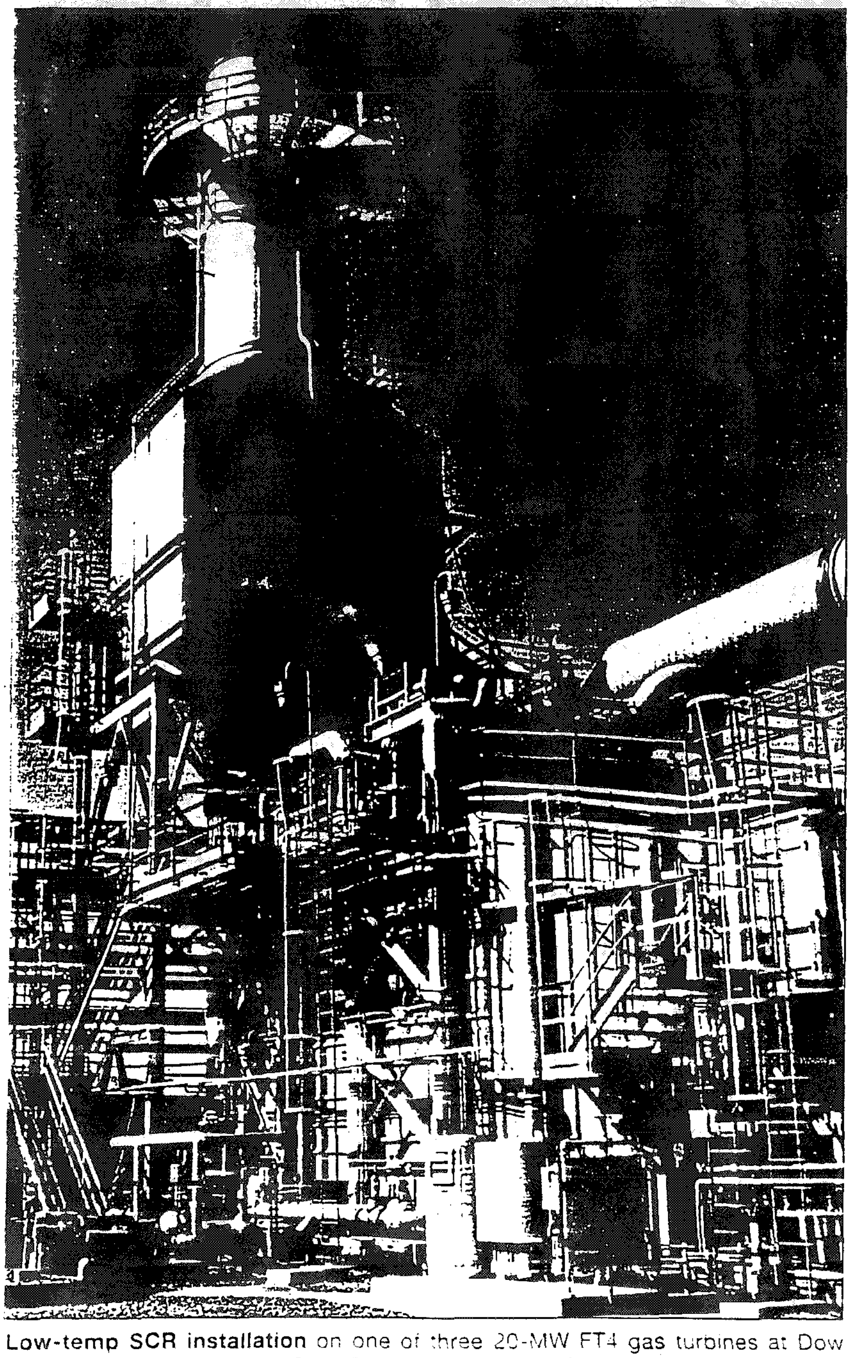
Sintering concern

Having to install conventional SCR inside an HRSG restricts the amount of duct firing that can be tolerated to raise extra steam. If faced with that problem, you have two choices, says KTI. You can either limit steam production to avoid sintering, or increase the firing to get more steam output and accept the sintering.

Low-temp SCR systems at the tail end of gas turbine HRSG units don't have this problem. With or without supplementary firing, says Gregory Croce, manager of engineering at KTI, the "buffering" effect HRSG operation has on stack temperature results in relatively constant flue gas temperatures.

"Since our system can operate between 325 and 680°F (163 to 360°C) there is no concern about potential catalyst damage due to sintering. It allows you to fire duct burners harder whenever you need more process steam for plant operations."

According to Croce, the potential for ammonium salt formation is another concern for SCR installations "With any SCR catalyst, a fundamental issue is ammonium salts. If you have sulfur trioxide (SO_3), ammonia, and water, you will have chemical reactions producing ammonium bisulfate or ammonium sulfate.



Low-temp SCR installation on one of three 20-MW FT4 gas turbines at Dow Chemical plant in Pittsburg, Calif. Retrofitted to bring NOx emissions down below 9 ppmv required by the Air Quality Management District. SCR units, operating at 375°F flue gas temperature, achieve 95% NOx reduction efficiency.

"When you have sulfur dioxide (SO_2) in flue gas, a small amount is [illegible] process. High temperature catalyst will also convert more SO_2 to SO_3 than a low temperature one. Over a [illegible] cause a catalyst to deteriorate. Salt formation is a function of temperature and reactant compositions. The com- [illegible] cipitate out and they find that on economizer tubes in the HRSG."

Since ammonium salt precipitation [illegible] low-temp SCR design considers flue gas SO_3 content in relation to temperature as a basic design parameter. With the tail-end location of the unit and ammonia injection downstream of the HRSG, low temperatures like those encountered in the economizer section are avoided.

Salt not a problem

As long as the flue gas is low in sulfur, and relatively free of of dust particles, Croce says that salt formation is not a problem for low-temp SCR installations. On one project, KTI was called in to retrofit a refinery system equipped with conventional SCR that did have a salt problem. "Whenever there was a shutdown, they had to go in and shovel out large amounts of salts. But, since we installed low-temp SCR, the problem has been eliminated."

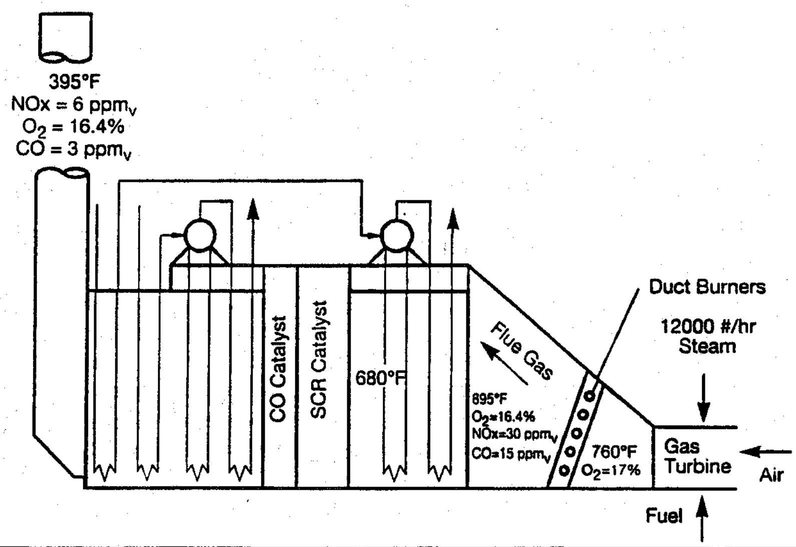
Low sulfur content becomes a concern for gas turbine plants which normally burn natural gas but may operate from time to time on backup liquid fuel. "We can handle burning #6 fuel oil for a couple of weeks," Croce explains, "but we cannot accommodate heavy exposure to oil for an extended period of time."

The prime incentive for retrofit interest in the San Francisco Bay area is the Reg 9 Rule 9 requirements passed by the Bay Area Air Quality Management District which mandated that facilities in its district achieve certain minimum NOx emissions by January 1997.

The rule permits operation of gas turbines rated 10 MW or higher to meet either of two emission levels depending on the NOx reduction technique adopted. One option is 15 ppmvd using dry low NOx combustors, water injection or steam injection. The other calls for 9 ppmvd or less based on use of either conventional SCR or low-temp SCR for NOx removal.

In one case, for a Frame 5 gas turbine site in Benicia, studies concluded that SCR in general would be more [illegible] NOx or injection. This was a vertical exhaust gas turbine installation so that while it was not practical to retrofit conven- [illegible] temp SCR [illegible] tem readily fit the bill.

Conventional SCR installation. Original HRSG design for the cogeneration plant powered by three 16-MW Westinghouse W-191 gas turbines exhausting into supplementary-fired boilers. Each power package operated with a combination of steam injection for the gas turbine and conventional SCR catalyst in the middle of the HRSG to reduce NOx, plus a CO catalyst behind the SCR to reduce CO emissions resulting from the steam injection. Supplementary firing was restricted by a 680°F limit on the SCR catalyst.



The gas turbine's exhaust gas temperature of 375°F was well within the catalyst performance range. And the SCR could be installed in the vertical stack. Since the retrofit, the plant has been operating at NOx output levels of under 9 ppmvd with less than 5 ppm ammonia slip.

W-191 retrofit design

A San Francisco refinery cogeneration plant evaluated by KTI for retrofit was powered by three Westinghouse W-191 EconoPac turbines rated 16 MW each. The plant operated with a combination of steam injection and conventional SCR catalyst located in the middle of the HRSG to achieve an emission level of 25 ppm NOx. It also used a CO catalyst placed behind the SCR to reduce CO emissions resulting from the steam injection.

There were problems with the plant. One, a temperature limitation of 680°F on the SCR catalyst, restricted duct burner firing and limited HRSG steam output. Another was high sulfur content in the refinery fuel gas that was converted by both the SCR and CO catalysts into SO_3.

This, in turn, resulted in precipitation of ammonium salts on economizer coils thereby further reducing steam output. In addition, the 12,000 lb/hr of steam injection needed for NOx control could have been more profitably used for process needs.

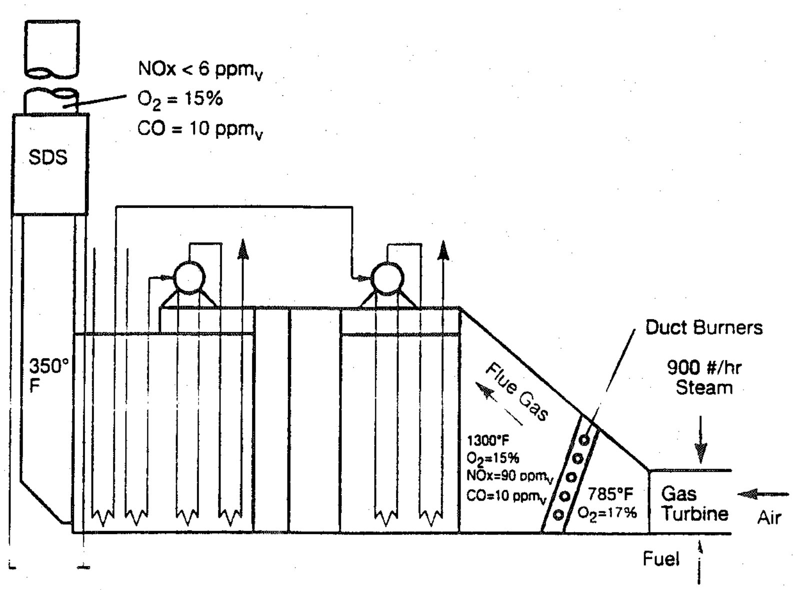
The first option studied was to retrofit the gas turbines with dry low-NOx combustors and remove the existing SCR and CO catalysts. But DLN combustors were not available at the time. And, even if they were, they would not be able to handle the high level of hydrogen content in the refinery gas being burned as fuel.

Engineering then looked into the feasibility of increasing the steam injection flow rate for NOx control. But this would incur higher operating costs and would not achieve 9 ppm with the original SCR.

Adding catalyst to that SCR was considered, but there wasn't space for more catalyst and the retrofit costs to make such space would be prohibitive. The data also indicated there would be too high a pressure drop across the reconfigured system and ammonium salt deposition remained a problem.

Thus, by a process of elimination, low-temp SCR won out as the most

Retrofit HRSG modification. Conventional SCR and CO catalyst sections were removed, low-temperature SCR system installed at the tail end of each HRSG in the vertical exhaust duct, and steam injection rate reduced for gas turbine NOx control. Removing the restriction on HRSG supplementary firing allows the facility to produce 130,000 lb/hr more process steam. Reducing the amount used for NOx control makes another 33,000 lb/hr steam available.



Low-Temperature SCR Retrofit Projects
Starting in 1995, KTI has retrofitted low-temperature SCR systems to both heavy industrial and aeroderivative gas turbine cogeneration plant installations to achieve 90-95% NOx removal efficiencies

Year	Location	Gas Turbine Model	Treated Flow	NOx Removal	Flow Temp
1995	San Francisco, CA	Westinghouse W-191 16 MW each (3 units)	1,052,000 lb/hr	93 per cent	360°F
1995	Benicia, CA	General Electric Fr5 14 MW rating	710,000 lb/hr	91 per cent	375°F
1995	Pasadena, TX	Allison 501-KB5 4 MW rating	135,000 lb/hr	90 per cent	325°F
1997	Pittsburg, CA	Turbo Power FT4 20 MW each (3 units)	1,000,000 lb/hr	95 per cent	375°F

attractive economic and technical solution. Redesign involved deleting the SCR and CO catalysts and repositioning the ammonia injection grid to avoid salt deposition on the tail-end mounted retrofit installation.

To minimize downtime that would interrupt plant productivity, all the civil and foundation work for support of the retrofit was done during normal operations. The low-temp SCR system was then installed during a scheduled gas turbine maintenance shutdown period of three weeks.

Less pressure drop

With the new alignment, overall system pressure drop was reduced to 0.5 from 3.5 inches water – which resulted in a power generation increase of 150 kW per gas turbine.

The greatly reduced steam injection rate for the retrofit made an additional 33,000 lb/hr of steam available for process use. And eliminating the duct firing limitation permitted the HRSGs to generate 150,000 lb/hr more steam.

KTI reports that annualizing the engineering, procurement and construction capital cost, plus O&M cost, over a 5-year life for the low-temp SCR retrofit yields a cost effectiveness (value) of $2480 per ton of NOx removed.

This contrasts with refinery project "cost effectiveness values" of $4000 to $8000 per ton NOx removed for ultra low NOx burners and $10,000 to $12,000 per ton NOx removed for conventional SCRs installed on existing refinery furnaces.

Another study for a project involving three Turbo Power gas turbines at a Bay Area chemical plant also showed low-temp SCR as an attractive option for NOx removal. The HRSGs for this application are unique in that the plant generally has more demand for power than steam.

During operation, where steam demand is low and power demand is high, gas turbine exhaust was diverted to the atmosphere via a vent stack located upstream of the HRSG instead of venting steam. Frequent use of the vent stack, however, contributed significantly to overall plant emissions.

Eliminating the vent stack as an emission source, while maintaining the existing steam control system, was set as a basic design guideline for the SCR retrofit. The answer was a flow bypass arrangement which can bypass the same amount of flue gas previously vented for controlling steam production.

That bypass flow is then mixed with flue gas exiting the HRSG just upstream of the low-temp SCR so as to remove NOx from both streams. There is a carefully sized flue gas distribution grid downstream of the HRSG to ensure an even temperature pattern entering the SCR inlet which contributes to a 93.4% NOx removal efficiency.

At minimum bypass conditions, the inlet temperature into the SCR is 375°F. At maximum bypass conditions, occurring during minimum steam production from the HRSG, the temperature can rise to 500°F. No problem, since that temperature range is well within the retrofit SCR's operating window.

Living in the bubble

Gilmore notes that low-temp SCR technology can play an important role in satisfying "bubble based" rules beginning to affect U.S. West Coast operations which require that the emissions from an entire plant be brought below a certain limit at the edges of the envelope.

In the Bay Area, that limit is 0.033 lb NOx per million BTU fired which results in a value of around 27 ppm for the bubble. Two options are open to plant operators. One is to reduce NOx output from various plant units; the other is to buy emission credits.

Take a hypothetical 50-furnace plant as an example. Retrofitting low NOx burners to all 50 furnaces would work. However, a more cost effective approach might be to only reduce emissions for the larger sources of emissions.

"It is quite conceivable," Gilmore maintains, "that you could retrofit low-temp SCRs on the four biggest emitters; low NOx burners on thirteen of the smaller furnaces; and leave the remaining units alone – and still meet the overall 27 ppm requirement at a much total lower cost." ■

Reprinted from Gas Turbine World, July/August 1997
by The Reprint Dept. 800-259-0570

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Engelhard Experience List
CO Oxidation Catalysts on Gas Turbines

Location	Gas Turbine Type	Number of Turbines	Temp. °F	Flow #/sec.	Design Conv. (%)	Start-Up
Conoco, NM	RB211	3	645	139	90	10/86
Mobil, IL	LM-2500	1	519	160	42	11/87
Chevron, CA	Frame 6	2	902	305	90	12/87
Unocal, CA	West 251	1	710	375	82	6/88
PSE, CA	LM-5000	1	750	351	90	6/88
Chevron, CA	LM-2500	2	720	154	80	7/88
Midsun, CA	LM-2500	1	936	152	80	7/88
Pitchess, CA	LM-2500	1	858	150	83	9/88
PSE, CA	LM-2500	6	890	162	82	2/89
Gilroy, CA	Frame 7	1	535	695	80	2/89
Basic Am., CA	Boiler	1	533	33	90	2/89
Wilmington, CA (G)	Frame 7E	1	990	671	85	3/89
Kenilworth, NJ (G)	LM-2500	1	820	172	80	3/89
San Diego, CA (G)	LM-5000	1	—	300	90	5/89
San Diego, CA (G)	LM-2500	1	—	148	90	6/89
Arco, CA	LM-2500	1	920	149	84	6/89
Bethpage, NY (G)	LM-2500	2	—	148	90	7/89
Ice Haus II, CA	LM-5000	1	792	303	80	9/89
PSE, CA	LM-5000	1	760	350	60	2/90
Houston, TX (G)	W-191	2	775	267	85	6/90
Arco, CA	LM-2500	1	920	149	84	7/90
Texas City, TX (G)	W-191	2	775	267	85	8/90
City of Anaheim, CA	LM-5000	1	900	333	82	12/90
Eagle Point, NJ	Frame 7	2	580	750	75	1/91
PSE,CA	LM-5000	1	760	350	80	2/91
PSE,CA	LM-5000	1	760	350	80	6/91
Northeast Twp. PA (G)	LM-5000	2	546	286	90	7/91
Syracuse, NY (G)	LM-5000	2	550	286	90	9/91
Binghampton, NY	LM-5000	1	—	300	90	9/91
Nevada	LM-2500	6	589	148	90	10/91
PSE, CA	LM-5000	1	760	350	80	11/91
Chevron, CA	BBC-8	2	930	410	90	1/92
Bakersfield, CA (G)	LM-5000	1	660	306	80	4/92
Los Angeles,CA	LM-1600	2	959	107	90	6/92
Houston, TX	RR	1	1100	259	95	8/92
Newark Bay, NJ	W-251	2	590	422	90	12/92
Washington State	Frame 7	1	625	669	80	1Q/93

CO Oxidation Catalysts on Gas Turbines (cont'd)

Engelhard Experience List
CO Oxidation Catalysts on Gas Turbines

Location	Gas Turbine Type	Number of Turbines	Temp. °F	Flow #/sec.	Design Conv. (%)	Start-Up
PSEG-Burlington, NJ (G)	P & W-FT8 Twin Pack	8 Turbines / 4 HRSG's	678	427	90	3/94
San Francisco, CA	LM-2500	1	900	157	80	5/93
Los Angeles, CA (G)	Frame 7E	2	971	687	92	7/93
Farmington, NM (G)	ABB 10B	1	983	154	87	11/93
Plattsburg, NY (G)	Frame 7EA	2	705	663	90	11/93
Mont Belvieu, TX (G)	Solar Mars	1	980	85	95	4/94
Tupman, CA (G)	LM-2500	2	—	153	90	7/94
Lausanne, Switzerland	ABB	1	900	60	80	8/94
Cambridge, MA (G)	ABB GT 10	1	604-879	184	98	8/94
Elk Grove, CA (G)	LM-6000	1	—	303	90	8/94
Bear Mountain, CA	LM-5000	1	880	350	80	4/95
Ceres, CA	LM-5000	1	750	342	88	4/95
Lodi, CA	LM-5000	1	750	342	88	4/95
Sussex, NJ (G)	Solar Centaur	1	650-980	37	91	7/95
Martinez, CA (G)	LM-6000	2	560	343	90	8/95
Ludington, MI (G)	Frame 7EA	1	876	673	80	8/95
Princeton, NJ (G)	LM-1600	1	—	—	90	8/95
Solvay, NY (G)	LM-5000	1	—	300	90	8/95
Tacoma, WA (G)	Frame 7F	1	923	1035	85	8/95
Fresno, CA	P&W FT4A9	1	860	314	80	11/95
Brooklyn, NY (G)	Siemens V84.2	2	1027	750	98	12/95
Sacramento, CA (G)	LM-6000	1	938	290	90	3/96
Sacramento, CA (G)	LM-2500	1	604	162	92	4/96
Greeley, CO (G)	LM-6000	1	620	247	80	1/96
Cottage Grove, MN (G)	W-501F	1	655	1079	90	7/96
Austria (G)	MAN GHH FT8	1	878	197	70	8/96
Quakertown, PA (G)	W-501D5	1	1117	899	80	12/96
Vancouver, WA (G)	Frame 7F	1	965	1062	82	1/97
Philadelphia, PA (G)	W-501 D5A	1	1107	931	90	1Q/97
Sacramento, CA (G)	Siemens V84.2	1	635	782	90	1Q/97
Franklin, VA (G)	W-251B12	1	700	431	91	1Q/97
West Point, VA (G)	GE PG6551	1	659	361	85	1Q/97

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COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
WESTERN REGIONAL OFFICE

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Governor
ARGEO PAUL CELLUCCI
Lt. Governor

TRUDY COXE
Secretary
DAVID B. STRUHS
Commissioner

August 12 1996

FILE COPY

Mr. B. F. Wetmore, President
Lane Construction Corporation
965 East Main Street
Meriden, Connecticut

Re: BAPCD - Westfield
Regulation 310 CMR 7.02(2)(a)
Diesel Generator at Lane Construction Corporation-Westfield

Transmittal # 53807
Application # 1-P-95-084

FINAL APPROVAL

Dear Mr. Wetmore:

The Department of Environmental Protection ("DEP"), Bureau of Waste Prevention, Western Regional Office ("Department") received on September 13, 1995 a Non Major Comprehensive Plan Application from Lane Construction Corporation, 965 East Main Street, Meriden, Connecticut ("Lane Construction") for the installation and operation of a Caterpillar 3508B diesel generator at 311 Mountain Road, Westfield, Massachusetts. The plan bears the seal and signature of James E. Gagnon, Massachusetts Registered Professional Engineer No. 29550.

Review of the application by Department personnel reveals that Lane Construction proposes to operate the Caterpillar 3508B DITA (diesel ignition, turbocharged and aftercooled) generator set to generate power for the operation of an existing asphalt plant.

Engine Description
The Caterpillar 3508B DITA diesel generator set has an electrical power rating of 910 KW prime power, 480 volt, three phase, 60 hertz at 1800 rpm. The engine specifications are listed below.

Engine Specifications

Engine type:	V-8, 4 stroke-cycle turbo charged water cooled diesel ignition.
Engine Power Rating w/fan:	1329 Bhp @ 1800 rpm
Maximum Fuel Consumption:	66.0 gal./hour
Exhaust Silencer:	Critical grade silencer
Stack Height:	19 feet above ground

Lane Construction has proposed to restrict fuel oil consumption to 200,000 gallons/year and has shown that with proposed NOx emission control and the worst case emission rates the potential emissions will not exceed major source classification thresholds.

Best Available Control Technology ("BACT")
As a non-major source for all pollutants Lane Construction must demonstrate that they will control emissions from the engines to a level that meets BACT as required by Regulation 310 CMR 7.02(2)(a).

Lane has performed a BACT analysis looking at three different options and a Caterpillar Model 3508B generator with no pollution controls at prime power operating for 2259 hours/year as the base emissions case.

Waukesha model VPH 5900 CSI natural gas fired engine with a three way non-selective catalytic reduction ("NSCR") catalyst.

Caterpillar 3508B engine with a selective catalytic reduction ("SCR") NOx control system, and

Jenbacher model JGS 320 natural gas fired engine.

A summary of the emissions performance guarantees are presented in the table below:

Table I. Electric Generation System options and the Maximum Emission Limits

Pollutant	Caterpillar 3508B Diesel Engine (base case)	Waukesha VPH 5900 GSI Natural Gas Engine	Caterpillar 3508B Diesel Engine with SCR	Jenbacher JGS 320 Natural Gas Engine
NOx	5.28 g/Bhp-hr 17.5 tons/year	0.44 g/hp-hr 1.8 tons/year	0.55 g/Bhp-hr 2.4 tons/year	0.54 g/Bhp-hr 1.7 tons/year
CO	0.05 g/Bhp-hr 0.2 tons/year	0.4 g/Bhp-hr 1.5 tons/year	0.05 g/Bhp-hr 0.2 tons/year	0.64 g/Bhp-hr 2.0 tons/year
VOC	0.19 g/Bhp-hr 0.6 tons/year	0.08 g/Bhp-hr 0.3 tons/year	0.19 g/Bhp-hr 0.6 tons/year	0.32 g/Bhp-hr 1.0 tons/year

Lane has concluded that operation of the Caterpillar Model 3508B generator with a Zeolite based SCR catalyst and urea injection represents BACT for all pollutants generated by the engine. The CER-NOx control system will include the following equipment:

CER-NOx Reactor - Includes flanges sample ports, ports for temperature and differential pressure measurement. Sufficient space for four catalyst layers.

Catalyst packing - All zeolite honey comb catalyst modules. Three layers.

Reducing agent (urea, 40% solution) metering injection system:

Semi-automatic reducing agent injection control system:

Reducing agent (urea, 40% solution) storage tank.

It is the opinion of the Department that operation of a Caterpillar Model 3508B generator with the above mentioned controls and fuel use limits proposed by Lane Construction and referenced in this FINAL APPROVAL represents Best Available Control Technology. The Department hereby grants FINAL APPROVAL of the installation and operation described herein and in the submittal pursuant to the Regulations and 310 CMR 7.02(2)(a) of the "Regulations for the Control of Air Pollution in the Berkshire Air Pollution Control District", subject to the following provisions:

1. OPERATING REQUIREMENTS - Lane Construction shall limit the fuel use in the generator to no more than 150,000 gallons of red dye distillate per year, based on a 12 month rolling total. An hour meter shall be installed on the engine and a record on the hours of operation kept on a monthly basis. Fuel consumption shall be tracked by installing a fuel flow meter the engine and keeping a monthly record of the fuel consumed. Fuel records shall be kept on site for a minimum of five years and made available to the Department upon request.

2. **Lane Construction shall limit the sulfur content of the fuel oil burned in the generator to no more than 0.05% by weight.**

3. Lane Construction shall limit emissions from the generator to levels no higher than the limits specified below:

Engine/Generator Emission Limits

	PM	NOx	CO	VOC
grams/Bhp-hour	-	0.55	0.05	0.19
lb/hour	1.2	1.6	0.15	0.56

4. Lane Construction shall take steps immediately to abate any nuisance condition should one arise due to the operation of this equipment. Possible nuisance conditions from the engines include conditions of air pollution created from visible emissions (310 CMR 7.06), noise (310 CMR 7.09), or odor (310 CMR 7.10).

5 TESTING REQUIREMENTS - Lane Construction shall perform NOx, CO, and VOC emission stack testing to demonstrate compliance with the emission limits specified in the approval during representative maximum and typical operating conditions. A summary of the requirements is provided below:

a. Lane Construction shall complete the required stack testing within 180 days after initial startup of the generator.

b. Lane Construction shall submit a pretest protocol for the required emission tests for review and written approval at least 45 days prior to the anticipated date of testing. Include in the pretest protocol a description of sampling point locations, sampling equipment, sampling analytical procedures, and the operating conditions for the required testing.

c. Lane Construction shall conduct compliance stack testing in accordance with procedures set forth in Appendix A of 40 CFR Part 60 or another method approved by the Department.

d. Lane Construction shall submit the emission test report for the review and written Department approval within 45 days of the completion of the compliance stack testing. Include a record of generator and pollution control system operating parameters with the submittal.

6. REPORTING REQUIREMENTS - Lane Construction shall notify the Department in writing of the completion of installation for the engine/generator set and the date of initial start-up within 30 days after initial startup.

7. RECORDKEEPING REQUIREMENTS - Lane Construction shall generate monthly reports in-house that document fuel use and compliance with provision 1 of this Approval. <u>If the fuel use limit is exceeded, Lane Construction shall notify the Department in writing no later than the 15th day of the following month.</u>

8. Lane Construction shall record the engine/generator set and pollution control equipment maintenance activities in a log book and shall have it available for Department personnel upon request.

9. Lane Construction shall record pressure drop across the catalyst bed and flue gas temperature entering the catalyst bed during full operation (not startup or shutdown phases) on a daily basis. Each record shall be kept

on file for a minimum of five years and made available to Department representatives upon request.

This approval pertains only to the air quality control aspect of the proposed engines and does not negate the responsibility of the owners or operators to comply with other applicable State, Local, or Federal laws and regulations

The Department has determined that the filing of an Environmental Notification Form ("ENF") with the Secretary of Environmental Affairs, for air quality control purposes, was not required prior to this action by the Department. Notwithstanding this determination, the Massachusetts Environmental Policy Act and Regulation 301 CMR 11.00, section 11.03, provide certain "Fail-Safe Provisions" which allow the Secretary to require the filing of an ENF and/or an Environmental Impact Report at a later time.

This FINAL APPROVAL is an action of the Department. There are limited rights of appeal. For a description of these rights, read the enclosure "APPEAL RIGHTS".

If you have any questions regarding this FINAL APPROVAL, please do not hesitate to contact Richard Creswell of the Western Regional Office.

Very truly yours,

Mark Schleeweis
Permit Section Chief
Bureau of Waste Prevention
Western Region

RNC/rnc
Inwfiden.apr

cc: Walter Sullivan, DEP, One Winter Street, Boston, MA 01208
Westfield Board of Health

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5 February 2001

Mr. Michael J. Wagner, Vice President
Block Island Power Company
100 Ocean Avenue
New Shorham, RI 02807

Dear Mr. Wagner:

The Department of Environmental Management, Office of Air Resources has reviewed and approved your application for the installation of fuel burning equipment and air pollution control equipment located at 100 Ocean Avenue, Block Island.

Enclosed is a minor source permit issued pursuant to our review of your application (Approval No. 1586 and 1587).

Should you have any questions I can be reached at 222-2808, extension 7011.

Very truly yours,

COPY

Douglas L. McVay
Associate Supervising Engineer
Office of Air Resources

cc: Stacey L. McFadden, P.E., LFR
Building Official - New Shoreham
Brendan McCahill - USEPA

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR RESOURCES

MINOR SOURCE PERMIT

BLOCK ISLAND POWER COMPANY

APPROVAL NO. 1586 & 1587

Pursuant to the provisions of Air Pollution Control Regulation No. 9, this minor source permit is issued to:

Block Island Power Company

For the following:

Installation of Engine No. 23, a Caterpillar 1648 HP Model No. 3516B diesel generator equipped with a selective catalytic reduction (SCR) system to reduce NO_x emissions from the engine prior to discharge into the atmosphere. The engine shall burn diesel fuel containing 0.05 percent sulfur, by weight, or less.

Located at: *100 Ocean Avenue, New Shorham*

This permit shall be effective from the date the engine and SCR system installation is completed and shall remain in effect until revoked by or surrendered to the Department. This permit does not relieve *Block Island Power Company* **from compliance with applicable state and federal air pollution control rules and regulations. The design, construction and operation of this equipment shall be subject to the attached permit conditions and emission limitations.**

COPY	***COPY***
Stephen Majkut, Chief **Office of Air Resources**	**Date of Issuance**

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR RESOURCES

Permit Conditions and Emission Limitations

BLOCK ISLAND POWER COMPANY

APPROVAL NO. 1586 & 1587

A. Emission Limitations – Engine No. 23

1. Nitrogen Oxides (as Nitrogen Dioxide (NO_2))

   a. The concentration of nitrogen oxides discharged to the atmosphere from Engine No. 23 shall not exceed 70 ppmv, on a dry basis, corrected to 15% O_2 (1-hour average)

   b. The emission rate of nitrogen oxides discharged to the atmosphere from Engine No. 23 shall not exceed 2.38 lbs. per hour.

   c. Emissions of nitrogen oxides generated from Engine No. 23 shall be treated by an SCR system and reduced by 90% before discharge to the atmosphere.

2. Carbon Monoxide (CO)

   The emission rate of carbon monoxide from the engine exhaust shall not exceed 3.42 gr/bhp-hr or a maximum of 12.43 lbs. per hour, whichever is more stringent.

3. Total Nonmethane Hydrocarbons (NMHC)

   The emission rate of total nonmethane hydrocarbons from the engine exhaust shall not exceed 0.24 gr/bhp-hr or a maximum of 0.5 lbs. per hour, whichever is more stringent.

4. Sulfur Dioxide (SO_2)

   a. All diesel fuel burned in the engine shall contain no more than 0.05 percent sulfur by weight.

   b. The emission rate of sulfur dioxide discharged to the atmosphere from the engine exhaust shall not exceed 0.58 lbs. per hour.

5. Particulate Matter (PM)

The emission rate of particulate matter discharged from the engine exhaust shall not exceed 0.13 gr/bhp-hr or a maximum of 0.48 lbs. per hour whichever is more stringent.

6. Ammonia (NH_3)

a. The concentration of ammonia discharged to the atmosphere shall not exceed 30 ppmv, on a dry basis, corrected to 15 percent O_2 (1-hour average).

b. The emission rate of ammonia discharged to the atmosphere shall not exceed 0.44 lbs. per hour.

c. The ammonia limitations in Conditions A.6.a and A.6.b shall be reviewed by the Department after the first complete catalyst life cycle of the Engine 22 SCR system. The owner/operator shall submit to the Office of Air Resources a report summarizing ammonia monitoring data for the first complete catalyst life cycle of the Engine 22 SCR system. This report shall be submitted at least 60 days prior to the end of the first complete catalyst life cycle. After completion of this review, the Department may establish a new lower ammonia slip limitation for the facility. Any new ammonia slip limitation shall be based on historical data obtained from this facility and shall provide for operational flexibility and an appropriate margin of compliance. Calculation of any new ammonia slip limitation shall be based on statistical methods, numerical methods or other appropriate analytical methodology that is deemed acceptable by the Department.

Nothing in this condition shall preclude the Department from establishing a lower ammonia slip limitation if it determines that unreacted ammonia, either alone or in combination with other emissions, may be injurious to human, plant or animal life, cause damage to property or unreasonably interfere with the enjoyment of life and property.

B. Operating Requirements

1. Visible emissions from any engine at the facility shall not exceed 10% opacity except for a period or periods aggregating no more than three minutes in any one hour. This visible emission limitation shall not apply

during startup of an engine. Engine startup shall be defined as the first five minutes of firing following the initiation of firing.

2. All diesel fuel burned at this facility shall contain no more than 0.05 percent sulfur by weight.

3. The quantity of nitrogen oxides emitted from the entire facility shall not exceed 130,000 lbs in any consecutive 12-month period up to and including the 12-month period beginning February 2001 and ending January 2002. Effective with the 12-month period beginning March 2001 and ending February 2002 and for all 12-month periods thereafter, the quantity of nitrogen oxides emitted from the entire facility shall not exceed 70,000 lbs in any consecutive 12-month period.

4. Engine 21, Engine 22 or Engine 23 shall be operated at all times, except for engine malfunctions/repairs.

5. The SCR system shall be operated at all times that Engine 23 is operating except for:

   a. engine startup; Engine startup shall be defined as the first five minutes of firing following the initiation of firing;

   b. engine shutdown; Engine shutdown shall be defined as the cessation of operation for any purpose;

   c. periods of low loads where the engine exhaust temperature is less than 600°F. At all times, the owner/operator shall operate its facility so as to minimize the period of time that engine exhaust temperature is less than 600°F so as to maximize use of the SCR system.

6. Urea shall be injected into the SCR system whenever the catalyst bed is at or above 600°F.

C. Continuous Monitors

1. Engine 23 shall be equipped with a non-resettable elapsed time meter to indicate, in cumulative hours, the elapsed operating time.

2. The generator shall be equipped with a kilowatt-hour meter to indicate, in cumulative kilowatt-hours, the power generated by each engine-generator set.

3. The owner/operator shall install and operate a thermocouple to measure inlet temperature to the SCR system.

4. The owner/operator shall install and operate a flowmeter on the urea supply line to monitor overall urea consumption.

5. The owner/operator shall install and operate a manometer to monitor pressure drop across the SCR catalyst.

D. Compliance Determinations

1. Compliance with the emission limitations in Conditions A.1-6 shall be based on one-hour average concentrations. Initial performance testing shall consist of three-one hour test runs at a load typical of representative operation (75-80%) and one-one hour test run at a high load condition (90-100%) and a low load condition (50-60%). Compliance with the emission limitations must be demonstrated for each of the test runs.

2. Compliance with the limitation for nitrogen oxides emissions in Condition B.3 shall be determined by using the procedures in Attachment A and the following emission factors:

a.	Engine No. 21:	0.00144 lbs. of NO_x emitted per horsepower-hour.
b.	Engine No. 22:	0.0016 lbs of NO_x emitted per horsepower-hour.
c.	Engine No. 23:	0.00144 lbs. of NO_x emitted per horsepower-hour.
d.	All other engines:	AP-42 emission factors for NO_x from diesel engines

The compliance determination shall include periods of low loads where the engine exhaust temperature is less than 600°F and the SCR system is not used. Emission factors during these periods shall be 0.0144 lbs./hp-hr for Engines 21 and 23 and 0.016 lbs./hp-hr for Engine 22.

3. Compliance with the diesel fuel sulfur limits may be determined based on a certification from the fuel supplier. Fuel supplier certifications shall include the following information:

a. The name of the fuel supplier;

b. The sulfur content of the fuel from which the shipment came or the shipment itself;

c. The location of the fuel when the sample was drawn for analysis to determine the sulfur content of the fuel, specifically including whether the fuel was sampled as delivered to Block Island Company or whether the sample was drawn from fuel in storage at the fuel supplier's facility or another location;

d. The method used to determine the sulfur content of the fuel.

4. As an alternative to fuel supplier certification, the owner/operator may elect to sample the fuel prior to combustion. Sampling and analysis shall be conducted for the fuel in the initial tank(s) of fuel to be fired in the engines and after each new shipment of fuel is received. Samples shall be collected from the fuel tank immediately after the fuel tank is filled and before any fuel is combusted.

E. Stack Testing

1. Within 180 days of completing the engine and SCR system installation, initial performance testing shall be conducted on the engine. Performance testing shall be conducted for nitrogen oxides, carbon monoxide, particulate matter, ammonia and total nonmethane hydrocarbons.

   Thereafter, emission testing shall be conducted annually to determine compliance with the nitrogen oxides emission limitations. Annual emissions testing for nitrogen oxides shall consist of three-one hour test runs at a load typical of representative operation (75-80%).

2. A stack testing protocol shall be submitted to the Office of Resources for review and approval prior to the performance of any stack tests. A copy of the stack testing protocol for the initial performance testing shall be sent to EPA for review and approval. The owner/operator shall provide the Office of Air Resources at least 60 days prior notice of any performance test.

3. All test procedures used for stack testing shall be approved by the Office of Air Resources prior to the performance of any stack tests.

4. The owner/operator shall install any and all test ports or platforms necessary to conduct the required stack testing, provide safe access to any platforms and provide the necessary utilities for sampling and testing equipment.

5. All testing shall be conducted under operating conditions deemed acceptable and representative for the purpose of assessing compliance with the applicable emission limitation.

6. A final report of the results of stack testing shall be submitted to the Office of Air Resources no later than 60 days following completion of the testing.

7. All stack testing must be observed by the Office of Air Resources or its authorized representatives to be considered acceptable.

F. Record Keeping and Reporting

1. The owner/operator shall, on a monthly basis, no later than 10 days after the first of each month, determine the nitrogen oxides emissions for the entire facility for the previous 12 months. The owner/operator shall keep records of this determination and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

2. The owner/operator shall notify the Office of Air Resources in writing within 15 days, whenever the quantity of nitrogen oxides emitted from the Block Island facility exceeds that allowed by Condition B3.

3. The owner/operator shall, on a monthly basis, no later than 10 days after the first of each month, determine and record the hours of operation for each engine for the previous month. The owner/operator shall keep records of this determination and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

4. The owner/operator shall, on a monthly basis, no later than 10 days after the first of each month, determine and record the kilowatt-hours generated for each engine-generator set for the previous month. The owner/operator shall keep records of this determination and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

5. The owner/operator shall, on a monthly basis, no later than 10 days after the first of each month, determine and record the fuel usage for Engine 23 and the urea consumption for the previous month. The owner/operator shall calculate and record a urea-to-fuel ratio using this data. The owner/operator shall keep records of these determinations and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

6. The owner/operator shall maintain copies of all fuel supplier certifications or fuel analyses and these copies shall be made accessible for review by the Office of Air Resources or its authorized representative and EPA. These records shall include a certified statement, signed by the

owner/operator of the facility, that the records represent all of the fuel combusted at the facility.

7. The owner/operator shall notify the Office of Air Resources, in writing, of the date of actual start-up of the SCR system and Engine No. 23, no later than fifteen days after such date.

8. Inlet temperature to the SCR system and engine load shall be continuously monitored and recorded in an operating log on an hourly basis. The owner/operator shall keep records of these determinations and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

9. Pressure drop across the SCR catalyst shall be recorded on a monthly basis. The owner/operator shall keep records of this determination and provide such records to the Office of Air Resources or its authorized representative and EPA upon request.

10. The owner/operator shall maintain properly signed, contemporaneous operating logs, or other relevant evidence to document actions during startup shutdown periods.

11. The owner/operator shall notify the Office of Air Resources in writing of any planned physical or operational change to any equipment that would:

    a. Change the representation of the facility in the application.

    b. Alter the applicability of any state or federal air pollution rules or regulations.

    c. Result in the violation of any terms or conditions of this permit.

    d. Qualify as a modification under APC Regulation No. 9.

    Such notification shall include:

    - Information describing the nature of the change.

    - Information describing the effect of the change on the emission of any air contaminant.

    - The scheduled completion date of the planned change.

    Any such change shall be consistent with the appropriate regulation and have the prior approval of the Director.

12. The owner/operator shall notify the Office of Air Resources of any noncompliance with the terms of this permit, in writing, within 5 days of the occurrence.

13. All records required in this permit shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Office of Air Resources or its authorized representative and EPA upon request.

G. Malfunctions

1. Malfunction means a sudden and unavoidable breakdown of process or control equipment. In the case of a malfunction of any air pollution control system, all reasonable measures shall be taken to assure resumption of the designed control efficiency as soon as possible. In the event that the malfunction of an air pollution control system is expected or may reasonably be expected to continue for longer than 24 hours and if the owner/operator wishes to operate the source on which it is installed at any time beyond that period, the Director shall be petitioned for a variance under Section 23-23-15 of the General Laws of Rhode Island, as amended. Such petition shall include, but is not limited to, the following:

   a. Identification of the specific air pollution control system and source on which it is installed;

   b. The expected period of time that the air pollution control system will be malfunctioning or out of service;

   c. The nature and quantity of air contaminants likely to be emitted during said period;

   d. Measures that will be taken to minimize the length of said period;

   e. The reasons that it would be impossible or impractical to cease the source operation during said period.

2. The owner/operator may seek to establish that a malfunction of any air pollution control system that would result in noncompliance with any of the terms of this permit or any other applicable air pollution control rules and regulations was due to unavoidable increases in emissions attributable to the malfunction. To do so, the owner/operator must demonstrate to the Office of Air Resources that:

   a. The malfunction was not attributable to improperly designed equipment, lack of preventative maintenance, careless or improper operation or operator error;

b. The malfunction is not part of a recurring pattern indicative of inadequate design, operation or maintenance;

c. Repairs were performed in an expeditious fashion. Off-shift labor and overtime should be utilized, to the extent practicable, to ensure that such repairs were completed as expeditiously as practicable.

d. All possible steps were taken to minimize emissions during the period of time that repairs were performed.

e. Emissions during the period of time that the repairs were performed will not:

   (1) Cause and increase in the ground level ambient concentration at or beyond the property line in excess of that allowed by Air Pollution Control Regulation No. 22 and any Calculated Acceptable Ambient Levels; and

   (2) Cause or contribute to air pollution in violation of any applicable state or national ambient air quality standard.

f. The reasons that it would be impossible or impractical to cease the source operation during said period.

g. The owner/operator's actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence.

This demonstration must be provided to the Office of Air Resources within two working days of the time when the malfunction occurred and contain a description of the malfunction, any steps taken to minimize emissions and corrective actions taken.

The owner/operator shall have the burden of proof in seeking to establish that noncompliance was due to unavoidable increases in emissions attributable to the malfunction.

H. Other Permit Conditions

1. To the extent consistent with the requirements of this approval and applicable Federal and State laws, the facility shall be designed, constructed and operated in accordance with the representation of the equipment in the permit application prepared by LFR Levine Fricke dated 16 August 2000.

2. Employees of the Office of Air Resources or its authorized representatives and EPA shall be allowed to enter the facility at all times for the purpose of inspecting any air pollution source, investigating any condition it believes may be causing air pollution or examining any records required to be maintained by the Office of Air Resources.

3. The emission limitations of Condition A.1-6 shall not apply during engine startup/shutdown conditions and periods when the engine exhaust temperature is less than 600°F. Engine startup shall be defined as the first five minutes of firing following the initiation of firing. Engine shutdown shall be defined as the cessation of operation for any purpose

4. The Office of Air Resources shall reopen and revise this permit:

   a. If it determines that a material mistake was made in establishing the operating restrictions; or,

   b. If it determines that inaccurate emission factors were used in establishing the permit.

5. The owner/operator may appeal any final determination by the Office of Air Resources to reopen and revise an emission limitation or permit condition to the Administrative Adjudication Division for Environmental Matters (AAD). Appeals must be filed within 30 days of the Office of Air Resources final determination.

6. At all times, including periods of startup, shutdown and malfunction, the owner/operator shall, to the extent practicable, maintain and operate the facility in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Office of Air Resources, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures and inspection of the source.

I. Excess Emissions Due to an Emergency

As the term is used in this condition an "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of his source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes this source to exceed any emission limitation or condition under this permit, due to unavoidable increases in emission attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

The owner/operator may seek to establish that noncompliance with an emission limitation or condition under this permit was due to an emergency. To do so, the owner/operator shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An emergency occurred and that the owner/operator can identify the cause(s) of the emergency;

2. The permitted facility was at the time being properly operated;

3. During the period of the emergency the owner/operator took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

4. The owner/operator submitted notice of the emergency to the Office of Air Resources within 2 working days of the time when emission limitations or permit conditions were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions and corrective actions taken.

The owner/operator shall have the burden of proof in seeking to establish the occurrence of an emergency.

J. Monitoring of Ammonia Emissions

1. The owner/operator shall monitor ammonia emissions from the SCR system for Engine 23. Ammonia emissions shall be measured using Conditional Test Method 27 (CTM-027) or another method approved by the USEPA and the Director. Ammonia emissions shall be monitored according to the following schedule:

   a. Ammonia emissions shall be measured during the initial performance testing required by Condition E.1.

   b. Thereafter ammonia emissions shall be measured after 13,000 hours of SCR system operation after startup and once every 750 operating hours until the SCR catalyst is replaced.

   c. This testing schedule may be revised by the Office of Air Resources if it determines, based on the ammonia emissions testing for the Engine 22 SCR system, that the above schedule is not sufficient to monitor compliance with Condition A.6 of this permit.

Attachment A
Compliance Determination
Block Island Power
Condition B.3

ENGINE NUMBER	ENGINE HP RATING	ENGINE KW RATING	ENGINE HOURS (PREVIOUS 12 MONTHS) (1)	MAXIMUM POWER OUTPUT (KW-HRS) (2)	ACTUAL POWER OUTPUT (KW-HRS) (PREVIOUS 12 MONTHS) (3)	LOAD FACTOR (4)	NO_x EMISSION FACTOR (LB/HP-HR) (5)	NO_x EMISSIONS MAXIMUM LOAD (LBS/HR) (6)	NO_x EMISSIONS (TONS) (PREVIOUS 12 MONTHS) (7)
11	2000	1136					0.024	48.0	
19	1615	1100					0.024	38.76	
21	2336	1640					0.00144	3.37	
22	1961	1360					0.0016	3.10	
23	1648	1150					0.00144	2.38	
Total									

Notes:
1. Information determined pursuant to Condition F.3 of this permit
2. Maximum Power Output = Engine Hours x Engine kW rating
3. Information determined pursuant to Condition F.4 of this permit
4. Load Factor = Actual Power Output/Maximum Power Output
5. Emission factors for Engine Nos. 11 and 19 are based on data in Chapter 3.4 "Large Stationary Diesel and All Stationary Dual-Fuel Engines"
   Emission factor for Engine No. 21 is based on manufacturer's data in Appendix D of the permit application for Engine 21 and the SCR system.
   Emission factor for Engine No. 22 is based on data in the permit application for Engine 22 and the SCR system.
   Emission factor for Engine No. 23 is based on manufacturer's data in Appendix E of the permit application for Engine 23 and the SCR system.
6. NO_x Emissions Maximum Load = AP-42 NO_x Emissions Factor x Engine HP Rating
7. NO_x Emissions = NO_x Emissions Maximum Load x Load Factor x Hours Operated

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PERMIT TO OPERATE

GREAT BASIN UNIFIED AIR POLLUTION CONTROL DISTRICT
157 Short Street ★ Bishop, California 93514 ★ (760) 872-8211 ★ Fax (760) 872-6109

PERMIT Nº 897

Formally Temporary Permit to Operate Nº 776, with ATC modification 884

Pursuant to the authority granted under Rule 209-B of the Rules and Regulations for the Great Basin Unified Air Pollution Control District, the

Mountain Utilities
Post Office Box 1
Kirkwood, CA 95646

is hereby granted a **Permit to Operate** as of <u>November 7, 1997</u>, for the following described operations, associated equipment and buildings located at:

Mountain Utilities
1547 Kirkwood Meadows Drive
Kirkwood, CA 95646

This Permit to Operate is granted for one year and shall be renewed upon payment of the renewal fee on or before the stated anniversary date.

OPERATION, EQUIPMENT, FOR PERMIT: Electricity generation plant, consisting of:
6 - Caterpillar diesel generator sets. Also known as; "The Equipment."

1) Model Nº 399	S/N 36Z01198	rated @ 800 kW	1,195 hp
2) Model Nº 398	S/N 66B3619	rated @ 500 kW	853 hp
3) Model Nº 398	S/N 66B3618	rated @ 500 kW	853 hp
4) Model Nº 399	S/N 25B2624	rated @ 800 kW	1,195 hp
5) Model Nº 399	S/N 25B3423	rated @ 800 kW	1,195 hp
6) Model Nº 399	S/N 25B3413	rated @ 800 kW	1,195 hp
Including the following equipment	TOTAL	4.2 mWe	6486 hp

1 - Maxon model ECB-3-SP diesel fired burner rated @ 2.8 mmbtu/hr
2 - 15,000 gallon below ground diesel fuel storage tanks*
1 - 10,000 gallon below ground diesel fuel storage tanks*
1 - 1000 gallon day tank*
1 - 6000 gallon sludge tank*

CONTROL SYSTEM: Consisting of an exhaust manifold with 45 foot exhaust stack:
1 - Selective Catalytic Reduction (SCR) unit.
1 - 12,000 gallon capacity aqueous ammonia chemical storage tank**(permit fee exempt)

PERMIT CONDITIONS: This permit is granted subject to the attached conditional approval 1 through [redacted]. Pages 1 to 5.

... Permit does not authorize the above permittee to iolate any of the Rules and Regulations of the Great Basin ified Air Pollution Control District or Division 26, ... ter 2, Article 3, of the Health & Safety Code of the t... of California. Any modification of the equipment or peration, as defined in District Rule 200.A, will require new permit. This permit shall be posted as prescribed in istrict Rule 200.D.

Ellen Hardebeck
AIR POLLUTION CONTROL OFFICER

Date December 7, 1998

Note: For Permit renewal purposes, the anniversary date is the date the permit was first issued.

CONDITIONAL APPROVAL for PERMIT TO OPERATE № 897

Mountain Utilities
Post Office Box 1
1547 Kirkwood Meadows Drive
Kirkwood, CA 95646

1) Right-of-entry

The "Right of Entry", as defined by California H&S Code § 41510 of Division 26, shall apply at all times with respect to the equipment and the Control System. Representatives of the Great Basin Unified Air Pollution Control District upon presentation of credentials, shall be permitted to enter the Mountain Utilities' Generator Building to inspect and copy any record required to be kept under the terms of this permit. District staff shall also be permitted to inspect any equipment, work practices, air-emission-related activity or method dictated by this permit. If deemed necessary by the District to verify compliance with these conditions, Mountain Utilities shall within 7 days notice be available to open any sample extraction port, or exhaust outlet for the purpose of conducting source tests or to collect samples. In enforcing the terms of this permit, any cost incurred in collecting samples, source testing and laboratory analysis fees shall be the responsibility of the applicant. [Origin of Condition: District Rule 302 *Analysis Fee*]. [Origin of Condition: District Rule 210].

2) Severability clause

If any provision of this permit is found invalid, such finding shall not affect any remaining provisions. [Origin of Condition: District Rule 107].

3) Breakdown (or Emergency) Reporting & Operating Under Breakdown Conditions

Mountain Utilities shall comply with the breakdown requirements of District Rules 403 (Breakdown), which shall include notifying the Air Pollution Control Officer of a breakdown condition within an hour of detection, unless it can be demonstrated that a longer reporting period is necessary -- not to exceed two (2) days. Notification shall identify the time, location, equipment involved, and to the extent possible the cause of the breakdown and steps taken to correct the breakdown condition. Within one (1) week after the breakdown occurrence Mountain Utilities shall submit a written report to the Air Pollution Control Officer which includes: date of correction of the breakdown, determination of the cause of the breakdown, corrective measures to prevent a recurrence, an estimate of the emissions caused by the breakdown condition, and pictures of the failed equipment, if available. Breakdown conditions shall not persist longer than 24-hours or the end of the production run, whichever is sooner, except for continuous monitoring equipment, for which the period shall be ninety-six (96) hours, unless Mountain Utilities obtains an Emergency Variance pursuant to District Rule 617 (Emergency Variance). [Origin of Condition: District Rules 403].

4) Right to revise permit.

The provisions of this permit may be modified by the District if it determines the stipulated controls are inadequate. The controls shall be considered inadequate if the nitrogen dioxide monitor shows a violation of the California 1 hour air quality standard of 470 $\mu g/m^3$, or the Federal Annual Average Standard of 100 $\mu g/m^3$ from the equipment emissions alone. [Origin of Condition: District Rules 210.C].

5) Toxic condition
Mountain Utilities shall notify the District within 2 days in writing should they learn of, or encounter, conditions where toxic air emissions are allowed to disperse into the ambient air. Toxic air emissions are those listed on the AB2588 list of substances as required by the California Health & Safety Code Section 44321. [Origin of Condition: District Rule 402].

6) Record keeping
Required record keeping information shall be retained by Mountain Utilities in a form suitable for inspection for a period of at least two (2) years from the end of the calendar year of the journal entry. [Origin of Condition: District Rule 206.B, & [redacted]].

7) Meteorological Monitoring Station.
As described in Mountain Utilities's *Ambient Air Quality Monitoring Plan, Feb 18, 1997*, an ambient air quality monitoring network shall be located near the Mountain Utilities generator building. Instrumentation shall include wind speed, direction, and temperature. All data shall be stored on an electronic acquisition & retrieval system permitting District surveillance by means of a telephone modem connection. The District shall consider all data retrieved by this means as preliminary. The hourly data in final quality assured form shall be presented to the District on digital disc on a quarterly schedule. Instrumentation, operating procedures, quality assurance along with the data handling procedures shall be subject to APCO approval. Meteorological monitoring equipment shall be kept in good operating condition through a program of maintenance and calibration practices according to the manufacturer's recommendations and the procedures outlined in the EPA document *Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD), Publication Nº EPA-450/4-87-007.* Calibration and maintenance records shall be logged at Mountain Utilities' generator building and made available to GBUAPCD staff upon request. This condition shall terminate one year after the District grants a Permit to Operate. [Origin of Condition: District Rules 206.A, & 210.A].

8) Equipment start-up notification
The Selective Catalytic Reduction (SCR) unit shall be installed according to the design specification submitted by Mountain Utilities on February 15, 1997 with the revised Authority to Construct application. Mountain Utilities shall formally notify the District in writing when construction is complete and the equipment is ready for inspection. Written start-up notification shall be delivered to the District office by Postal Service delivery or facsimile transmission at least 48 hours prior to equipment start-up. Operation of this equipment without a written Permit to Operate is a violation of District Rule 200 B, and can result in civil and criminal penalties (Cal H&S Code § 42400). [Origin of Condition: District Rule 200-B].

9) The SCR NO_x control system shall be installed on the electric generator plant exhaust stack and operated to achieve compliance with the terms and conditions of this permit. This SCR system shall be permanently installed with each Caterpillar® generator exhaust manifolded into one common exhaust stack. Operation of the electric generator plant shall be limited to the maximum production rates, schedules of operation, and process material as specified in the Authority to Construct application. This control system shall at all times be operated and maintained in accordance with good air pollution control practices. Good air pollution control practices may be determined by the proper operating parameter ranges for the SCR unit based on

the compliance source test (condition 19) conducted over the operating range of the electric power plant. Operating parameters may include, but are not limited to: the SCR outlet NO_X concentration as measured by the continuous emissions monitoring (CEM) device, the ammonia injection to fuel-use ratio, and the gas temperature in the SCR unit. Following the installation of the SCR unit, hourly nitrogen dioxide emissions shall be limited to a maximum 13.2 pounds per hour. Mountain Utilities shall also comply with an annual emission limit of 35 tons of oxides of nitrogen from the power plants as measured on a rolling 12-month basis. Compliance with the hourly and annual limits can be determined using the source specific emissions factors of fuel usage to NO_X emissions to be derived from source testing or by performance testing as specified in condition 19. [Origin of Condition: District Rule 216, NSR].

10) A continuous emission monitoring (CEM) device shall be installed, which will be used to optimize the effectiveness of the Control Equipment. The output from the CEM will be recorded continuously to demonstrate that the Control Equipment is operating at all times the generators are running. A thermocouple will be installed in the SCR Control to continuously monitor the temperature within the Unit. A minimum gas temperature of 680 Degrees Fahrenheit shall be maintained at all times except as provided in Condition 18. The CEM chart and SCR temperature records shall be kept in a form suitable for inspection for two years and will be made available to the District staff upon request. The selected CEM shall be properly maintained according to the manufacturer's recommendations and will be serviced daily with zero and span checks performed in accordance with the Federal requirement 40 CFR 60.13d. [Origin of Condition: District Rule 206].

11) Mountain Utilities will install a fuel flow meter to determine total fuel usage among the six diesel engines and a meter on the ammonia tank to determine ammonia usage. Using the source specific emission factor derived from the source testing, Mountain Utilities will demonstrate compliance with the maximum hourly emission rate on a daily basis based on the daily fuel usage data. Mountain Utilities shall also record ammonia usage on a daily basis. These records shall be maintained at Mountain Utilities' field office and made available to District Staff upon request. These records shall be kept for a period of two years. The electric plant operator(s) shall inform the District staff of any CEM monitor breakdown by the procedures outlined in condition 3 [Origin of Condition: District Rules 403 & 206].

12) An industrial grade of aqueous ammonia shall be injected ahead of the catalyst bed with the NH_3 delivery proportioned over the entire power plant load range [redacted] ~~Using fuel flow rates as an indicator, NH_3 gas shall be calculated and injected upstream of the selective catalytic reactor unit at a rate of not less than (to be determined by source testing methods conducted within 180 days of start-up, and as outlined under permit condition 19) [insert #] gallons NH_3 per 100 gallons of fuel consumed.~~ [Origin of Condition: District Rule 206]. [redacted].

13) Mountain Utilities shall use only low sulfur diesel fuel, with a sulfur content of 0.05% or less by weight. The amount of sulfur dioxide exhausted to the atmosphere shall not exceed 0.2% by volume. [Origin of Condition: District Rules 416 and 210].

14) Exhaust stack visible emissions shall not exceed a Ringelmann 1 (20% opacity) for a period or periods aggregating more than three minutes in any one hour. [Origin of Condition: District Rule 400].

15) Ammonia escaping from (slip rate) the catalytic converter shall not exceed 50 ppm_v corrected to 15% oxygen [Origin of Condition: District Rule 402].

16) The applicant shall keep a sufficient supply of aqueous ammonia NH_3 on hand to allow for immediate system replenishment. If another reagent other than aqueous ammonia is chosen for use as the reaction medium, the APCO shall review the request and give written approval prior to its use. [Origin of Condition: District Rule 210.A].

17) The SCR system shall be operated at all times except under breakdown conditions (condition 3) and during regularly scheduled maintenance activities as recommended by the SCR manufacturer. When the SCR unit is not operating Mountain Utilities plant operator(s) shall not emit untreated exhaust gas from more than one diesel engine at any time. If the maintenance activity continues for more than one day, a breakdown event shall be reported by the procedures outlined in condition 3. Operation of the SCR unit is not required when the Mountain Utilities' Power Plant is not operating. [Origin of Condition: District Rule 403].

18) Mountain Utilities shall provide safe and accessible sampling ports similar in design to those specified in 40 CFR 60, Appendix A, Test Method 1 which allows for performance sampling of the SCR system. Within 180 days of start-up, and annually for the first two years after installation of the SCR controls, Mountain Utilities shall test the exhaust emissions emitted from the power generator exhaust stack. If testing shows compliance during the first two years, Mountain Utilities will thereafter perform source testing once every three years. A test plan must be submitted to the Air Pollution Control District not later than 60 days before the proposed test date. This testing protocol shall be approved by the District before testing begins. In order to be considered a valid source test, testing shall be performed while the diesel engines are operated over their expected operating range up to 80 percent of the engines maximum rated capacity. To determine good air pollution control practices (condition 9), the plan must include a summary of the proposed operating conditions during the test, the identity of the testing laboratory, a statement from the testing laboratory certifying it meets the testing criteria called for by the California Air Resources Board and a description of all sampling and analytical procedures to be used. Testing shall at a minimum include at least 3 traverses using the following test methods (Rule 200.C, and Cal H&S Code Sec 44340). A copy of the test results shall be submitted to the District within 15 days of acquisition by Mountain Utilities .

EPA Method 1	Velocity traverses for Stationary Sources.
EPA Method 2	Determination of Stack Gas Velocity and Volumetric Flow Rates (Type S Pilot Tube). Application of EPA F factors [40 CFR 60.45] may be substituted for EPA Method 2.
EPA Method 3	Gas analysis (Orsat)
EPA Method 7E	Determination of Nitrogen Oxide Emissions from Stationary Sources.
EPA Method 10	Determination of Carbon Monoxide Emissions from Stationary Sources.
EPA Method 350.3	Ammonia Analysis by selective ion electrode.

19) **AB2588 "Hot Spot" Source Testing**

By August 1, 1998, and every four years thereafter, the applicant shall have performed by a reputable source testing firm the chemical analysis for the appropriate elements, compounds, and substances listed as toxic which may be emitted to the atmosphere. Alternatively, Mountain Utilities may submit data from other sources, acceptable to the District, in lieu of source testing. The applicant shall perform toxic source testing in accordance with law, for any toxin in use at the time and for which there was no previous source test. Toxic air emissions are those listed on the AB2588 list of substances as required by the California Health & Safety Code Section 44321. Before performance testing begins, Mountain Utilities and their contractor shall submit a source test protocol. The source test protocol shall describe the procedures and methods to be used during source testing. These testing methods shall be approved by the District in advance of their use. (In order to comply with the source testing requirements of AB 2588 ("The Toxic Hot Spot Act"), the District requests the following test methods:)

EPA Method 6010	Inductively Coupled Plasma Atomic Emission Spectroscopy for trace elements: Arsenic (As), Beryllium (Be), Cadmium (Cd), Total Chromium, Copper (Cu), Lead (Pb), Manganese (Mn), Nickel (Ni), and Zinc (Zn)
EPA Method 7196	For Chromium (hexavalent, Cr-VI)
EPA Method 7471	For Mercury (Hg)
EPA Method 7740	For Selenium (Se)
CARB Method 429	Source testing procedure for determining polycyclic aromatic hydrocarbons (PAH) emissions.
CARB Method 430	Source testing procedure for determining formaldehyde emissions from stationary sources.
ASTM Method D808-87	Standard Test Method for Chlorine in New and Used Petroleum Products (Bomb Method).
ASTM Method D129-64	Standard Test Method for Sulfur in Petroleum Products (general Bomb Method).

[redacted]

22

AUTHORITY TO CONSTRUCT / OPERATING PERMIT
WITH CONDITIONS
Number A-00707 Modification #1
(addition of a powerscreen)

PERMITTEE:	Kiewit Companies
ADDRESS:	1515 E. Tropicana Ave, Suite 680 Las Vegas, NV 89129
SOURCE DESCRIPTION:	Temporary Diesel Generators and Powered Screen for construction of:
SOURCE LOCATION:	Eldorado Energy 701 Eldorado Valley Drive Boulder City, NV 89005
SOURCE SIC:	1629 - Specialized Heavy Construction

Signature: Michael H. Naylor
Director
Air Pollution Control Division

3/22/99

Date of Issuance

Signature:
Chris Koenig
Responsible Official for:
Kiewit Companies

Date

Signature: Elizabeth A. Gilmartin
NSR Supervisor
Air Pollution Control Division

Date

Signature: Paul Durr
APC Permit Specialist II
Air Pollution Control Division

Date

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I EMISSION UNITS

A. LIST OF EMISSIONS UNITS

Table I-A-1: Summary of Emissions Units and Fees

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
A001	ONAN M/N:125DGEA Diesel Genset S/N:44238850 ~200HP, 10 GPH @ full load	D2	$40.70	20200102
A002	Caterpillar M/N:3406 Diesel Genset ~537 HP, 26 GPH @ full load. Fitted with Miratech Catalyst	D1	$163.00	20200102
A003	Caterpillar M/N:3406 Diesel Genset ~537 HP, 26 GPH @ full load. Fitted with Miratech Catalyst	D1	$163.00	20200102
A004	Caterpillar M/N:3406 Diesel Genset ~537 HP, 26 GPH @ full load. Fitted with Miratech Catalyst	D1	$163.00	20200102
B1	Excavation/trenching	P1	$163.00	30502513
B2	Screening, tripple deck Chieftan Powerscreen	P1	$163.00	30502511
B3	Stacking (total of 3 points)	P1	$163.00	30502505
B4	Stockpiles and disturbed surfaces, 1 acre	S1	$163.00	30502507
C1	Diesel engine on powerscreen, 2 GPH	D2	$40.70	20200102
		Total	$1222.40	

The shaded emission units are being added in Mod 1 which began operation in July of 1998. Fees for the modification will be prorated for 1998. Equipment fees shown are for 1999 and will be adjusted annually by the CPI.

II EMISSIONS LIMITATIONS

Actual Emissions from the entire facility shall not exceed the Allowable Emissions of Table II-B-1 and 2.

Table II-B-1 Facility Allowable Emissions (tons per year) based on actual hours

1998 Combined Emissions

PM-10	**1.78**
CO	**2.80**
VOC	**0.27**
NOx	**8.82**
SOx	**2.35**

Table II-B-2 Facility Allowable Emissions (tons per year) based on actual hours

1999 (and subsequent years) Combined Engine Emissions

PM-10	**2.04**
CO	**4.21**
VOC	**0.25**
NOx	**10.62**
SOx	**4.91**

Note: SOx emission data provided by the manufacturer was based on 0.2% sulfur fuel in the power generation engines. Actual emissions using 0.05% sulfur fuel will be less.

III PRODUCTION LIMITATIONS

The calculated Potential to Emit Regulated Air Pollutants shall not exceed the following limits:

(a) Calculated Potential to Emit for the ONAN Genset.

Pollutant	lbs/hr	tons in 1998	tons in 1999+
PM-10	0.1	0.11	0
CO	0.88	0.96	0
VOC	0.13	0.14	0
NOx	4.05	4.42	0
SOx	0.24	0.26	0

b) Calculated Potential to Emit for each Caterpillar Genset (for unit running 24 hrs/day, 7 days/week).

Pollutant Per Engine	lbs/hour (each)	tons in 1998 (22 weeks)	tons in 1999+ (52 weeks)
PM-10	0.09	0.17	0.39
CO	0.59	1.09	2.58
VOC	0.03	0.06	0.13
NOx	1.46	2.70	6.38
SOx	0.70	1.30	3.06

c) Calculated Potential to Emit for the powerscreen.

Pollutant Per Engine	lbs/hour	lbs/day	tons/year
PM-10	4.9	79.4	1.38
CO	0	0	0
VOC	0	0	0
NOx	0	0	0
SOx	0	0	0

d) Calculated Potential to Emit for the diesel engine on the powerscreen.

Pollutant Per Engine	lbs/hour	lbs/day	tons/year
PM-10	0.07	1.07	0.03
CO	0.20	3.26	0.10
VOC	0.08	1.20	0.04
NOx	0.94	15.01	0.45
SOx	0.06	1.00	0.03

1. Operation of the Onan genset shall be limited to 13 weeks in 1998.

2. Operation of the 3 Caterpillar gensets shall be limited to 22 weeks in 1998 and 52 weeks in 1999+.

3. The gensets shall be limited to the following operating schedule:

1998 Engine Operating Data			
	Hours/day	Days/Week	Weeks/Year
Genset #1	24	7	13
Genset #2	24	7	22
Genset #3	10	5	22
Genset #4	10	5	22

1999 + Engine Operating Data			
	Hours/day	Days/Week	Weeks/Year
Genset #1	0	0	0
Genset #2	24	7	52
Genset #3	10	5	52
Genset #4	10	5	52

4. The gensets and catalytic converters must be maintained in good working order pursuant to the manufacturers maintenance schedule, or more frequently if conditions dictate. The Caterpillar gensets will not be operated without the catalytic converters installed and functioning properly.

5. Only low sulfur Diesel fuel (<0.05% sulfur) may be used in the gensets.

6. Only low sulfur Diesel fuel (<0.05% sulfur) may be used in the gensets.

7. The powerscreen is limited to **16** hours/day and **960** hours/year.

8. The powerscreen is limited to **135** tons/hour, **2160** tons/day and **60000** tons/year.

9. The source must maintain at least **1.5%** moisture in the material being excavated and screened.

10. The source must not allow the powerscreen to emit fugitive dust emissions which exhibits greater than **10%** opacity for a period or periods aggregating more than 3 minutes in any 60 minute period.

IV CONDITIONS

A Administrative

1. Pursuant to Subsections 12 and 16 (as revised), the CONTROL OFFICER issues this Authority to Construct / Operating Permit, with conditions.
2. Pursuant to Subsection 12 (as revised), any physical change, or any change in operation, which causes, or has the potential to cause, a Net Emissions Increase shall obtain an Authority to Construct prior to such change.
3. Pursuant to Subsection 25.2.1 (as revised), any Upset/Breakdown or Malfunction shall be reported to the Control Officer within one (1) hour of the onset of such event.
4. Pursuant to Subsection 4.3 (as revised), the Control Officer or his representative may enter into the property, with or without prior notice.
5. This Authority to Construct / Operating Permit, or a copy, shall be kept on-site.
6. This Authority to Construct / Operating Permit does not replace, supersede, or circumvent permitting requirements of any other regulatory agency.
7. If any condition is found to be invalid, then such invalidity shall not affect any other conditions which can be given effect without the invalid condition(s).
8. Pursuant to Sections 12 and 16 (as revised), failure to comply with any of these conditions is a violation of Section 12 or 16.
9. No emissions unit, other than those listed in Table I, shall be installed, modified, or operated without an approved Authority to Construct issued by APCD.

B MITIGATION.

This source must mitigate their emissions. Emissions from the actual operating schedule for 1998 has been used to calculate the offset obligation for 1998. 1999 data is presented for estimation use only.

ESTIMATED 1998 OFFSET OBLIGATION

Based on 1 Onan and 3 Caterpillar generator sets running 100% load for the source-specified number of hours and a powerscreen.

Pollutant	Type	Total	Offset Ratio	Total Due
PM-10	Section 12 or 58	1.78	2	3.56
CO	Section 12 or 58	2.80	2	5.60
VOC	Section 12, 52 or 58	0.27	2	0.54
NOx	Section 12 or 58	8.82	2	17.64
SOx	None due	2.35	0	0
			Total	27.34

ESTIMATED 1999 AND SUBSEQUENT YEARS OFFSET OBLIGATION

Based on 3 Caterpillar generator sets with Miratech catalytic converters running 100% load for the source-specified number of hours and a powerscreen.

Pollutant	Type	Total	Offset Ratio	Total Due
PM-10	Section 12 or 58	2.04	2	4.08
CO	Section 12 or 58	4.21	2	8.42
VOC	Section 12, 52 or 58	0.25	2	0.50
NOx	Section 12 or 58	10.62	2	21.24
SOx	None due	4.91	0	0
			Total	34.24

Applicant is required to pre-purchase **4.0** tons of ERC offsets as a result of this modification to satisfy its obligation. (34.24 original permit - 30.24 this permit = 4.0) Any over-payment will be reconciled during 1998 Emission Inventory survey and the obligation will be based on actual emission in subsequent years.

Permittee must obtain or purchase ERCs within 30 days of receiving the permit.

Failure to comply with this requirement may be considered a violation of Section 12 of the APCD regulation and could result in enforcement action before the Air Pollution Control Hearing Officer.

C POST CONSTRUCTION MONITORING

Post construction monitoring is not required.

D COMPLIANCE DEMONSTRATION

No compliance demonstration is required.

E RECORD KEEPING

1. All records, logs, etc. shall be made available to APCD during regular business hours.

2. All records, logs, etc., or a copy thereof, shall be kept on site for a minimum of three (3) years from the date the measurement, or data was entered.

3. Various records, logs, etc., shall contain, at minimum, the following information:
   a) Hours of operation of the diesel gensets.
   b) Amount of diesel fuel used,
   c) Tons of material excavated and processed through the powerscreen,
   d) Amount of diesel fuel used by the diesel engine on the powerscreen.

F REPORTS and REPORTING

1. Each report shall:

a) as the first page, have a signed statement of completeness and accuracy;
b) be based on the calendar quarter;
c) be submitted on or before January 30 each year; and
d) be addressed to the attention of the Compliance Supervisor, APCD.

2. Each annual report shall contain, at minimum, the following:
   a) as the first page, have a signed statement of completeness and accuracy;
   b) summarized information contained in E3.

G OTHER REQUIREMENTS

There are no other requirements.

V DEFINITIONS

District means District Board of Health of Clark County

Regulations means the District Board of Health of Clark County, Air Pollution Control Regulations

APCD means the Air Pollution Control Division of the Clark County Health District

Date of Issuance means the date the Director, APCD signed the "Authority to Construct/Operating Permit Certificate"

Actual Initial Start-up Date means:

For a ***new stationary source***, the date on which any emission unit of the stationary source is set into operation for any reason.

For a ***modified stationary source***, the date on which any new or modified emission unit of the stationary source is set into operation at any production rate greater than the previously permitted production rate but no later than the Expiration Date of the "Authority to Construct Certificate".

Anticipated Initial Start-up Date means that date declared by the applicant pursuant to Subsection 12.14.1 (Rev 09-96).

Allowable Emissions shall have the meaning as defined in 40 CFR 51.165(a)(1)(xi)

Actual Emissions shall have the meaning as defined in 40 CFR 51.165(a)(1)(xii)(A)

Total PM_{10} means filterable and condensable particulate matter with an aerodynamic diameter less than or equal to 10 microns.

Genset means a diesel powered generator.

VI EMISSIONS CALCULATIONS

See the Technical Support Document for Registration File #A00707.

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#OP-99-013
DEC#NS77-0001
Operating Permit Expiration Date: September 5, 2005

State of Vermont
Agency of Natural Resources
Department of Environmental Conservation

Air Pollution Control Division
Waterbury, Vermont

AIR POLLUTION CONTROL PERMIT TO OPERATE

Date Permit Issued: September 5, 2000

Owner/Operator:	Okemo Mountain, Inc. 77 Okemo Ridge Road Ludlow, Vermont 05149
Source:	25 Stationary Diesel Engines Okemo Mountain, Inc. 77 Okemo Ridge Road Ludlow, Vermont 05149

FINDINGS OF FACT

(A) FACILITY DESCRIPTION

Okemo Mountain, Inc. (hereinafter "Okemo" and also referred to herein as "Owner/Operator") owns and operates a recreational facility (also referred to herein as "Facility") located in Ludlow, Vermont. The Facility is listed under the Standard Industrial Classification ("SIC") Code #7011, Ski Lodges and Resorts, and #7999, Amusement and Recreation Services, Not Elsewhere Classified. The resort currently consists of a mixed-use development that combines residential and vacation housing with the ski resort operations and various commercial activities. Air contaminant sources at the Facility include fourteen (14) diesel engines owned by Okemo, eleven (11) leased diesel engines, and several insignificant activities.

Okemo is modifying the Facility to meet the Reasonably Available Control Technology (hereinafter "RACT") for nitrogen oxides (hereinafter "NO_X") required by §5-251 of the *Vermont Air Pollution Control Regulations* (hereinafter "*Regulations*"). The RACT determination includes the installation of a selective catalytic reduction (hereinafter "SCR") control device on one of the existing engines and an engine replacement schedule that is more accelerated than the requirements outlined in §5-271 of the *Regulations*. The RACT determination is outlined in Section I of this document.

(B) FACILITY CLASSIFICATION

The Facility is classified as a source of air contaminants pursuant to §5-401(6), Fuel Burning Installations, of the *Regulations*. In addition, §5-101 of the *Regulations* defines a stationary source as any structure(s), equipment, installation(s), or operation(s), or combination thereof, which emit or may emit any air contaminant, which is located on one or more contiguous or adjacent properties and which is owned or operated under common control. Based on this definition, all of the equipment, operations, and structures at the Facility are grouped together by the Agency of Natural Resources, Department of Environmental Conservation, Air Pollution Control Division (hereinafter "Agency") as one stationary air contaminant source for purposes of review under the *Regulations*.

(C) PRIOR APPROVALS

The Agency originally granted an indirect source permit for an expansion to the parking facilities pursuant to the requirements of §556 of Title 10 *Vermont Statutes Annotated*, (hereinafter "*V.S.A.*") and §5-501 of the *Regulations* on May 5, 1989. Since this date the Agency has issued 2 amendments to the original approval. These are summarized in the table below. This Facility does not currently operate under an existing Air Pollution Control Permit to Construct for any of the onsite stationary sources.

Prior Agency Approvals	
Date Approval Issued	Description of Approval/Amendment
May 5, 1989	Original Agency indirect source permit approval to expand the parking facilities.
January 31, 1995	Amendment issued to extend the construction deadline.
May 26, 1998	Amendment approving further expansion of the parking facilities.

Since the application for the Permit to Operate is the initial application under Subchapter X of the *Regulations*, this Facility does not currently operate under an existing Air Pollution Control Permit to Operate.

(D) PERMIT APPLICABILITY

As noted above, Okemo is classified as a source of air contaminants under Section 5-401 of the *Regulations*. Pursuant to Title 10 *Vermont Statutes Annotated*, (hereinafter "*V.S.A.*") §556a and §§5-1002, 5-1003, and 5-1005 of the *Regulations*, Okemo is currently classified as a "Title V Subject Source" and is subject to the requirement to obtain an Air Pollution Control Permit to Operate. Okemo is therefore subject to Subchapter X of the *Regulations*, as well as the federal operating permit requirements of Title 40 Part 70 or 71 of the *Code of Federal Regulations* ("*CFR*").

(E) APPLICATION PROCESSING AND PUBLIC PARTICIPATION

On June 16, 1999 the Agency received an application from Okemo for an Air Pollution Control Permit to Operate the Facility. The Agency reviewed the application and determined that it was administratively complete on June 24, 1999.

Pursuant to *10 V.S.A.* § 556a and § 5-1007 of the *Regulations*, the Agency published notice in the *Valley News* on July 1, 1999 that it had received an administratively complete application from Okemo to operate the Facility. On May 9, 2000 the Agency found that it had received complete plans, specifications and analyses regarding the source.

Public notice was published in the *Valley News* on August 3, 2000 of the Agency's plans to issue an Air Pollution Control Permit for the Facility. The notice will solicited public comments on the application, the Agency's technical review, and the proposed decision for thirty (30) days. The notice also provided an opportunity to request an informational meeting on the matter, if requested in writing at least five (5) days before the close of the comment period. The comment period closed on September 1, 2000. The affected state(s) of New Hampshire, New York, Massachusetts along with the U.S. Environmental Protection Agency were notified of the Agency's draft decision on August 2, 2000.

Pursuant to *10 V.S.A.* §§556 and 556a, the Agency is required to fully consider all written and oral public comments submitted concerning the draft permit prior to taking final action on the draft permit. No public comments were submitted regarding the draft permit.

(F) NEW SOURCE REVIEW DESIGNATION

The Facility is designated as a major stationary source of air contaminants, as defined in §5-101 of the *Regulations*. Okemo is not proposing to modify the Facility except to meet the Agency's RACT determination for NO_x and therefore is not subject to review under 10 *V.S.A.* §556.

(G) ALLOWABLE EMISSIONS

Based on the information provided by the applicant, the Agency finds the Facility's current allowable emissions to be:

Facility Allowable Emissions (tpy)						
Air Contaminant	PM/PM_{10}	SO_2	NO_x	CO	VOC	HAPs
Facility Allowable Emissions	12	36	211	57	16	<1

Based on the information provided by the applicant, the Agency finds the Facility's allowable emissions, **after achieving all NO_x RACT requirements by November 2005**, to be:

Facility Allowable Emissions (tpy)						
Air Contaminant	PM/PM_{10}	SO_2	NO_x	CO	VOC	HAPs
Facility Allowable Emissions	4	26	80	39	8	<1

(H) APPLICABLE REQUIREMENTS

The Facility is subject to the following state and federal laws and regulations, the requirements of which are contained in the conditions of this Permit:

(a) State Requirements (*Vermont Air Pollution Control Regulations*):

Applicable Requirements from *Vermont Air Pollution Control Regulations*
§5-201- Prohibition of Open burning
§5-211(2) - Prohibition of Visible Air Contaminants, Installations Constructed Subsequent to April 30, 1970
§5-221(1) - Prohibition of Potentially Polluting Materials in Fuel, Sulfur Limitation in Fuel
§5-221(2) - Prohibition of Potentially Polluting Materials in Fuel, Waste Oil
§5-231(3) - Prohibition of Particulate Matter; Combustion Contaminants
§5-231(4) - Prohibition of Particulate Matter; Fugitive Particulate Matter
§5-241 - Prohibition of Nuisance and Odor
§5-251(3) - Control of Nitrogen Oxide Emissions; Reasonably Available Control Technology for Large Stationary Sources
§5-271 - Control of Air Contaminants from Stationary Reciprocating Internal Combustion Engines
§5-403 - Circumvention
Subchapter VIII - Registration of Air Contaminant Sources
Subchapter X - Operating Permits

(b) Federal Requirements:

Applicable Requirement from Federal Regulations
40 CFR Part 60, Subpart Kb, Section 60.116b(a) and (b) - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels), Monitoring of Operations

(c) Non-Applicable Requirements

Pursuant to §5-1015(a)(11) of the *Regulations*, Okemo may request a *permit shield* from specific state or federally enforceable regulations and standards which are not applicable to the source. The applicant has not requested a permit shield in accordance with the requirements of §5-1015(a)(11) of the *Regulations*.

(l) CONTROL OF NITROGEN OXIDES EMISSIONS - RACT for §5-251(3) of the *Regulations*

Pursuant to §5-251(3) of the *Regulations* if any stationary source has allowable emissions of one hundred (100) tons per year or more of nitrogen oxides, the Facility shall install, maintain, and use reasonably available control technology ("RACT") to limit the discharge of nitrogen oxides from the source. RACT is defined as devices, systems, process modifications, or other apparatus or techniques designed to prevent or control emissions that are reasonably available, taking into account the social, environmental and economic impact of such controls, and alternative means of emission control.

Okemo has estimated allowable emissions of two hundred eleven (211) tpy of nitrogen oxides from the twenty-five (25) diesel engine generators. Okemo is therefore subject to NO_x RACT. Okemo's initial RACT proposal was submitted on June 16, 1999 with the Facility's application to operate. A revised proposal was submitted on March 17, 2000 and has been approved by the Agency as Okemo's RACT determination. The determination included a combination of emissions reductions means spread out over the next five (5) years. The proposal has been set up on a time line as described below.

November 1, 2000: Okemo will install and operate a selective catalytic reduction ("SCR") control device on the Caterpillar 3516 diesel engine generator. Okemo will also replace four of the Caterpillar 3408B engines with four Detroit Diesel engines or equivalently sized engines that have "not to exceed" emission rates of 6.9 grams per brake horsepower-hour ("g/bhp-hr") for NOx, 1.0 g/bhp-hr for VOC, 8.5 g/bhp-hr fro CO and 0.40 g/bhp-hr for PM or lower. All engines are to be limited to 1500 hours of operation each per year, except for the Caterpillar 3408B's, Caterpillar 3406B's, and Cummins VTA1710P engines that are to have an hours of operation cap of 1450 hours per year ("hrs/yr"). A temporary Caterpillar 3516B will be installed for the purpose of electricity generation. This engine will have "not to exceed" emissions of 6.5 g/bhp-hr for NO_X, 0.3 g/bhp-hr for VOC, 0.6 g/bhp-hr fro CO and 0.2 g/bhp-hr for PM or lower and be limited to 600 hrs/yr. A reduction of forty (40) tons per year ("tpy") of NO_X will be achieved.

November 1, 2001: No changes are required.

November 1, 2002: Okemo will retire two (2) of the Cummins VTA1710P engines and four (4) of the Detroit Diesel engines. Okemo will install and operate two (2) Caterpillar 3512B DITA engines that meet the July 1, 2007 emissions standards outlined in §5-271(c) of the *Regulations*. The new Caterpillar engines will have an hours of operation cap of 1500 hrs/yr. A reduction of twenty-nine (29) tpy of NO_X will be achieved.

November 1, 2003: Okemo will retire two (2) of the Cummins VTA1710P engines and install and operate an additional Caterpillar 3512B DITA engines that meet the July 1, 2007 emissions standards outlined in §5-271(c) of the *Regulations*. The new Caterpillar engine will have an hours of operation cap of 1500 hrs/yr. A reduction of fourteen (14) tpy of NO_X will be achieved.

November 1, 2004: Okemo will retire five (5) of the Caterpillar 3408B and Caterpillar 3406B engines. Okemo will install and operate two (2) Caterpillar 3512B DITA engines or equivalently sized engines that meet the July 1, 2007 emissions standards outlined in §5-271(c) of the *Regulations*. The new Caterpillar engines will have an hours of operation cap of 1500 hrs/yr. A reduction of thirty-seven (37) tpy of NO_X will be achieved.

November 1, 2005: Okemo will retire three (3) of the Detroit Diesel Engines. A reduction of twelve (12) tpy of NO_X will be achieved.

(J) HAZARDOUS MOST STRINGENT EMISSION RATE

Pursuant to §5-261 of the *Regulations*, if the regulated emissions of a hazardous air contaminant from the entire Facility are in excess of the Action Level for the hazardous air contaminant, the Facility shall be subject this section and the hazardous air contaminant shall be subject to the Hazardous Most Stringent Emission Rate ("HMSER"). Hazardous air contaminant emissions from virgin fuel combustion are not subject to §5-261 of the Regulations. The Facility is not expected to have regulated emissions of any hazardous air contaminant in excess of an Action Level. Therefore, the facility is not subject to HMSER under §5-261 of the *Regulations*.

(K) STATE AND FEDERAL ENFORCEABILITY

This section will delineate which permit conditions are federally enforceable and which permit conditions are state only enforceable. For federal enforceable conditions a general statement will also be made that these conditions, and these conditions only, are subject to federal citizen suit provisions. In cases where a state and federal standard has been streamlined, this section will specify only the underlying federal requirement as being federally enforceable.

All conditions of this Permit are enforceable by both state and federal authorities.

(L) REASONABLY AVAILABLE CONTROL TECHNOLOGY - RACT for §5-1010 in the *Regulations*

In accordance with 10 *V.S.A.* §556a(d), as amended, and §5-1010 of the *Regulations* the Agency may establish and include within any operating permit issued under this section emission control requirements based on Reasonably Available Control Technology ("RACT"). The Agency has not determined RACT for this Facility at this time.

(M) COMPLIANCE CERTIFICATION

Okemo will certify compliance as part of its annual registration with the Agency pursuant to the requirements of Subchapter VIII of the *Regulations*.

Based on the Agency's review of Okemo's application and the above Findings of Fact, the Agency concludes that the operation of the Facility, subject to the following Permit conditions, complies with all applicable state and federal air pollution control laws and regulations or is subject to an acceptable schedule of compliance. Therefore, pursuant to *10 V.S.A.* §556 and §556a, as amended, the Agency hereby issues a Permit approving the operation of the Facility, as described in the above Findings of Fact, subject to the following:

PERMIT CONDITIONS

- CONSTRUCTION AND EQUIPMENT SPECIFICATIONS -

(1) Okemo shall construct and operate the Facility in accordance with the plans and specifications submitted to the Agency on June 16, 1999, the Agency's RACT determination, and in accordance with the conditions set forth herein. [10 *V.S.A.* §556a(d)]

(2) Okemo shall control emissions from the existing Caterpillar 3516 diesel engine by installing and operating a combined SCR control device and oxidation catalyst by November 1, 2000 that shall achieve a 90% or better reduction rate of nitrogen oxides. All elements of this air pollution control system shall be maintained in good working order at all times and operated in accordance with the manufacturer's operation and maintenance recommendations. The air pollution control system shall be in operation whenever the emission source is in operation. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

(3) Okemo shall cease operation and remove from the Facility eighteen (18) of the existing engines as specified within the time line below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Equipment	Latest Date of Removal
Two (2) Caterpillar 3408B's Diesel Engines	November 1, 2000
Two (2) Cummins VTA1710P Diesel Engines	November 1, 2002
Four (4) Leased Detroit Diesel Engines	November 1, 2002
Two (2) Additional Cummins VTA1710P Diesel Engines	November 1, 2003
Two (2) Additional Caterpillar 3408B Diesel Engines	November 1, 2004
Three (3) Caterpillar 3406B Diesel Engines	November 1, 2004
Three (3) Additional Leased Detroit Diesel Engines	November 1, 2005

(4) Okemo may install and operate nine (9) new diesel engines if done in accordance with the Facility's RACT determination and as specified in the time line below. All elements of the diesel engines shall be maintained in good working order at all times and operated in accordance with the manufacturer's operation and maintenance recommendations. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Equipment	Latest Date of Installation
Four (4) Leased Detroit Diesel Engines	November 1, 2000
One (1) Temporary Caterpillar 3516B Diesel Engine	November 1, 2000
Two (2) Caterpillar 3512B Diesel Engines	November 1, 2002
One (1) Caterpillar 3512B Diesel Engine	November 1, 2003
One (1) Caterpillar 3512B Diesel Engine	November 1, 2004

(5) Okemo must cease operation of the Caterpillar 3516B diesel engine two years from the initial start-up date. This period may be extended for this engine or a replacement engine if approved in writing by the Agency. Okemo shall notify the Agency in writing and shall provide the following information for the proposed piece of equipment. [10 *V.S.A.* §556a(d)] [§5-251(3)(c) of the *Regulations*]

(a) Make, model, serial number, and date of manufacture;

(b) Engine size (brake horsepower), maximum fuel firing rate and stack parameters; and

(3) "Not to exceed" emissions data.

(6) Okemo shall vent the exhaust of all diesel engines at the Facility through stacks having outlets at least four (4) feet above any roofline or structure which may significantly interfere with the exhaust gases. The stacks shall not be equipped with any devices that would obstruct the upward discharge of exhaust gases. [10 *V.S.A.* §556a(d)]

(4) Okemo shall install a non-resettable elapsed time meter on each diesel engine. [10 *V.S.A.* §556a(d)]

- OPERATING LIMITS -

(5) Okemo shall ensure that all stationary reciprocating internal combustion engines of 450 bhp or greater installed at the Facility prior to July 1, 1999 comply with the emission standards of §5-271 of the Regulations by July 1, 2007. All stationary reciprocating internal combustion engines of 450 bhp or greater installed after July 1, 1999 shall comply with the applicable emissions standards of §5-271 of the Regulations immediately upon installation. Installation of any size stationary reciprocating internal combustion engine may require approval from the Agency in the form of an amended Permit prior to installation. [10 *V.S.A.* §556a(d)] [§5-271 of the *Regulations*]

(6) The hours of operation of all of the Cummins VT1710P, the Caterpillar 3406B and the Caterpillar 3408B engines shall not exceed 1450 hours per year per engine based on any rolling twelve consecutive calendar month period. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

(7) The hours of operation of all of the Detroit Diesel 12V92TADDECL, the SCR equipped Caterpillar 3516, and the Caterpillar D3512B engines shall not exceed 1500 hours per year per engine based on any rolling twelve consecutive calendar month period. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

(8) The hours of operation of the temporary Caterpillar 3516B engine shall not exceed 600 hours per year based on any rolling twelve consecutive calendar month period. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

(9) Any emergency diesel engine shall be used only during emergency power failures except for a maximum of 100 hours per year each for routine testing and maintenance. The emergency engines shall not be used as part of any utility peaking or load shedding activities. [10 *V.S.A.* §556a(d)] [§5-1002(h)(1)(vi) of the *Regulations*]

(10) Only fuel oil with a maximum sulfur content not to exceed 0.5 percent by weight may be used as fuel in any of the diesel engines unless Okemo obtains prior written approval from the Agency to use another type of fuel. [10 *V.S.A.* §556a(d)] [§5-221(1)(a) of the *Regulations*]

- EMISSION LIMITATIONS -

(11) Emissions from each of the leased Detroit Diesel engines shall not exceed the emission limits specified in the table below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*] [§5-271 of the *Regulations*]

Pollutant	grams/brake horsepower hour	lbs/hour
NO_x	6.9	6.7
CO	3.0	2.9
PM10	0.4	0.4

Any emission testing conducted to demonstrate compliance with the above emission limits shall be performed in accordance with Title 40 *Code of Federal Regulations* Part 60, Appendix A, Reference Method 7E for NO_x, Reference Method 10 for CO, and Reference Method 5 for PM_{10} or equivalent methods approved in writing by the Agency. [§5-404 of the *Regulations*]

(12) Emissions from the SCR equipped Caterpillar 3516 engine shall not exceed the emission limits specified in the table below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Pollutant	grams/brake horsepower hour	lbs/hour
NO_x	1.6	5.2
CO	0.6	1.8
PM10	0.04	0.1

Any emission testing conducted to demonstrate compliance with the above emission limits shall be performed in accordance with Title 40 *Code of Federal Regulations* Part 60, Appendix A, Reference Method 7E for NO_x, Reference Method 10 for CO, and Reference Method 5 for PM_{10} or equivalent methods approved in writing by the Agency. [§5-404 of the *Regulations*]

(13) Emissions from each of the Caterpillar 3512B diesel engines shall not exceed the emission limits specified in the table below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Pollutant	grams/brake horsepower hour	lbs/hour
NO_x	4.8	14.4
CO	2.6	7.8
PM10	0.2	0.4

Any emission testing conducted to demonstrate compliance with the above emission limits shall be performed in accordance with Title 40 *Code of Federal Regulations* Part 60, Appendix A, Reference Method 7E for NO_x, Reference Method 10 for CO, and Reference Method 5 for PM_{10} or equivalent methods approved in writing by the Agency. [§5-404 of the *Regulations*]

(14) Emissions from the temporary Caterpillar 3516B diesel engine shall not exceed the emission limits specified in the table below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Pollutant	grams/brake horsepower hour	lbs/hour
NO_x	6.5	30.9
CO	0.6	3.0
PM10	0.2	0.8

Any emission testing conducted to demonstrate compliance with the above emission limits shall be performed in accordance with Title 40 *Code of Federal Regulations* Part 60, Appendix A, Reference Method 7E for NO_X, Reference Method 10 for CO, and Reference Method 5 for PM_{10} or equivalent methods approved in writing by the Agency. [§5-404 of the *Regulations*]

(15) Emissions of particulate matter ("PM") from each of the Cummins VTA1710P, Caterpillar 3406B, and 3408B diesel engines shall not exceed the limits specified in the table below. [10 *V.S.A.* §556a(d)] [§5-251(3) of the *Regulations*]

Diesel Engine	lbs/MMBTU	lbs/hour
720 hp (5.3 MMBTU/hr input) Cummins VTA1710P	0.5	2.7
420 hp (3.5 MMBTU/hr input) Caterpillar 3408B	0.5	1.8
425 hp (3.5 MMBTU/hr input) Caterpillar 3406B	0.5	1.8

Any emission testing conducted to demonstrate compliance with the above emission limit shall be performed in accordance with Title 40 *Code of Federal Regulations* Part 60, Appendix A, Reference Method 5 or an equivalent method approved in writing by the Agency. [§5-404 of the *Regulations*]

(16) Visible Emissions: Emissions of visible air contaminants from any installation at the Facility shall not exceed twenty (20) percent opacity for more than a period or periods aggregating six (6) minutes in any hour and at no time shall visible emissions exceed sixty (60) percent opacity. [§5-211 of the *Regulations*]

Any emission testing conducted to demonstrate compliance with the above emission limits shall be performed in accordance with the proposed Federal Reference Method F-1 contained in the Federal Register Vol.51, No.168, pp. 31076-31081, August 29, 1986 or an equivalent method approved in writing by the Agency. [§5-404 of the *Regulations*]

(17) Fugitive Emissions: Okemo shall take reasonable precautions at all times to control and minimize emissions of fugitive particulate matter from construction operations at the Facility. This shall include but not be limited to the use of wet suppression, calcium chloride applications or other dust control measures as necessary to minimize fugitive dust from all roads, traffic, and construction areas at the Facility. [§5-231(4) of the *Regulations*]

(18) Nuisance and Odor: Okemo shall not discharge, cause, suffer, allow, or permit from any source whatsoever such quantities of air contaminants or other material which will cause injury, detriment, nuisance or annoyance to any considerable number of people or to the public or which endangers the comfort, repose, health or safety of any such persons or the public or which causes or has the tendency to cause injury or damage to business or property. Okemo shall not discharge, cause,

suffer, allow or permit any emissions of objectionable odors beyond the property line of the facility. [§5-241 of the *Regulations*]

- MONITORING AND COMPLIANCE TESTING -

(19) To ensure compliance with all applicable regulations, Okemo shall perform annual tune-ups and maintenance on all diesel engines according to manufacturer's recommendations. Okemo shall record in a log book a description of all work done and the date the work was performed.

(20) Okemo shall perform emission testing for NO_x and CO on the SCR equipped Caterpillar 3516 engine within 60 days of the installation of the SCR control system and shall furnish the Agency with a written report of the results within 180 days after the initial start-up date or by May 1, 2001. The emission testing shall be performed in order to demonstrate compliance with the emission limitations specified in condition 12 of this Permit. [§§5-402(1) and 5-404(1) of the *Regulations*]

At least thirty days prior to performing the emission testing required above, Okemo shall submit to the Agency a pretest report prepared in accordance with the Agency's "Source Emission Testing Guidelines". [5-402(1) of the *Regulations*]

- RECORDKEEPING AND REPORTING -

(21) Okemo shall maintain records of the total number of hours of operation for each diesel engine generator on-site, each month. At the beginning of each month, Okemo shall calculate the total number of operating hours for each diesel engine generator during the previous twelve consecutive month period. [§5-405(1) of the *Regulations*]

(22) Okemo shall obtain from the fuel supplier, for each shipment of fuel oil received at the Facility for use in the diesel engine generators, a certification or invoice stating the sulfur content of the fuel oil. The certification or invoice shall include the name of the fuel oil supplier, date of delivery, fuel type, quantity of fuel oil delivered, and a statement from the fuel oil supplier as to the sulfur content of the fuel oil in percent sulfur by weight. [§5-405(1) of the *Regulations*]

(23) For each volatile organic liquid storage vessel at the Facility, including the fuel oil storage tanks, that was installed after July 23, 1984 and has a design capacity equal to or greater than 40 m^3 (10,562 gallons), Okemo shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Such records shall be kept for the life of the source. Prior to Okemo storing any volatile organic liquid with a maximum true vapor pressure equal to or greater than 3.5 kPa (0.5 psia) in any of the above tanks which have a design capacity equal to or greater than 75 m^3 (19,805 gallons), Okemo shall notify the Agency and comply with any additional applicable requirements of 40 *C.F.R.* Part 60 Subpart Kb. No. 2, No. 4 and No. 6 fuel oils have a maximum true vapor pressure less than 3.5 kPa (0.5 psia). [40 *C.F.R.* Part 60 Subpart Kb]

(24) Okemo shall submit to the Agency every six months from the date of issuance of this Permit a report containing the following information: [Section 5-405(1) of the *Regulations*]

(a) a summary of maintenance performed on all of the diesel engines as required by Condition (19) of this Permit;

(b) a summary of the hours of operation records for each engine required by Condition (21) of this Permit;

(c) a statement of the sulfur content of any and all fuel delivered to Okemo during the reporting period.

(25) Okemo shall submit an annual certification of compliance, concurrent with the annual registration data (see condition (33) of this Permit) submitted to the Agency, which identifies the compliance status during the past calendar year of the Facility with respect to all terms and conditions of this Permit, including but not limited to the following: [Section 5-1015(a)(8) of the *Regulations*]

(a) Identification of each term or condition of the permit that is the basis of the certification;

(b) The compliance status of the Facility with respect to each applicable requirement;

(c) The methods used for determining the compliance status of the Facility over the reporting period; and

(d) The frequency of collection of compliance data (i.e. continuous or intermittent); and

(e) A description of any deviation that occurred and corrective actions taken.

A copy of the compliance certification shall also be sent to the U.S. Environmental Protection Agency at the following address:

Air Technical Unit (Mail Code SEA)
Office of Environmental Stewardship
U.S. Environmental Protection Agency
John F. Kennedy Federal Building
Boston, MA 02203

(26) Okemo shall notify the Agency in writing of the date(s) of initial start-up of the Caterpillar 3516 engine after SCR has been installed and any new diesel engine generators within fifteen (15) days after such date(s). For the purposes of this Permit, the date of initial start-up for any new engine shall be defined as the date on which it first begins operation. The initial start-up date for the SCR/oxidation catalyst system shall mean the date on which fuel is first combusted in the Caterpillar 3416 engine once the SCR/oxidation catalyst system has been installed. [§5-402(1) of the *Regulations*]

(27) Okemo shall notify the Agency in writing within ten (10) days of any violation, of which it is aware, of any requirements of this Permit. This notification shall include, at a minimum, the cause for the violation and corrective action or preventative maintenance taken to correct the violation. [§5-402(1) of the *Regulations*] [§5-1015(a)(12) of the *Regulations*]

(28) Okemo shall notify the Agency in writing of any proposed physical or operational change at the Facility which may increase the emission rate of any air contaminant to the ambient air. Such changes shall include, but are not limited to, the addition of a generator or an increase in the total hours of operation of an existing generator above the limits of this Permit. If the Agency determines that a permit amendment is required, a new application and the appropriate application fee shall be submitted. The permit amendment shall be obtained prior to commencing any such change. [§5-501 of the *Regulations*]

(29) Okemo shall develop and implement an operation and maintenance plan for the SCR/oxidation catalyst control system prior to initial start-up of the system. Commencing upon start up of the SCR/oxidation catalyst system, Okemo shall carry out the operation and maintenance plan. Okemo shall revise this plan at the Agency's request or on its own motion to reflect equipment or operational

changes. Said operation and maintenance plan shall be present at the facility at all times and shall be made available to representatives of the Agency upon request. The operation and maintenance plan shall include, but not be limited to, predicted equipment replacement intervals, appropriate monitoring parameters to ensure proper operation, provisions for maintaining records of routine maintenance inspections, findings of those inspections, and any corrective actions which were taken. [10 *V.S.A.* §556(c), 10 *V.S.A.* §556a(d), and §5-402(1) of the *Regulations*]

(30) Annual Registration: Okemo shall calculate the quantity of emissions of air contaminants from the Facility annually. If the Facility emits more than five (5) tons of any and all air contaminants per year, Okemo shall register the source with the Secretary of the Agency (hereinafter "Secretary"), and shall renew such registration annually. Each day of operating a source which is subject to registration without a valid, current registration shall constitute a separate violation and subject the owner/operator to civil penalties. The registration process shall follow the procedures set forth in Subchapter VIII of the Air Pollution Control Regulations, including the payment of the annual registration fee on or before May 15 of each year. Annual registration forms submitted to the Agency shall contain a compliance certification statement in accordance with Condition (25) of this Permit. [§§5-802, 5-803, 5-807, and 5-808 of the *Regulations*] [§5-1015(8) of the *Regulations*]

(31) Records of all required compliance testing shall include the following: [Sections 5-402(1) of the *Regulations*]

(a) the date, place, and time of sampling or measurements;
(b) the date analyses were performed;
(c) the company or entity that performed the analyses;
(d) the analytical techniques or methods used;
(e) the results of all such analyses; and
(f) the operating conditions existing at the time of sampling or measurement.

(32) All records, reports, and notifications that are required to be submitted to the Agency by this Permit shall be submitted to: [§5-402(1) of the *Regulations*]

Agency of Natural Resources
Air Pollution Control Division
103 South Main Street, Bldg 3 South
Waterbury, Vermont 05671-0402.

(33) All records shall be retained for a minimum period of five (5) years from the date of record and shall be made available to the Agency upon request. [§5-402(1) of the *Regulations*]

-STANDARD CONDITIONS -

(34) Approval to construct or modify under this Permit shall become invalid if construction or modification is not commenced within 18 months after issuance of this Permit, if construction or modification is discontinued for a period of 18 months or more, or if construction or modification is not substantially completed within a reasonable time. The Agency may extend any one of these periods upon a satisfactory showing that an extension is justified. The term "commence" as applied to the proposed construction or modification of a source means that the owner or operator either has: [10 *V.S.A.* §556]

(a) Begun, or caused to begin, a continuous program of actual on-site construction or modification of the source, to be completed within a reasonable time; or

(b) Entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a continuous program of actual on-site construction or modification of the source to be completed within a reasonable time.

(35) These Permit conditions may be modified, suspended, terminated, or revoked for cause and reissued upon the filing of a written request with the Secretary of the Agency (hereinafter "Secretary") or upon the Secretary's own motion. Any modification shall be granted only with the written approval of the Secretary. If the Secretary finds that modification is appropriate, only the conditions subject to modification shall be re-opened. The filing of a request for modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated non-compliance does not stay any terms or conditions of this Permit. The Secretary may provide opportunity for public comment on any proposed modification of these conditions. If public comments are solicited, the Secretary shall follow the procedures set forth in 10 *V.S.A.*, §556 and §556a, as amended.. [10 *V.S.A.* §556] [10 *V.S.A.* §556a]

(36) Cause for reopening, modification, termination and revocation of this Permit includes, but is not limited to: [§5-1008(e)(4) of the *Regulations*]

(a) Inclusion of additional applicable requirements pursuant to state or federal law;

(b) A determination that the permit contains a material mistake or that inaccurate information was used to establish emissions standards or other terms or conditions of the operating permit;

(c) A determination that the operating permit must be modified or revoked to ensure compliance with applicable requirements;

(d) A determination that the subject source has failed to comply with a permit condition;

(e) For Title V subject sources, a determination by U.S. EPA that cause exists to terminate, modify, revoke or reissue an operating permit;

(f) Those causes which are stated as grounds for refusal to issue, renew or modify an operating permit under Section 5-1008(a) of the Regulations; or

(g) If more than three (3) years remain in the permit term and the source becomes subject to a new applicable requirement.

(37) Okemo shall furnish to the Agency, within a reasonable time, any information that the Agency may request in writing to determine whether or cause exists for modifying, revoking, reissuing, or terminating the permit or to determine compliance with this Permit. Upon request, Okemo shall also furnish to the Agency copies of records required to be kept by this Permit. [40 *CFR* Part 70 §70.6(a)(6)(v)]

(38) This Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize any injury to private property or any invasion of personal rights. [10 *V.S.A.* §556] [10 *V.S.A.* §556a]

(39) By acceptance of this Permit, Okemo agrees to allow representatives of the State of Vermont access to the properties covered by the Permit, at reasonable times, to ascertain compliance with Vermont environmental and health statutes and regulations and with this Permit. Okemo also agrees to give the Agency access to review and copy any records required to be maintained by this Permit, and to sample or monitor at reasonable times to ascertain compliance with this Permit. [10 *V.S.A.* §556] [10 *V.S.A.* §556a]]

(40) All data, plans, specifications, analyses and other information submitted or caused to be submitted to the Agency as part of the application for this Permit or an amendment to this Permit shall be complete and truthful and certified by a responsible official whose designation has been approved by the Secretary. Any such submission which is false or misleading shall be sufficient grounds for denial or revocation of this Permit, and may result in a fine and/or imprisonment under the authority of Vermont statutes. [10 *V.S.A.* §556] [10 *V.S.A.* §556a] [§5-1008(f) of the *Regulations*]

(41) For the purpose of establishing whether or not a person has violated or is in violation of any condition of this Permit, nothing in this Permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [10 *V.S.A.* §556a(d)]

(42) Subsequent owners of the source shall file an administratively complete application for an Air Pollution Control Permit to Operate within twelve (12) months of any change of the source's ownership. The terms and conditions of this Permit shall remain in full force and effect until the issuance of a new Permit to Operate. [Section 5-1005(a)of the Regulations]

(43) The provisions of this Permit are severable. If any provision of this Permit, or its application to any person or circumstances is held invalid, illegal, or unenforceable by a court of competent jurisdiction, the invalidity shall not apply to any other portion of this Permit which can be given effect without the invalid provision or application thereof. [10 *V.S.A.* §556] [10 *V.S.A.* §556a]

(44) Any permit noncompliance could constitute a violation of the federal Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. [§§5-1008(a) and 5-1008(e) of the *Regulations*]

(45) It shall not be a defense for Okemo in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this Permit. [10 *V.S.A.* §556] [10 *V.S.A.* §556a]

(46) Okemo shall submit to the Agency a complete application for renewal of the Operating Permit at least twelve (12) months before the expiration of the Operating Permit. If a timely and administratively complete application for an operating permit renewal is submitted to the Secretary, but the Secretary has failed to issue or deny such renewal before the end of the term of this Operating Permit, then Okemo may continue to operate the subject source and all terms and conditions of this Operating Permit shall remain in effect until the Secretary has issued or denied the operating permit renewal. However, this Operating Permit shall automatically expire if, subsequent to the renewal application being determined or deemed administratively complete pursuant to §5-1006 of the Regulations, Okemo fails to submit any additional information required by the Secretary as well as information pertaining to changes to the Facility within thirty (30) days or such other period as specified in writing by the Secretary. [Sections 5-1005(c) and 5-1012 of the *Regulations*]

(47) The Operating Permit shall expire five (5) years from the date of its issuance. [§5-1011 of the *Regulations*]

The Agency's issuance of this Air Pollution Control Permit to Construct and Operate relies upon the data, judgement, and other information supplied by Okemo. The Agency makes no assurances that the air contaminant source approved herein will meet performance objectives or vendor guarantees supplied to the source owner/operator. It is the sole responsibility of Okemo to operate the source in accordance with the conditions herein and with all applicable state and federal standards and regulations.

Dated this _______ day of _______________________________, 2000, in the town of Waterbury, county of Washington, state of Vermont.

Agency of Natural Resources

Canute Dalmasse, Commissioner
Department of Environmental Conservation

By: ________________________________
Richard A. Valentinetti, Director
Air Pollution Control Division

SLL/sll
A2:Okemo Mountain. Ludlow

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PERMIT TO OPERATE

GREAT BASIN UNIFIED AIR POLLUTION CONTROL DISTRICT
157 Short Street ★ Bishop, California 93514 ★ (760) 872-8211 ★ Fax (760) 872-6109

PERMIT №: 796

Pursuant to the authority granted under Rule 209-B of the Rules and Regulations for the Great Basin Unified Air Pollution Control District, the

CR Briggs Corporation
Post Office Box 668
Trona, California 93592

is hereby granted a **Permit to Operate** as of June 16, 1997, for the following described operations, associated equipment and buildings located at: Commonly known as the CR Briggs Project. Located approximately 8 miles south of the town of Ballarat on the east side of the Wingate Road, Panamint Valley.

This Permit to Operate is granted for one year and shall be renewed upon payment of the renewal fee on or before the stated anniversary date. Note: For permit renewal purposes, the anniversary date is June 18, 1996, the date when the Temporary Permit to Operate was originally issued.

OPERATION, EQUIPMENT, FOR PERMIT: Mine electricity generation plant, consisting of:
4 - CATERPILLAR© Model 3514 Diesel generator sets rated @ 1600 hp ea. Each diesel engine drives a 60hz prime power generator set rated @ 1100 KWe continuous duty 6400 hp
1 - 25,000 gallon capacity aboveground diesel fuel storage tank

CONTROL SYSTEM:
1 - selective catalytic reduction (SCR) unit.
1 - ammonia chemical holding tank (pressurized, permit fee exempt) 10,000 gallon
Diesel fuel storage tank is painted white or light reflective

CONDITIONS: This Permit to Operate is subject to the attached conditional approval 1 through 14.

ois permit does not authorize the above permittee to
iolate any of the Rules and Regulations of the Great Basin
nified Air Pollution Control District or Division 26,
ap r 2, Article 3, of the Health & Safety Code of the
tat of California.

AIR POLLUTION CONTROL OFFICER

Date June 16, 1997

Note: For permit renewal purposes, the anniversary date is the date the Temporary Permit to Operate was originally issued.

CONDITIONAL APPROVAL for PERMIT TO OPERATE № 796

Mine electricity generation plant
CR Briggs Corporation
14142 Denver West Parkway, Suite 250
Golden, Colorado, 80401

ALL GENERAL PERMIT CONDITIONS 1 THROUGH 12 CONTAINED IN PERMIT NUMBER 793 ARE INCLUDED BY REFERENCE INTO THIS PERMIT.

1) The mine electricity generation plant shall be installed according to the design specification submitted with the Authority to Construct application. CR Briggs Corporation shall formally notify the District in writing when construction is complete and the equipment is ready for inspection. Written start-up notification shall be delivered to the District office by Postal Service delivery or facsimile transmission at least 48 hours prior to equipment start-up. Operation of this equipment without a written Permit to Operate is a violation of District Rule 200-B, and can result in civil and criminal penalties (Cal H&S Code § 42400). [Origin of Condition: District Rule 200-B].

2) A selective catalytic reduction (SCR) NO_X control system shall be installed on the electric generator plant and operated to achieve compliance with the terms and conditions of this permit. This selective catalytic reduction (SCR) system shall be permanently installed with each generator exhaust pipe manifolded into one common exhaust stack. Operation of the electric generator plant shall be limited to the maximum production rates, schedules of operation, and process material as specified in the Authority to Construct application. This control unit shall at all times be maintained in good working order and operated as efficiently as technically feasible. ~~possible to provide NO_X stack reductions of at least 80% percent.~~ Following the installation of the SCR unit, hourly nitrogen dioxide emissions shall be limited to a maximum of 27.2 pounds per hour. On an annual basis, nitrogen dioxide NO_X emissions shall be limited to 89.3 tons. [Origin of Condition: District Rule 216, NSR]. *Revised 6/16/97*

3) A flow meter indicating the accumulated fuel consumption, in gallons, shall be installed in the fuel supply line to the engines. Diesel fuel flow rate shall be properly metered and logged daily. These records shall be maintained at the CR Briggs field office and made available to District Staff upon request. These records shall be kept available for a period of two years [Origin of Condition: District Rule 206].

4) The amount of sulfur dioxide exhausted to the atmosphere shall not exceed 0.2% by volume. [Origin of Condition: District Rule 416].

5) Exhaust stack visible emissions shall not exceed a Ringelmann 1 (20% opacity) for a period or periods aggregating more than three minutes in any one hour [Origin of Condition: District Rule 400].

6) Ammonia escaping from (slip rate) the catalytic converter shall not exceed 50 ppm_v corrected to 15% oxygen [Origin of Condition: District Rule 210.A].

7) The applicant shall keep a sufficient supply of industrial grade ammonia gas on hand to allow for immediate system replenishment. If another reagent other than industrial grade ammonia is chosen for use as the reaction medium, the APCO shall review the request and give written approval prior to its use. [Origin of Condition: District Rule 210.A].

8) An in line continuous emission monitoring (CEM) device shall be installed to continuously measure NO_X emissions released to the atmosphere. With this instrument, the applicant shall record the hourly average NO_X stack emissions in parts per million (ppm_v) at all operating times when the exhaust temperature is sufficient for catalytic NO_X reduction. At operating times when exhaust temperature is insufficient for catalytic NO_X reduction the CEM system shall calculate NO_X emissions for the NO_X emissions curve given below and shall record hourly NO_X emissions in pounds per hour.

$$y = 0.02355(x) + 14.98 \text{ for } x \geq 550 \text{ KWe, or}$$
$$y = 0.04922(x) + 0.862 \text{ for } x < 550 \text{ KWe,}$$

Where:

y = NO_X *emissions per engine (lbs/hr), and*
x = *engine output per engine (KWe)*

Real-time generator output (in BHP for each generator), NO_X emissions (in ppm_v and pounds per hour), and ammonia flow (in pounds per hour) shall be displayed on the CEM computer system so that this information may be readily inspected by District staff. Excess emissions indicated by the CEM system shall be considered violations of the applicable emissions limit for the purposes of this permit. These emissions records shall be kept for two years and will be made available to the District staff on a quarterly calendar basis. In addition to the District's performance specification, the selected NO_X monitor shall be capable of meeting the performance specifications described in [40 CFR 60, Appendix B, Performance Specification 2]. [Origin of Condition: District Rule 206, Table I.A]. ***Revised 6/16/97***

9) The selected NO_X CEM shall be properly maintained and the CEM serviced (zeroed & spanned) at least twice monthly. On a semi-annual basis, the applicant shall check the monitor's accuracy by performing a multipoint precision calibration. Plant operators shall submit for District approval a quality assurance plan describing the calibration procedures necessary to accurately collect data and measure the NO_X emission limits. [Origin of Condition: District Rule 206].

10) It is CR Briggs responsibility to continually record and monitor the exhaust flow rate and the hourly average NO_X emission (in pounds per hour) emitted from the SCR system. The electric generation plant operator(s) shall inform the District staff of any monitor breakdown by the procedures outlined in condition 5 of ATC 793. [Origin of Condition: District Rules 210.A & 403].

11) Each *volatile organic liquid* (VOL) storage tank with a holding capacity greater than 40 cubic meters (10,566 gallons), shall comply with the record keeping requirements of [40 CFR Part 60.116b(b)]. In meeting this directive, the applicant shall clearly label each tank's dimensions, storage capacity, and its VOL contents. [Origin of Condition: District Regulation IX].

CARB Method 430	Source testing procedure for determining formaldehyde emissions from stationary sources.
ASTM Method D808-87	Standard Test Method for Chlorine in New and Used Petroleum Products (Bomb Method).
ASTM Method D129-64	Standard Test Method for Sulfur in Petroleum Products (general Bomb Method).

14) The SCR system shall be operated at all times except under breakdown conditions (Permit Nº 793, condition 5) and during regularly scheduled maintenance activities as recommended by the manufacturer. CR Briggs plant operator(s) shall not emit untreated exhaust gas from more than one diesel engine at any time. If the maintenance activity continues for more than one day, a breakdown event shall be reported by the procedures outlined in Permit Nº 793, condition 5 [Origin of Condition: District Rule 403]. *Revised 6/16/97*

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DeNOx Systems

Reference list (Page 1 of 7)

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Nixdorf Computer AG, Paderborn (D)	Cogen facility	3	natural gas	3 x 1.000	6.500 each	> 85	DeNOx-Cat	12 / 1983
Stadtwerke Dreieich (D)	Cogen facility	5	natural gas	5 x 155	687 each	85	DeNOx-Cat	03 / 1985
MAN, Munich (D)	Cogen facility	1	natural gas	80	380	90	DeNOx-Cat	03 / 1985
Chemical Industrie (D)	calcination plant	1	-	-	3000	>90	DeNOx-Cat	03 / 1985
VEW, Dortmund (D)	Coal-fired power plant	1	coal	-	10,000	> 85	DeNOx-Cat	02 / 1985
University Hamburg / Harburg (D)	Cogen facility	4	natural gas	4 x 750	2 x 3.900 2 x 5.200	85	DeNOx-Cat	10 / 1985
Community of Heidelheim (D)	Cogen facility	1	Diesel	75	350	90	DeNOx-Cat	07 / 1985
Nixdorf-Computer AG, Paderborn (D)	Cogen facility	2	natural gas	3 x 1.500	9.500 each	> 85	DeNOx-Cat	12 / 1985
Community of Norderstedt (D)	Cogen facility	6	natural gas	6 x 750	3.700 each	> 85	DeNOx-Cat	09 / 1985
VBH, Heligoland Island (D)	Cogen facility	1	heavy oil	6,000	30,000	> 90	DeNOx-Cat	12 / 1989
Schott, Mainz (D)	glass melting furnace	1		-	5,000	> 80	DeNOx-Cat	10 / 1985
RWE, Essen (D)	Coal-fired power plant	1	brown coal	-	5,000	> 80	DeNOx-Cat	07 / 1985
Community of Bad Oeyenhausen (D)	Cogen facility	2	natural gas	2 x 750	5.000 each	> 90	DeNOx-Cat	11 / 1985
Klöckner-Humboldt-Deutz AG, Cologne (D)	Cogen facility	1	diesel-gas	60	250	> 90	DeNOx-Cat	10 / 1985
Bank house of lower Saxony, Hannover (D)	Cogen facility	1	diesel-gas	625	3,370	> 85	DeNOx-Cat Oxidation Cat	03 / 1986

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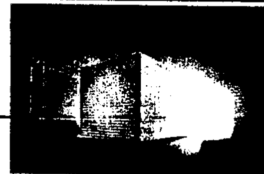
DeNOx Systems



Reference list (Page 2 of 7)

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Oberlandglas AG, Neuburg a.d.D. (D)	glass melting furnace	1	-	-	50,000	80	DeNOx-Cat	10 / 1987
Peißenberg utilities, Peißenberg (D)	cogen facility	1	diesel-gas	6,100	34,000	90	DeNOx-Cat	11 / 1987
Sewage plant II, Munich (D)	cogen facility	5	diesel-gas	5 x 1.750	8.900 each	85	DeNOx-Cat	05 / 1990
Bank House, Basel (CH)	cogen facility	2	diesel-gas	2 x 625	3.450 each	9	DeNOx-Cat Oxidation Cat	02 / 1988
Sewage plant, Delmenhorst (D)	cogen facility	1	natural gas	300	1,370	88	DeNOx-Cat	02 / 1988
Depogas, Berlin (D)	cogen facility	3	landfill gas	3 x 1500	6.357 each	85	DeNOx-Cat	02 / 1988
Speno International S.A., Geneva (CH)	engine on a work train	1	diesel-gas	600	2,680	80	DeNOx-Cat	03 / 1998
Community of Gelsenkirchen (D)	cogen facility	2	diesel-gas	5.100 each	26.500 each	95	DeNOx-Cat Oxidation Cat	09 / 1988
Pfizer, Adams (MA, USA)	cogen facility	1	diesel-gas	5000	27,000	95	DeNOx-Cat	09 / 1988
Chemical industry, Beaumont, (TX, USA)	calcination plant	2	-	-	25,000	99	DeNOx-Cat Oxidation Cat	11 / 1989
Mobil Oil, San Ardo, (CA, USA)	gas turbine	2	natural gas	2 x 3300	54.000 each	65	DeNOx-Cat	04 / 1989
Speno International S.A., Geneva (CH)	engine on a work train	1	diesel-gas	600	2,680	80	DeNOx-Cat Oxidation Cat	07 / 1989
Mobil Oil, Belridge (CA, USA)	gas turbine	3	natural gas	3 x 3300	54.000 each	80	DeNOx-Cat	11 / 1989
Peißenberg utilities, Peißenberg (D)	cogen facility	1	diesel-gas	6100	34,000	90	DeNOx-Cat	02 /1990
DEA, Wolfersberg (D)	gas compressor station	1	natural gas	1,700	13,400	92	DeNOx-Cat Oxidation Cat	01 / 1990

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DeNOx Systems

Reference list 07 (page 3 of 7)

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Cement industry, Chien Tai (Taiwan)	cogen facility	3	heavy fuel oil	3 x 7.100	37.700 each	84	DeNOx-Cat	10 / 1991
Public utility, Järvenpää (Finland)	cogen facility	1	diesel-gas	7,100	41,700	90	DeNOx-Cat	07 / 1990
Bank house, Basel (CH)	cogen facility	1	diesel-gas	625	3,700	90	DeNOx-Cat	05 /1990
Nordenia, Steinfeld (D)	cogen facility	1	diesel-gas	5,100	26,480	65	DeNOx-Cat Oxidation Cat	09 /1990
NEAG, Großenkneten (D)	gas compressor station	2	natural-gas	2 x 1.500	11.750 each	94	DeNOx-Cat Oxidation Cat	08 / 1990
Mobil Oil, Siedenburg-W / E (D)	gas compressor station	6	natural-gas	6 x 1000	7.000 each	88	DeNOx-Cat Oxidation Cat	04 / 1991
Mobil Oil, Barenburg (D)	gas compressor station	1	natural-gas	1,000	7,000	88	DeNOx-Cat Oxidation Cat	02 / 1991
Mobil Oil, Wolfersberg (D)	gas compressor station	5	natural-gas	5 x 1.700	13.400 each	92	DeNOx-Cat Oxidation Cat	01 / 1991
Outokumpu Oy Polarit, Tornio (Finland)	stainless steel pickling line	1	-	-	3,000	95	DeNOx-Cat	03 / 1991
Saar Ferngas, Frankenthal (D)	gas compressor station	2	natural-gas	2 x 1.000	5.900 each	87	DeNOx-Cat Oxidation Cat	03 / 1991
Speno International S.A., Geneva (CH)	engine on a work train	1	diesel-gas	6000	2,680	80	DeNOx-Cat OXI Cat	05 / 1991
Public utility, Linköping (Sweden)	cogen facility	2	heavy fuel oil	2 x 7.100	45.500 each	93	DeNOx-Cat	08 / 1991
Nato Navy Port, Den Helder (NL)	cogen facility	3	dual fuel	3 x 5.100	21.000 each	87	DeNOx-Cat	04 / 1992
NEAG, Großenkneten (D)	gas compressor station	1	natural-gas	1,500	11,750	94	DeNOx-Cat Oxidation Cat	08 / 1991
Krupp Stahl AG, facility Düsseldorf-Benrath (D)	pickling line	1	-	-	21.000	94	DeNOx-Cat	01 / 1992

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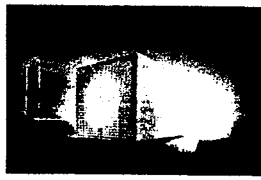

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Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
NEAG, Sulingen (D)	gas compressor station	2	natural-gas	2 x 1.500	11.750 each	90	DeNOx-Cat Oxidation Cat	08 / 1992
Idemitsu, Osaka (Japan)	cogen facility	1	diesel-gas	800	4.500	90	DeNOx-Cat	04 / 1992
VAW, Bonn (D)	recycling research plant	1	-	-	3.000	90	DeNOx-Cat	08 / 1993
Krupp Stahl AG, facility Dillenburg (D)	pickling line	1	-	-	19.000	97	DeNOx-Cat	04 / 1994
LACSD, Los Angeles (USA)	cogen facility	3	sewage-gas	3 x 10.000	125.000 each	85	DeNOx-Cat	06 / 1995
Vaasa Kraftwerke, Stendal (D)	cogen facility	3	diesel-gas	3 x 7.900	39.600 each	81	DeNOx-Cat	05 / 1994
Nippon Oil Co., LTD, Yokohama (Japan)	cogen facility	1	diesel	200	1.255	90	DeNOx-Cat	04 / 1994
Outokumpu Oy Polorit, Tornio (Finland)	pickling line	1	-	-	9.000	98	DeNOx-Cat	11 / 1994
Tosco Refinery, Martinez (USA)	compressor station	1	natural-gas	750	5.200	86	DeNOx-Cat	09 / 1994
Columbus Joint Venture 1, (RSA)	pickling line	1	-	-	6.000	93	DeNOx-Cat	09 / 1994
Coltec Ind. / Fairbanks Morse Engine Div., (USA)	cogen facility	1	diesel-gas	2,500	13.800	90	DeNOx-Cat	04 / 1995
Hsin Shih, (Taiwan)	cogen facility	1	heavy fuel oil	7,100	36.200	> 84	DeNOx-Cat	06 / 1995
Ma Tou, (Taiwan)	cogen facility	2	heavy fuel oil	2 x 4.000	24.300 each	87	DeNOx-Cat	07 / 1995
Takuma Co., Ltd., Osaka (Japan)	stainless steel industry							
Schütz, Selters (D)	cogen facility	2	diesel	2 x 500	2.100 each	60	DeNOx-Cat	05 / 1995

Reference list 07 (page 5 of 7)

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Schütz, Selters (D)	cogen facility	1	diesel	500	2,100	65	DeNOx-Cat	06 / 1995
EWR Calbe, Calbe (D)	cogen facility	2	diesel-gas	2 x 5.200	28.820 each	92	DeNOx-Cat	12 / 1995
DEA refinery, Hamburg-Grasbrook (D)	boiler	3	heavy fuel oil	-	23.150 each	77	DeNOx-Cat	02 / 96
Socofer, Tours (France)	engine on a work train	4	diesel	4 x 250	1.680 each	> 80	DeNOx-Cat Oxidation Cat	01 / 1996
Chem Y GmbH, Emmerich (D)	incineration process	1	-	-	5,800	89	DeNOx-Cat	01 / 1996
BASF, Antwerpen (Belgium)	incineration process	1	-	-	4,800	75	DeNOx-Cat	04 / 1996
Columbus Joint Venture, RSA (South Africa)	pickling line	1	-	-	6,000	97	DeNOx-Cat	06 / 1996
Great Lakes Dredge & Dock, Ok Brook (IL, USA)	dredger barge	1	diesel	300	1,900	80	DeNOx-Cat	12 / 1995
Outokumpu Oy Polorit, Tornio (Finland)	stainless steel pickling line	1	-	-	6,000	96	DeNOx-Cat	09 / 1996
Stadtwerke Zittau, Zittau (D)	cogen facility	2	diesel-gas	2 x 2.500	14.410 each	92	DeNOx-Cat Oxidation Cat	11 / 1996
Staten Island University Hospital, New York (USA)	cogen facility	1	diesel-gas	3,500	19,500	90	DeNOx-Cat	06 / 1996
W.C. Heraeus, Hanau (D)	incineration plant	1	-	-	3,000	not o be published	combined Cat Dioxine / NOx	09 / 1996
Tosco Refinery, Martinez (USA)	compressor station	5	natural-gas	5 x 750	5.200 each	86	DeNOx-Cat	12 / 1996
Guschall, Etzbach (D)	cogen facility	2	diesel	2 x 1.250	6.200 each	> 87	DeNOx-Cat	03 / 1997

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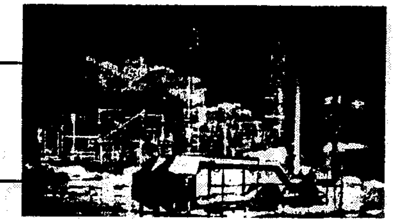

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Sammi Steel, (South Corea)	stainless steel pickling line	1	-	-	4,500	96	DeNOx-Cat	04 / 1999
Carl Schäfer, Pforzheim (D)	waste incineration plant	1	-	-	800	> 63	Dioxine-Cat	11 / 1996
Carl Schäfer, Pforzheim (D)	waste incineration plant	1	-	-	2,400	> 75	Dioxine-Cat	02 / 1997
Lane Construction, Lee (MA, USA)	cogen facility	1	diesel-gas	1,000	7,370	91	DeNOx-Cat	06 / 1997
Thermoselect, Karlsruhe (D)	waste incineration plant	2	-	-	46.000 each	> 90	DeNOx-Cat	05 / 1998
Mountain Utilities, Kirkwood (CA, USA)	power plant	1	diesel-gas	4,800	25,000	90	DeNOx-Cat	10 / 1997
Barrick Goldstrike Mines, Inc., Barrick (USA)	roasting process	1	-	-	34,500	75	DeNOx-Cat	07 / 1999
Crematorium, Nuernberg (D)	crematorium	4	-	-	2.500 each	> 96	Dioxine-Cat	12 / 1998
BHKW Boulder City (Nevada, USA)	cogen facility	3	diesel-gas	3 x 175	1.750 each	> 80	DeNOx-Cat Oxidation Cat	07 / 1998
Boeringer, Mannheim (D)	incineration plant	1	-	-	4,000	> 98	Dioxine-Cat	09 / 1998
Catamaran (Norway)	Propulsion	4	diesel-gas	4 x 800	4.065 each	> 80	DeNOx-Cat	12 / 1998
Southworth-Milton, Boston (MA, USA)	car shredder	1	diesel-gas	1,000	6,000	> 80	DeNOx-Cat	10 / 1998
Great Lakes Dredge & Dock, Ok Brook (IL, USA)	dredger barge	4	diesel-gas	3,500	3 x 6.000 1 x 2.540	> 80	DeNOx-Cat	12 / 1998
Rhone Poulenc (France)	waste incineration plant	1	-	-	120,000	> 90	DeNOx-Cat	08 / 1998
Avesta Sheffield, (Sweden)	stainless steel pickling line	1	[illegible]	[illegible]	7,000	> 98	DeNOx-Cat	10 / 1998

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DeNOx Systems

Reference list (Page 7 of 7)

Customer / Operator	Field of application	Number of reactors	Combustible	Capacity [kW]	Volume Flow [Nm^3/h]	NOx reduction rate [%]	Scope of supply	Commis-sioning
Ostseebad Damp, Damp (D)	cogen facility	1	diesel	500	2,600	> 50	DeNOx-Cat	10 / 1998
Supply ship, (Norway)	Propulsion	1	diesel	1,000	5,800	> 85	DeNOX-Cat	03 / 1999
Socofer, Tours (France)	engine on a work train	4	diesel	4 x 250	1.680 each	> 80	DeNOx-Cat Oxidation Cat	01 / 2000
Carl Schäfer, Pforzheim (D)	waste incineration plant	1	-	-	1,200	> 99	Dioxine-Cat	03 / 1999
Gewerbepark Zittau (D)	cogen facility	4	bio-diesel	4 x 150	1.654 each	> 91	DeNOx-Cat	04 / 1999
Yieh United Co. Ltd., (Taiwan)	stainless steel pickling line	1	-	-	15,000	95 - 97	DeNOX-Cat	05 / 2000
Yieh United Co. Ltd., (Taiwan)	stainless steel pickling line	1	-	-	32,000	97	DeNOx-Cat	05 / 2000
EniChem	waste incineration plant	1	chlorinated wastes	-	13,120	> 99	Dioxine-Cat	10 / 2000
Yieh United Co. Ltd., (Taiwan)	mixed acid recovery	1	-	-	12,000	95 - 97	DeNOx-Cat	11 / 2000
Avesta Sheffield Ltd., (UK)	stainless steel pickling line	1	-	-	24,000	> 97	DeNOX-Cat	01 / 2001

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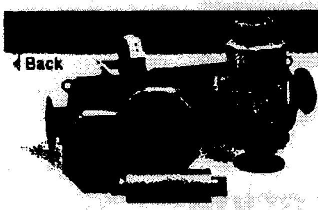

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MIRATECH SCR Corporation

SCR NOx Abatement System

1. Brief Description

The exhaust gases from diesel engines containing oxides of nitrogen (NOx); carbon monoxide (CO) and volatile organic compounds (VOC) are directly transferred to the SCR catalytic reactor. A 40% aqueous solution of urea is added as reducing agent (SCR technique). With more than 700 commercial plants in operation worldwide, substantial field experience is available to validate designs and provide field assistance.

2. Main Components

- Reactor with ceramic honeycombs
- Reducing agent dosing and injection system
- Ammonia storage tanks and pumps (not included in our scope of supply)

2.1 Reactor

The reactor is made of either carbon or stainless steel (type 304). The reactor should be insulated. Insulation can be field applied by the customer, or can be factory installed. There are top access doors to each catalyst layer to allow for easy inspection of the reactor and catalyst layer(s).

2.2 Reducing Agent

Urea in the form of a 40% aqueous solution in de-ionized water is used in these systems.

3. NOx Reduction

The reduction stage consists of a monolith type catalyst section. The honeycomb elements are extruded ceramic material and coated with active materials including tungsten and vanadium oxides (material specification will not be given before the order). During the process, oxygen, oxides of nitrogen, and ammonia penetrate the fine pores of the catalyst and react on the active centers. The products of the reaction are nitrogen and water.

3.1 Side Reaction: HC conversion

Some of the hydrocarbons in the exhaust gas are oxidized on the SCR catalyst into water and CO. This means that, after the SCR stage, the amount of CO could increase in a given application. An oxidation catalyst is provided to reduce CO emissions, hydrocarbons, and any ammonia slip.

4. Injection

The urea solution is spray-injected into the center of the hot exhaust stream where it hydrolyzes in an extremely short period of time. Special dual media injectors were designed to aid mixing and purge feed lines.

CATALYST SYSTEMS

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MIRATECH SCR Catalytic Converters

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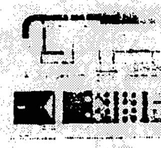

MIRATECH SCR Catalytic Converters

The HUG SCR Catalytic Converter from MIRATECH. It's the most efficient and technologically advanced choice for handling combustion system exhaust gases.

With over 22 patent applications, there's no other SCR converter that offers technology at this level. Our SCR catalytic converters reduce pollutants for any diesel, dual-fuel or lean-burn gas engines. MIRATECH's SCR reduces regulated pollutants produced from the combustion of fossil fuels in engines such as oxides of nitrogen, carbon monoxide, sulfur dioxide and unburned hydrocarbons (VOC's). Applications vary widely and include power generation, gas compression, liquids pumping, Greenhouse CO2 augmentation and marine propulsion.

When your ready to get serious about compliance and reduced emissions, turn to the experts at MIRATECH. We've performed over 700 installations, far more than the competition.

Pioneers in engineering. Leaders in technology. MIRATECH provides you with the tools to effectively reduce harmful emissions, costs and risk of noncompliance. SCR converters from a name you've learned to trust - MIRATECH.

FEATURES AND BENEFITS

Our SCR catalysts work in two efficient stages: NOx reduction and oxidation stage (for combustion of CO and HC). Both stages work together, drastically reducing harmful emissions and easily satisfying exhaust gas regulations over a long period of time.

MIRATECH SCR catalytic converters help you do so much more than just meet strict regulations. They can help reduce pollutants drawn in by air intakes located too close to diesel exhaust as well as create reliable and efficient heat recovery by decreasing the fouling rate of your tubes. You'll be surprised at the reduction in noise, too. SCR converters can reduce engine noise by up to 35 DBA.

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With MIRATECH you don't have to mess with complex controls assembly. Our panels come preassembled and include PLC – Programable Logic Controller. All SCR converters come with purge lines and an air assisted injection nozzle to create efficient atomization. MIRATECH allows you to have a higher level of operations control with our electrochemical analyzing package. You'll get feedback and monitoring, giving you control that's unique to the industry. MIRATECH SCR converters use urea as well traditional ammonia for reducing nitrogen oxide levels in combustion diesel exhaust gases. Urea is not only cheaper, it offers advantages in transport, storing and handling.

FEATURES AND BENEFITS

- Packaged controls includes urea and air pump.
- Simple and quick bulk head connections for wiring and plumbing.
- Safety shutdown and alarm controls.
- Specified urea or ammonia operation.
- Atomizing injector with air purge for urea or ammonia.
- Easy access to injector for cleaning and maintenance.
- Carbon or stainless steel catalyst housing.
- Insulation package with aluminum or galvanized steel sheathing.
- Catalast access door for easy service and maintenance.
- Fiberglass socks gasket and protects unitized catalyst modules.
- High-activity tungsten/vandia catalyst.

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In our injector the reducing agent is atomized with pressurized air. The air is also used to insulate and cool the injector. Whenever the injection is turned off the compressed air is blown through the reducing agent path to ensure that no reducing agent remains in the injector. The three-way valve on top of the injectors is electrically driven and its position is constantly monitored. A compressor located in the control cabinet produces the compressed air.

5. Mixture of Reducing Agent with Exhaust Gas

After the urea is fully hydrolyzed it must be distributed uniformly over the cross section of the exhaust duct. The mixing pipe is needed for homogeneous mixing of the reducing agent with the exhaust gas.. The mixers are provided loose and must be welded into the pipe by others.

6. Reducing Agent Injection and Control System

6.1 Injection Rate of Reducing Agent

For NOx reduction the reducing agent must be injected as a function of the NOx mass flow. At commissioning, the NOx production versus engine load is measured and programmed into the PLC, providing injection rates as a function of engine load. This system is most cost efficient and ensures easiest handling. Except for periodic checks (every 6 months); no maintenance is typically required.

6.2 Control System

The PLC system controls all required functions of the SCR system.

6.3 Control System (hydraulic, integrated in PLC Panel)

All mechanical components for the reducing agent metering and the injector air monitoring are mounted in a standard sheet metal cabinet. Electrical cables are fed through the top of the cabinets, and hydraulic and pneumatic connections are arranged on one side of the cabinet (normally on the right).

6.4 Optional NO Monitoring/Feedback System

An optional NO monitoring system with feedback can be supplied. The system consists of chemical cell NO analyzer(s), sample conditioning system, sample probe, PLC, and miscellaneous pilot control components. The NO after the SCR stage is compared to the desired NO level, and the urea injection rate is adjusted up or down to maintain this value. The system still uses the engine load/urea injection map described above to make rapid adjustments for load swings.

The system monitors NO directly downstream of the SCR stage, and again directly after the Oxidation stage. By comparing the NO differential, the system can determine if there is excessive ammonia slip and react accordingly.

Optionally, the system can be equipped with CO monitoring cells, analog outputs, and a modem (which allows for dial-up access to the system for troubleshooting and monitoring purposes).

For systems with NOx removal efficiency greater than 90%, or guaranteed NOx values less than 10 ppmvd, a NO Monitoring/Feedback System is required.

MIRATECH SCR PROJECTS IN NORTH AMERICA
April, 2001

Project/User Name	Fuel	Engine Mfg	Engine Model	# of Engines	Power Rating (kW)	Installed Power (kW)	Application/ Location	Commission Date
Rosa Flora Greenhouse	Natural Gas	Caterpillar	3516LE	1	800	800	CoGeneration Dunnville, ONT	1995
Southworth Milton	Diesel	Caterpillar	3406DITA	1	400	400	Genset/Rock Crusher Portable - New England sites	1998
Foley/IFF	Natural Gas	Caterpillar	3612	1	2200	2,200	Genset Dayton, NJ	2000
Southworth Milton/Okemo	Diesel	Caterpillar	3516DITA	1	1250	1,250	Air Compressor (IR) Ludlow, VT	2000
Southworth Milton/Mill River	Diesel	Caterpillar	3412C DITA	1	800	800	Genset w/ Air:Air Heat Exchanger North Clarendon, VT	2000
Darr/Willams Telecommunications	Diesel	Caterpillar	3516B DITA	1	2000	2,000	Genset New York, NY	2001
Stewart & Stevenson / Chow II	Natural Gas	Deutz	TGB632	16	3100	49,600	Peak Shaving Gensets/Chowchilla, CA	2001
Stewart & Stevenson / Red Bluff	Natural Gas	Wartsila	18V220SG	16	2850	45,600	Peak Shaving Gensets/Red Bluff, CA	2001
GE/Spartech	Natural Gas	Jenbacher	JMS616 G.S.-N.L.	2	1912	3,824	Cogen Plant/ La Mirada, CA	2001
GE/Tesoro	Natural Gas	Jenbacher	JMS320 G.S.-N.L.	18	1095	19,710	Gensets/ Anacortes,WA	2001
Stewart & Stevenson / Corona	Natural Gas	Wartsila	18V220SG	2	2850	5,700	Peak Shaving Gensets/Corona, CA	2001

HUG ENGINEERING

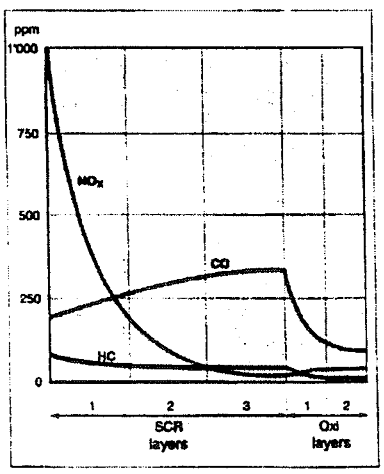
CATALYTIC POLLUTION CONTROL EQUIPMENT

1) SCR (DeNOx) reactors, urea or ammonia based;

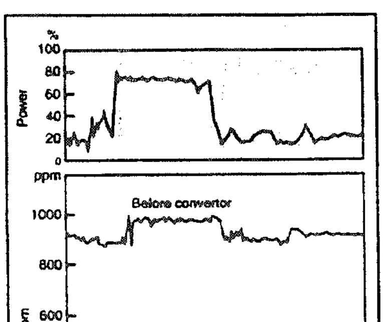
2) Oxydation reactors;

3) Catalytic soot traps / filters,

for diesel and gas engines ranging from several kW up to 20MW electrical power.



Typical curves for NOx, HC and CO concentrations in pollution abatement reactors utilizing HUG Engineering's pioneer technology. **NOx** emission levels **below 25 mg NOx per normal cubic meter** exhaust gas are more a rule than an exception.



Typical transient behaviour for ferries, where short periods of high engine load are followed by periods of near-idle load of the engines. Unsteady engine loads are handled through HUG Engineering's control technology, where reactant injection (urea or ammonia) is correlated to the

	engine load signal.

DANKE fuer's Vorbeischauen / THANK YOU for logging in

Hug Engineering documents page #3 of 4 (english);

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No.	el. power kw	engine/vehicle	type	type of use	type of application	burner	filter	SCR	OXI	customer	country	year of order
1	700	MTU	8V 396 TB34 R	emergency generator	241			X	X	Klinik Ste. Thérèse	L	1996
2	700	MTU	8V 396 TB34 R	emergency generator	241			X	X	Klinik Ste. Thérèse	L	1996
3	510	MWM	TBD 234 V12	power	241	X	X	X	X	Carnuth	D	1995
4	510	MTU	12V 183TB322	emergency generator	241			X	X	Centre Hospitalier Luxenburg	L	1995
5	510	MTU	12V 183TB322	emergency generator	241			X	X	Centre Hospitalier Luxenburg	L	1995
6	441	DB	OM 444 LA	heat power	241		X	X	X	Edel Landtechnik	D	1996
7	500	Perkins	3012 TAG 1A	power	241			X	X	GEC / Yverdon	CH	1997
8	434	MAN	D2842 LE	emergency generator	241			X	X	Foyer	L	1996
9	480	MTU	8V 396 TB34	emergency generator	241		X	X	X	BIL	L	1997
10	480	MTU	8V 396 TB34	emergency generator	241		X	X	X	BIL	L	1997
11	500	Perkins	3012 TAG 1A	emergency generator	241			X	X	Rode Klinik am Eichert	D	1997
12	443	MAN	D2142 LE21	emergency generator	241			X	X	Pall Center	L	1997
13	550	MWM	TBD 604 NBL6	peak shaving / emergency	241		X			Krankenhaus Itzenhoe	D	1998
14	550	MWM	TBD 604 NBL6	peak shaving / emergency	241		X			Krankenhaus Itzenhoe	D	1998
15	545	MTU	12V 2000 G60	emergency generator	241			X	X	S.E.S	L	1998
16	500	Waukesha	L36GLD	heat power	241			X	X	Psych. Klinik Königsfelden	CH	1998
17	634	MAN	D2842 LE 203	emergency generator	241			X	X	Cactus Ingeldorf	L	1998
18	400	Caterpiller	3412TA	power	217		X		X	Granitwerke Wildtier	D	1995
19	360	MTU	Daimler Benz	heat power	187		X	X	X	GLG Energieanlagen	D	1995
20	360	MTU	Daimler Benz	heat power	187		X	X	X	GLG Energieanlagen	D	1995
21	360	MTU	Daimler Benz	heat power	187		X	X	X	GLG Energieanlagen	D	1995
22	305	MWM	TBD 234 V8	power	187	X	X	X	X	Carnuth	D	1995
23	434	MAN	D2842 LE	power	187		X	X	X	Guschall Nr. 1	D	1995
24	434	MAN	D2842 LE	power	187		X	X	X	Guschall Nr. 1	D	1995
25	434	MAN	D2842 LE	power	187		X	X	X	Guschall Nr. 2	D	1995
26	434	MAN	D2842 LE	power	187		X	X	X	Guschall Nr. 2	D	1995
27	434	MAN	D2842 LE	power	187		X	X	X	Guschall Nr. 3	D	1996
28	252	MWM / Deutz	TBG 234 V12	heat power	187			X	X	Morettina	CH	1996
29	700	MTU	8V 396 TB34	emergency generator	187			X	X	KBL	L	1996
30	700	MTU	8V 396 TB34	emergency generator	187			X	X	KBL	L	1996
31	350	MWM	TBG 616 V8K	heat power (nature gas)	187			X	X	Radrennbahn Berlin	D	1996
32	350	MWM	TBG 616 V8K	heat power (nature gas)	187			X	X	Radrennbahn Berlin	D	1996
33	350	MWM	TBG 616 V8K	heat power (nature gas)	187			X	X	Radrennbahn Berlin	D	1996
34	292	Caterpiller	3406C TA	heat power	187			X	X	Fuchs	A	1997
35	449	MAN	D2842 LE	heat power	187			X	X	Cegedel	L	1997

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No.	el. power kw	engine/vehicle	type	type of use	type of application	burner	filter	SCR	OXI	customer	country	year of order
36	449	MAN	D2842 LE	heat power	187			X	X	Cegedel	L	1997
37	449	MAN	D2842 LE	heat power	187			X	X	Cegedel	L	1997
38	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
39	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
40	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
41	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
42	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
43	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
44	258	MAN	E2842 LN	heat power	187			X	X	PKA Aalen	D	1997
45	365	Caterpiller	3406 DITA	power	187				X	Rock Crusher	USA	1997
46	400	MAN	D2842 LE21	peak shaving	187			X	X	Post PTT	L	1998
47	400	MAN	D2842 LE21	peak shaving	187			X	X	Post PTT	L	1998
48	400	MAN	D2842 LE21	peak shaving	187			X	X	Post PTT	L	1998
49	400	MAN	D2842 LE21	heat power	187			X	X	Cactus	L	1998
50	400	MTU	12V183 TB32L	heat power	187			X	X	Cactus	L	1998
51	250	MTU	8V 183 TA 32	power	127				X	Croix Rouge	L	1995
52	246	Deutz	KHD 8M 716	peak shaving / emergency	127		X			Krankenhaus Itzenhoe	D	1998
53	300	MAN	2542 MLE	peak shaving	127		X			Diakonie Bad Kreuznach	D	1998
54	284	Caterpillar	3406	power	127		X			Remineral / Zeppelin	D	1998
55	600	Cummins	QST30G1	emergency generator	2x127		X			DG Bank Berlin, LET	D	1998
56	220	Volvo	TWD 1210	power	91			X	X	Ochtruper Energietechnik	D	1996
57	220	Volvo	TWD 1210	power	91			X	X	Ochtruper Energietechnik	D	1996
58	220	Volvo	TWD 1210	power	91			X	X	Ochtruper Energietechnik	D	1996
59	180	Perkins	1306-9 TAG1	heat power	91			X	X	Wüstenrot	A	1997
60	240	MTU	8V 183Ta32	heat power	91			X	X	Ponts et chaussees	L	1998
61	130	MAN	2866 TE	heat power	91		X			AAN	D	1999
62	122	Cummins	6CT83	emergency generator	61		X		X	Bauamt Zermatt	CH	1996
63	78	Cummins	6 BT5,9 GI	heat power	61		X	X	X	Aerni Arisdorf Sharetech	CH	1996
64	165			power	61				X	Fa. Schnell Nr. 5	D	1997
65	73	Iveco	8061 SRI 25	power	61		X			Preisinger	A	1997
66	110	Iveco	8061 SRI 25	power	61		X			Fa. Heinkel	D	1997
67	116	Deutz	BF6M 1013E	emergency generator	61		X			FAZ Berlin	D	1999
68	84	MTU	6R 099 TA31	heat power	61		X			AAN	D	1999
69	55		4P 13.5A	heat power	61		X			AAN	D	1999
70	80	Perkins	1.006 TG A2	heat power	37		X		X	Ochtruper Energietechnik	D	1995

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No.	el. power kw	engine/vehicle	type	type of use	type of application	burner	filter	SCR	OXI	customer	country	year of order
71	80	Perkins	1.006 TG A2	heat power	37		X		X	Ochtruper Energietechnik	D	1995
72	60	Lamborghini	1000.6W	heat power	37		X		X	Basis Gemeinde	D	1995
73	50	Deutz / MWM	916	heat power	37		X	X	X	Märkisches Landbrot	D	1995
74	50	Deutz / MWM	916	heat power	37		X	X	X	Märkisches Landbrot	D	1995
75	80	Iveco	8061 SRI 25	heat power	37				X	Fa. Bosse	D	1997
76	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 1	D	1995
77	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 1	D	1995
78	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 1	D	1995
79	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 2	D	1995
80	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 3	D	1995
81	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 3	D	1995
82	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 3	D	1995
83	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 3	D	1995
84	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 3	D	1995
85	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 4	D	1996
86	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 4	D	1996
87	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 4	D	1996
88	50	Perkins	diesel (gas)	heat power	19				X	Fa. Schnell Nr. 4	D	1996
89			gas	heat power	19				X	Dreyer Bosser Kraftwerke	D	1997

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HUG ENGINEERING

no.	el. power kW	type of engine	fuel type	modul number	NOx - limit guaranteed mg/Nm3 5% O2	customer	type of use	filter	SCR	OXI	country	year of order	running hours per year
1	14,000	Wärtsilä Diesel	heavy fuel oil	400	500	Cerestar	heat power		X	X	D	1994	8,000
2	12,000	Pielstick	heavy fuel oil	360	300	Stadtwerke Västeras	heat power		X	X	S	1991	5,000
3	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Chia Hsin	heat power		X		RC	1995	8,000
4	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Chia Hsin	heat power		X		RC	1995	8,000
5	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Chia Hsin	heat power		X		RC	1995	8,000
6	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Chia Hsin	heat power		X		RC	1995	8,000
7	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Lea Lea	heat power		X		RC	1995	8,000
8	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Lea Lea	heat power		X		RC	1995	8,000
9	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Lea Lea	heat power		X		RC	1995	8,000
10	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Lea Lea	heat power		X		RC	1996	8,000
11	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Linköping	heat power		X		S	1996	8,000
12	6,400	Wärtsilä Diesel	heavy fuel oil	210	1000	Linköping	heat power		X		S	1996	8,000
13	5,710	Wärtsilä Diesel	heavy fuel oil	196	1000	TCCO	heat power		X		RC	1996	8,000
14	5,710	Wärtsilä Diesel	heavy fuel oil	196	1000	TCCO	heat power		X		RC	1996	8,000
15	6,000	MTU	diesel	176	500	Allgäuer Überlandwerke	peak shaving	X	X	X	D	1992/96	500
16	6,000	MTU	diesel	176	500	Allgäuer Überlandwerke	peak shaving		X	X	D	1992	500
17	6,000	MTU	diesel	176	500	Allgäuer Überlandwerke	peak shaving		X	X	D	1992	500
18	6,000	Pielstick/Deutz	diesel	176	1,000	WESAG Sermuth	peak shaving		X	X	D	1994	300
19	6,000	Pielstick/Deutz	diesel	176	1,000	WESAG Sermuth	peak shaving		X	X	D	1994	300
20	6,000	Pielstick/Deutz	diesel	176	1,000	WESAG Sermuth	peak shaving		X	X	D	1994	300
21	5,790	Wärtsilä Diesel	heavy fuel oil	154	2,000	Italy gas	heat power		X		I	1995	8,000
22	4,800	MBH	gas diesel	143	1000	Magdeburg	heat power		X	X	D	1995	5,000
23	4,890	MBH	gas diesel	130	500	Hammelburg	heat power		X	X	D	1993	7,000
24	4,890	MBH	gas diesel	130	500	Hammelburg	heat power		X	X	D	1993	7,000
25	5,300	MBH	gas diesel	110	500	Deersheim	heat power		X	X	D	1997	6,000
26	2,600	Sulzer	diesel	88	120	EW-Jona-Rapperswil	peak shaving		X	X	CH	1991	1,800
27	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
28	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
29	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
30	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
31	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
32	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
33	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
34	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
35	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
36	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
37	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300

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no.	el. power kW	type of engine	fuel type	modul number	NOx - limit guaranteed mg/Nm3 5% O2	customer	type of use	filter	SCR	OXI	country	year of order	running hours per year
38	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
39	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
40	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
41	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
42	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
43	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
44	3,025	Deutz	gas	88	41	Stewart and Stevenson, Chow II	heat power		X	X	USA	2000	3,300
45	2,400	Pielstick	gas diesel	80	500	Stadtwerke Ülzen	heat power		X	X	D	1993	7,000
46	2,400	Pielstick	gas diesel	80	500	Stadtwerke Ülzen	heat power		X	X	D	1993	7,000
47	2,640	MAN	heavy fuel oil	80	500	MAN B&W diesel AG	research		X	X	D	1993	2,000
48	2,400	MWM	diesel	80	1,000	Uelzen 2	heat power		X	X	D	1993	500
49	2,700	Pielstick	diesel	77	1,000	Hannover Papier	heat power		X	X	D	1997	5,000
50	2,900	Caterpillar	gas	77	100	Wattens	heat power		X	X	A	1998	5,000
51	2,900		gas	77	100	Wattens	heat power		X	X	D	1998	4,500
52	3,180	MBH	gas diesel	77	250	Harzgerode II	heat power		X	X	D	1999	6,000
53			gas diesel	77	250	Harzgerode 2	heat power		X	X	D	1999	4,000
54	2,300	Caterpillar	gas	77	270	Foley	heat power		X	X	USA	1999	16,000
55	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
56	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
57	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
58	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
59	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
60	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
61	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
62	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
63	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
64	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
65	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
66	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
67	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
68	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
69	2,926	Wärtsilä	gas	77	35	Stewart and Stevenson, Red Bluff	heat power		X	X	USA	2001	3,000
70	2,650	MBH	gas diesel	70	1,000	STW Halberstadt	heat power		X	X	D	1996	5,000
71	2,400	MBH	gas diesel	70	500	Halberstadt	heat power		X	X	D	1996	8,000
72	2,650	MBH	diesel	70	250	Harzgerode Metallwerke	heat power		X	X	D	1996	6,000
73	2,650	MBH	diesel	70	500	Mukran I	heat power		X	X	D	1996	6,000
74	2,650	MBH	diesel	70	500	Mukran II	heat power		X	X	D	1996	6,000

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no.	el. power kW	type of engine	fuel type	modul number	NOx - limit guaranteed mg/Nm3 5% O2	customer	type of use	filter	SCR	OXI	country	year of order	running hours per year
75	1,600	MWM	gas diesel	66	500	Stammheim	heat power		X	X	D	1998	7,500
76	2,100	B+W	diesel	63	1,000	Piedersdorfer	mech.power		X	X	D	1995	4,000
77	1,800	Grandi Motori	gas diesel	56	50	Thermoselect Verbania	heat power		X	X	I	1995	6,000
78	1,200	MWM	gas diesel	56	200	BTB, Steglitz, Berlin	heat power		X	X	D	1992	7,000
79	1,200	MWM	gas diesel	56	200	BTB, Steglitz, Berlin	heat power		X	X	D	1992	7,000
80	1,200	MWM	gas diesel	56	200	BTB, Steglitz, Berlin	heat power		X	X	D	1992	7,000
81	2,100	SKL	diesel	56	500	Stadtwerke Neumünster	heat power		X	X	D	1996	6,000
82	2,100		diesel	56	205	Darr / Williams NY	heat power		X	X	USA	2000	4,000
83	2,000	Sulzer	diesel	49	400	EW Schaffhausen	peak shaving		X	X	CH	1988	200
84	2,000	Sulzer	diesel	49	400	EW Schaffhausen	peak shaving		X	X	CH	1988	200
85	1,700	Sulzer	diesel	49	110	Sandoz Basel	peak shaving		X	X	CH	1989	300
86	1,500	New Sulzer	diesel	48	50	ETH Zürich	heat power		X	X	CH	1993	1,000
87	1,400	MWM	diesel	48	1,000	Uelzen 2	heat power		X	X	D	1993	500
88	1,620	MAN	gas diesel	48	500	Grimma	heat power		X	X	D	1994	8,000
89	1,620	MAN	gas diesel	48	500	Grimma	heat power		X	X	D	1994	8,000
90	1,620	MAN	gas diesel	48	500	Grimma	heat power		X	X	D	1994	8,000
91	1,800	MTU	diesel	48	500	Techn. Werke Friedrichshafen II	peak shaving		X	X	D	1994	500
92	1,800	MTU	diesel	48	500	Techn. Werke Friedrichshafen II	peak shaving		X	X	D	1994	500
93	1,960	Caterpillar	diesel	48	513	Iasia Works Taipeh	peak shaving		X	X	CN	2000	100
94	1,960	Caterpillar	diesel	48	513	Iasia Works Taipeh	peak shaving		X	X	CN	2000	100
95	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
96	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
97	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
98	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
99	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
100	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
101	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
102	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50

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103	1,330	MTU	diesel	48	2000	PSI-NET Berlin	e-power/peak shaving	X		X	D	2000	50
104	1,200	MWM	diesel	48	2000	Sony Center	e-power/peak shaving	X	X	X	D	2000	50
105	1,200	MWM	diesel	48	2000	Sony Center	e-power/peak shaving	X	X	X	D	2000	50
106	1,500	Sulzer	diesel	42	110	Sandoz Basel	peak shaving		X	X	CH	1989	400
107	1,264	Caterpillar	diesel	42	400	Techn. Werke Friedrichshafen	peak shaving	X	X	X	D	1993	300
108	1,020	Caterpillar	diesel	42	500	Velten, Berlin	heat power	X	X	X	D	1994	2,000
109	1,020	Caterpillar	diesel	42	500	Velten, Berlin	heat power	X	X	X	D	1994	2,000
110	1,020	Caterpillar	diesel	42	500	Velten, Berlin	heat power	X	X	X	D	1994	2,000
111	1,620	Caterpillar	diesel	40	500	Tuttlingen	peak shaving	X	X	X	D	1997	600
112	1,077	Jenbacher	diesel	40	50	Clinique St. Louis	peak shaving		X	X	F	2000	5,000
113		Cummins	diesel	40	1,000	Frerk Frankfurt	peak shaving		X	X	D	2001	500
114		Cummins	diesel	40	1,000	Frerk Frankfurt	peak shaving		X	X	D	2001	500
115	1,320	MWM	diesel	40	sootfilter	Bayrische Rückversicherung, Stüver	peak shaving	X			D	2001	50
116	1,200	Caterpillar	diesel	30	500	Astra Werk	peak shaving		X	X	L	1994	1,000
117	725	MTU	diesel	30	sootfilter	LIT Hamburg	peak shaving	X			D	1994	300
118	725	MTU	diesel	30	sootfilter	LIT Hamburg	peak shaving	X			D	1994	300
119	1,100	Wärtsilä Diesel	gas	30	120	KVA Weinfelden	heat power		X	X	CH	1995	5,000
120	1,700	Perkins	diesel	30	400	Obergoms	heat power		X	X	CH	1997	500
121	1,200	Deutz MWM	diesel	30	250	Uniklinik Freiburg	heat power		X	X	D	1998	3,000
122	1,186		diesel	30	600	Flughafen	heat power		X	X	L	2000	8,000
123	1,330	MTU	diesel	30	250	Clinique St. Louis	peak shaving		X	X	L	2000	1,000
124	1,000	Caterpillar	diesel	30	600	Okemo Mountain	heat power		X	X	USA	2000	8,000
125	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
126	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
127	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
128	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
129	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
130	1,330	MTU	diesel	30	2000	PSI-NET Berlin	peak shaving	X	X	X	D	2000	50
131	900	MWM	diesel	25	1,000	EW Schwandorf	heat power		X	X	D	1994	2,500
132	900	MWM	diesel	25	1,000	EW Schwandorf	heat power		X	X	D	1994	2,500
133	1,000	MTU	diesel	25	500	EW Hindelang	heat power		X	X	D	1994	1,000
134	860	Mercedes	diesel	25	120	EW Jona-Rapperswil	peak shaving		X	X	CH	1994	500
135	860	Mercedes	diesel	25	120	EW Jona-Rapperswil	peak shaving		X	X	CH	1994	500
136	1,097	Perkins	diesel	25 / F30	1000	Bauer + Sohn Holdorf	heat power	X	X	X	D	1996	6,000

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137	1,000	MTU	diesel	25	400	LUK Helmbrechts	peak shaving		X	X	D	1996	400
138	864	Dorman	diesel	25	1000	Kollmeder Presswerk Ergolding	heat power	X	X	X	D	1996	6,000
139	1,330	MTU	diesel	25	500	SES-DTF	heat power		X	X	L	1998	1,000
140	827	Jenbacher	gas	25	100	Admont	heat power		X	X	A	1998	5,000
141	827	Jenbacher	gas	25	100	Admont	heat power		X	X	A	1998	5,000
142	706	SKL	diesel	25	sootfilter	Auswärtiges Amt Berlin	emergency power	X			D	1999	100
143	706	SKL	diesel	25	sootfilter	Auswärtiges Amt Berlin	emergency power	X			D	1999	100
144	1,330	MTU	diesel	25	500	SES - DTF Gen5	heat power		X	X	L	2000	1,000
145	880		diesel	25	250	BHKW EW Heiden	heat power		X	X	CH	2000	100
146	760		diesel	25	50	Dudelange	heat power		X	X	L	2000	8,000
147	1,000	MAN		25	1,000	MANN Energie	heat power		X	X	D	2000	7,500
148	725	MTU	diesel	25	500	B.G.L.-C.R.M	peak shaving		X	X	L	1999	500
149	826	Jenbacher	gas	20	50	ETH Hönggerberg	heat power		X	X	CH	1994	4,000
150	826	Jenbacher	gas	20	50	ETH Hönggerberg	heat power		X	X	CH	1994	4,000
151	826	Jenbacher	gas	20	50	SKA Uetlihof	heat power			X	CH	1995	4,000
152	800	Jenbacher	gas	20	100	Thermoselect Verbania	heat power		X	X	I	1994	4,000
153	800	Caterpillar	diesel	20	1,000	NAM Deutag	mobil power		X	X	NL	1994	2,000
154	800	Caterpillar	diesel	20	1,000	NAM Deutag	mobil power		X	X	NL	1994	2,000
155	800	Caterpillar	diesel	20	1,000	NAM Deutag	mobil power		X	X	NL	1994	2,000
156	800	Caterpillar	diesel	20	1,000	NAM Deutag	mobil power		X	X	NL	1994	2,000
157	800	Caterpillar	diesel	20	1,000	NAM Deutag	mobil power		X	X	NL	1994	2,000
158	830	MTU	diesel	20	500	Telekom Giessen	peak shaving		X	X	D	1994	300
159	825	MWM	diesel	20	1,000	Piedersdorfer	mech. power		X	X	D	1995	3,500
160	630	MWM	gas diesel	20	50	SBG Grünenhof	heat power		X	X	CH	1995	6,000
161	685	MWM	gas diesel	20	500	Ostritz	heat power		X	X	D	1998	6,000
162	700	MTU	diesel	20	250	Ettelbrück	heat power		X		L	1998	5,000
163	800		gas	20	125	BHKW Horgen	heat power		X	X	CH	2000	4,500
164	768		diesel	20	500	Luxair	peak shaving		X	X	L	2000	1,000
165	800	Cummins	diesel	20	450	Bersano	heat power		X	X	F	1999	6,000
166	800	Cummins	diesel	20	450	Roda	heat power		X	X	F	1999	6,000
167	800	Cummins	diesel	20	450	Osva	heat power		X	X	F	1999	6,000
168	800	Cummins	diesel	20	450	Silca	heat power		X	X	F	1999	6,000
169	800	Cummins	diesel	20	450	Silca	heat power		X	X	F	1999	6,000
170	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
171	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000

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172	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
173	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
174	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
175	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
176	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
177	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien	heat power		X	X	A	1994	4,000
178	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien II	heat power		X	X	A	1996	4,000
179	681	Jenbacher	landfil gas	16	130	Deponie Rautenweg Wien II	heat power		X	X	A	1996	4,000
180	540	MTU	diesel	16	450	Leopoldina Spital	peak shaving		X	X	D	1994	500
181	540	MTU	diesel	16	450	Leopoldina Spital	peak shaving		X	X	D	1994	500
182	835	MTU	diesel	16	1,000	AEG Oldenburg	peak shaving		X	X	D	1995	130
183	681	Jenbacher	gas	16	50	SLM Winterthur SEC-Gebäude	heat power		X	X	CH	1996	4,500
184	800	Caterpillar	diesel	16	1,000	RWG Berlin	peak shaving		X	X	D	1996	3,500
185	760	MTU	diesel	16	1,000	Stadtwerke Bühl	peak shaving		X	X	D	1996	1,000
186	475	GM	diesel	16	250	TPG Geneva	heat power		X	X	CH	1997	6,000
187	690	MWM	diesel	16	250	Bernau	heat power	X	X	X	D	1997	6,000
188	630	MTU	diesel	16	300	Hospital Lohr	heat power	X	X	X	D	1997	6,000
189	490	Detriot Diesel	diesel	16	400	Hospital Baden	peak shaving		X	X	CH	1997	150
190	490	Detriot Diesel	diesel	16	400	Hospital Baden	peak shaving		X	X	CH	1997	150
191	690	Perkins	diesel	16	250	Fa. Pfeiffer	heat power		X	X	A	1997	4,000
192	500	Deutz MWM	diesel	16	100	Bundeskanzleramt	heat power		X	X	D	2000	8,000
193	576	Deutz MWM	diesel	15	sootfilter	Van Houten	heat power	X			D	1999	4,000
194	650	MTU	diesel	15	1,000	Fegert	heat power		X	X	D	1999	4,000
195	585	MAN	diesel	15	500	Decorama	peak shaving		X	X		2000	500
196	720		diesel	15	500	SES-ABC	peak shaving		X	X		1999	500
197	400		diesel	15	250	Kammgarnspinnerei Bürglen	heat power		X	X	CH	2000	3,000
198	720	MTU	diesel	15	500	Panelux	peak shaving		X	X	L	1999	500
199	585	MAN	diesel	15	1,000	Cargolux	peak shaving		X	X	L	1999	500
200	400		diesel	15	250	Bimex AG	peak shaving		X	X	CH	1999	200
201	450	MWM	diesel	15		AOK Stuttgart	e-power	X		X	D	2000	50
202	560		diesel	15	250	Spitzenlastgruppe	peak shaving		X	X	CH	1999	200
203	550	Sulzer	diesel	12	400	EW Heiden	peak shaving		X	X	CH	1992	150
204	500	MWM	landfil gas	12	70	Dimag, Liestal	heat power		X	X	CH	1993	8,000
205	470	Caterpillar	diesel	12	250	Bad Doberan	heat power		X	X	D	1993	6,000
206	470	Caterpillar	diesel	12	250	Bad Doberan	heat power		X	X	D	1993	6,000
207	470	Caterpillar	diesel	12	250	Bad Doberan	heat power		X	X	D	1993	6,000
208	400	Caterpillar	diesel	12	1,000	Heizhaus Treffurt	heat power		X	X	D	1993	5,000

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209	400	Caterpillar	diesel	12	1,000	Heizhaus Treffurt	heat power		X	X	D	1993	5,000
210	400	Caterpillar	diesel	12	1,000	Heizhaus Treffurt	heat power		X	X	D	1993	5,000
211	400	Caterpillar	diesel	12	1,000	Heizhaus Treffurt	heat power		X	X	D	1993	5,000
212	400	Caterpillar	diesel	12	1,000	Zeppelin Bünde	heat power		X	X	D	1993	3,000
213	400	Caterpillar	diesel	12	1,000	Zeppelin Bünde	heat power		X	X	D	1993	3,000
214	800	MTU	diesel	12	1,000	Energolux BG	peak shaving		X	X	L	1994	200
215	800	MTU	diesel	12	1,000	Energolux BG	peak shaving		X	X	L	1994	200
216	800	MTU	diesel	12	1,000	Energolux BG	peak shaving		X	X	L	1994	200
217	725	MTU	diesel	12	1,000	Energolux BG	peak shaving		X	X	L	1994	200
218	800	MTU	diesel	12	1,000	Energolux BG	peak shaving		X	X	L	1994	100
219	500	Cummins	diesel	12	400	OGO Oberaach	heat power		X	X	CH	1995	3,000
220	300	Deutz MWM	rapeseed oil ester	12	500	Bank 24	heat power	X	X	X	D	1996	2,500
221	300	Deutz MWM	rapeseed oil ester	12	500	Bank 24	heat power	X	X	X	D	1996	2,500
222	483	Caterpillar	diesel	12	120	SUVA Bellikon	heat power	X	X	X	CH	1996	5,000
223	550	Jenbacher	gas	12	80	Wyler Bern	heat power		X	X	CH	1998	4,000
224	525		gas	12	50	Gas Luxemburg			X	X		1999	
225		Volvo	diesel	12		Müller & Fils Pei Musee		X			L	2000	
226	450	MAN	diesel	12	1,000	Schmidt Mayen Cactus	heat power		X	X	L	2001	2,000
227	350	MAN	diesel	9	800	Stadt Lehnin	heat power		X	X	D	1992	4,500
228	350	MAN	diesel	9	800	Stadt Lehnin	heat power		X	X	D	1992	4,500
229	350	MAN	diesel	9	800	Stadt Lehnin	heat power		X	X	D	1992	4,500
230	470	Herford	diesel	9	1000	Kaiser KG, Hochstadt	heat power		X	X	D	1993	4,000
231	470	Herford	diesel	9	1000	Kaiser KG, Hochstadt	heat power		X	X	D	1993	4,000
232	330	Herford	diesel	9	1000	Kaiser KG, Hochstadt	heat power		X	X	D	1993	4,000
233	427	MWM	diesel	9	1,000	Hammelburg II	peak shaving		X	X	D	1994	200
234	416	Mercedes	diesel	9	1,000	Baatz Mercedes	heat power		X	X	L	1995	2,500
235	300	Caterpillar	diesel	9	1,000	Baatz Caterpillar	heat power		X	X	L	1995	2,500
236	250	Caterpillar	diesel	9	250	Hafner Flawil	heat power		X	X	CH	1999	4,000
237	356	Caterpillar	gas	9	250	Interlaken	heat power		X	X	CH	1999	5,000
238	420	MAN	rapeseed oil ester	9	100	Alsenblock	heat power	X	X	X	D	1999	500
239	400	Caterpillar	gas	9	80	Egghölzli	heat power		X	X	CH	1999	4,000
240	200	Perkins	diesel	9	60	Kellermann	heat power		X	X	CH	1999	4,000
241	443	Volvo	diesel	9	500	Energolux P & Ch. Petange	peak shaving		X	X	L	1999	500
242	370	MAN	diesel	9	1,000	Energolux Siemens Lux.	peak shaving		X	X	L	1999	1,000

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243	443	Volvo	diesel	9	500	Energolux P & CH. Biff	peak shaving		X	X	L	1999	500
244	443	MAN	diesel	9	450	Energolux CFL-Gare LU	peak shaving		X	X	L	2000	300
245	240	MTU	diesel	9	1,000	Energolux Pal Center	heat power		X	X	L	2000	5,000
246	240	MTU	diesel	9	500	Crailsheim	heat power		X	X	D	1999	4,000
247	443	MAN	diesel	9	500	Tunnel Burmerange	heat power		X	X	L	1999	4,000
248	443	MAN	diesel	9	500	Tunnel Burmerange	heat power		X	X	L	1999	4,000
249	300	OM	diesel	9	sootfilter	HST	heat power	X			D	2001	6,000
250	509	MTU	diesel	8	1,000	Cargocenter	peak shaving		X	X	L	1995	500
251	400	MAN	diesel	8	1,000	Polyma	mobil power		X	X	D	1993	500
252	400	MAN	diesel	8	1,000	Polyma	mobil power		X	X	D	1993	500
253	400	MAN	diesel	8	1,000	KBL	peak shaving		X	X	L	1993	500
254	400	MAN	diesel	8	1,000	Polyma	mobil power		X	X	D	1993	500
255	350	MAN	diesel	8	500	Astra Satelite EWL	peak shaving		X	X	L	1993	200
256	350	MAN	diesel	8	500	Astra Satelite EWL	peak shaving		X	X	L	1993	200
257	434	MAN	diesel	8	500	Hasslacher Linz	heat power		X	X	A	1994	3,000
258	300	MAN	diesel	8	400	Davos NAD	heat power		X	X	CH	1994	2,000
259	280	MAN	diesel	8	500	Banzkow	peak shaving		X	X	D	1994	1,000
260	440	MAN	diesel	8	1,000	Polyma	mobil power		X	X	D	1994	600
261	350	Volvo	diesel	8	1,000	Kuelbecher	peak shaving		X	X	L	1994	300
262	443	MAN	diesel	8	500	Energolux	peak shaving		X	X	L	1994	200
263	270	MAN	gas	8	80	Wärmeverbund Samen	heat power		X	X	CH	1995	6,000
264	270	MAN	gas	8	80	Wärmeverbund Samen	heat power		X	X	CH	1995	6,000
265	360	MTU	diesel	8	350	Bad Gastein	peak shaving		X	X	CH	2000	1,000
266	320	MAN	diesel	6	200	Alsa, Steinau	heat power		X	X	D	1991	2,500
267	320	MAN	diesel	6	200	Alsa, Steinau	heat power		X	X	D	1991	2,500
268	250	Caterpillar	diesel	6	500	Zeppelin Metallwerke	peak shaving		X	X	D	1992	1,000
269	140	Cummins	diesel	6	sootfilter	Hospital Heckeshorn	heat power	X			D	1997	8,000
270	140	Cummins	diesel	6	sootfilter	Hospital Heckeshorn	heat power	X			D	1997	8,000
271	140	Cummins	diesel	6	sootfilter	Hospital Heckeshorn	heat power	X			D	1997	8,000
272	140	Cummins	diesel	6	sootfilter	Hospital Heckeshorn	heat power	X			D	1997	8,000
273	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
274	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
275	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
276	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
277	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
278	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
279	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000

Reference list January 2001
stationary combustion engines

HUG ENGINEERING

no.	el. power kW	type of engine	fuel type	modul number	NOx - limit guaranteed mg/Nm3 5% O2	customer	type of use	filter	SCR	OXI	country	year of order	running hours per year
280	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
281	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
282	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
283	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
284	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
285	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
286	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
287	250		diesel	6	250	BHKW	heat power	X	X	X	CH	1998	5,000
288	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
289	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
290	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
291	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
292	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
293	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
294	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
295	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
296	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
297	250		diesel	6	250	BHKW	heat power		X	X	CH	1998	5,000
298	250	Deutz MWM	diesel	6	sootfilter	Löwenstein	heat power	X			D	1999	6,000
299	200		diesel	6		Stewo	heat power		X	X	CH	1999	8,000
300	200		diesel	6		Stewo	heat power		X	X	CH	1999	8,000
301	200		diesel	6		Stewo	heat power		X	X	CH	1999	8,000
302	200		diesel	6		Stewo	heat power		X	X	CH	1999	8,000
303	200		diesel	6		Stewo	heat power		X	X	CH	1999	8,000
304	200		diesel	6		Grawi	heat power		X	X	CH	1999	8,000
305	137	MWM	diesel	6	50	Mythenschloss	heat power			X	CH	1999	8,000
306	127	MWM	diesel	6	250	ORT-Genf	heat power		X	X	CH	2000	4,000
307	180	Perkins	diesel	6	500	Wüstenrot	heat power		X	X	A	1999	4,000
308	250	MAN	diesel	4	1,000	MAN UBS	peak shaving		X	X	L	1993	200
309	227	Volvo	diesel	4	1,000	Energolux Schmit	peak shaving		X	X	L	1993	500
310	150	MAN	diesel	4	1,000	DML Leipzig	heat power		X	X	D	1994	5,000
311	200	Caterpillar	diesel	4	1,000	Cactus Mersch	heat power		X	X	L	1995	2,000
312	70	Cummins	diesel	2	100	Aerni, Arisdorf Sharetech	heat power	X	X	X	CH	1991	1,000
313	60	Elsbett	vegetable oil	2	500	Evang. Akademie Sachsen	heat power		X	X	D	1994	6,000
314	120	SCANIA	diesel	2	1,000	Michalke	peak shaving		X	X	D	1994	300

Summary

Reference list January 2001
stationary combustion engines

HUG ENGINEERING

no.	el. power kW	type of engine	fuel type	modul number	NOx - limit guaranteed mg/Nm3 5% O2	customer	type of use	filter	SCR	OXI	country	year of order	running hours per year

total installed mech. power output of engines	**468,126**	**kW**
total module number	**13626**	**-**
total running hours per year	**1,096,230**	**h**
total mass of reduced NOx per year	**16227**	**tons**

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Company	:	**Boulden Energy Systems Inc.**			
Attn.	:	**Mr. Marc Boulden**			
Fax	:	**001 610 992 9034**	**Tel.**	:	**001 610 992 9030**
From	:	Hans J. Wagner	Depart.	:	Catalyst Systems
Tel.	:	+ 49 26 24 13 338	Date	:	February 14, 2001

Total page(s) incl. front page: 11

Steuler SCR Catalyst Systems for Exodus
(14) Catalyst Systems for Caterpillar Diesel 3516-B-140 L/E

With reference to your recent inquiry, enclosed is our propsal for (14) units of our SCR Catalyst NOx reduction system for service on the (14) Caterpillar Diesel 3516-B low emission engines operating at 2 MW each. The basis of this proposal is that the fourteen will be identical, and that the order shall be placed for a minimum of seven (7) SCR systems at a time to be fabricated and supplied in a single shipment.

Let me take this opportunity to summarize main features and benefits of a Steuler Catalyst System compared to competition :

- Lower investment and operating cost
- Lower pressure drop across catalyst bed
- Longer guarantee and warranty on catalyst life time
- Compact system design, easily accessible components
- PC based data acquisition system and continous process visualisation. Built-in modem allows unlimited system access via phone line to support customer in operation, service / maintenance and trouble shooting remotely.
- Ongoing customer support : Long term full service and maintenance contracts

Our proposal is as follows :

(14) SCR Catalytic exhaust gas treatment systems to be operated behind (14) CATERPILLAR Diesel 3516-B-140 L/E

Operating conditions (as per your inquiry dated January 24, 2001)

engine	:	(14) x Caterpillar Diesel 3516-B-140 L/E
fuel	:	Light Diesel fuel
energy input	:	100 % = 20,073,000 BTU/Hour.
load, [%]	:	100 % = 2876 BHP / 2000 kW
exhaust flow rate, wet	:	27,260 Lbs/Hour
exhaust flow rate, wet	:	17,051 ACFM / 6,500 SCFM
exhaust gas temperature, [°C]	:	approx. 700 to 965 °F
required temperature window across catalyst system	:	608 – 968 ° F
lambda	:	1.47

Emission inlet concentrations

NO_X as NO_2, dry, max.	:	6.56 g/BHP-hr / 1,830 mg/Nm^3 900 ppmvd @ 9.85% O2.
CO, dry, max.	:	N/A
C_2H_4, dry	:	N/A
NMHC, wet	:	N/A
SO_2, dry	:	N/A
CO_2, dry	:	N/A

Rest as per Caterpillar engine data sheet

Outlet concentrations behind SCR Catalyst System

NOx, max.	:	96% Reduction – to 0.26 G/BHP/Hr.
Carbon Monoxide (CO), max.	:	no requirements.
Hydrocarbons (HC), max.	:	no requirements.

Consumption of chemicals (per system)

40 % Urea-solution	:	70.4 Lbs/Hr / 9.3 GPH

Guaranteed catalyst life time

SCR-catalyst	:	20,000 operating hours, max. 3 years

Pressure drop across catalyst system

Incl. Housing (flange to flange)	:	approx. 7.5 mbar / 3 inch WC

Overview

Scope of supply

(14) SCR Catalyst Systems for Caterpillar Diesel 3516-B-140 L/E engines, with each system consisting of :

Item 1) (1) Reactor housing for vertical / horizontal gas flow, loaded with SCR catalyst material

Item 2) (1) Urea supply, metering and injection unit

Item 3) 1) Electrical equipment and urea injection control system utilizing a 4-20 mA engine load signal and feedback from a Continuous Emissions Monitoring System (CEMS), pressure drop indication, PC, process visualization via an S-VGA monitor and telemetric system with modem.

Item 4) Engineering and Documentation

Item 5) System check-out and start-up

Deliveries by customer or third party

- telephone lines to our control panels
- all not specified equipment and components
- not specified steel constructions and steel works
- assembly, field cabling, wiring and piping within our scope of supply
- exhaust gas ducting incl. all necesarry accessoires
- thermal insulation

Equipment specification

(For each SCR exhaust gas treatment system)

Item 1) (1) Reactor housing for horizontal or vertical gas flow, loaded with SCR catalysts material

a) Reactor housing

consisting of the gas tide reactor housing; made of regular carbon steel and high temperature construction steel; including all necessary precautions to hold 3 + 1 layer SCR-catalyst material in place; gas inlet and outlet transissions, one hinged excess door for loading and unloading of catalyst modules. The reactor housing will be delivered without support and without thermal insulation.

dimension of the reactor housing without thermal insulation

height / length approx.	:	approx. 3,500 mm / 138 inches
cross section	:	approx. 1,500 x 1,500 mm 59.0 x 59.0 inches
reactor material	:	boiler plate
weight without catalyst material	:	approx. 1,200 kg / 2,645 lb
weight incl. Catalyst material	:	approx. 2,300 kg / 5,070 lb
dimension inlet/outlet flange connections	:	to be agreed upon

b) SCR-catalyst

consisting of (3) layers SCR-catalysts and (1) empty spare layer

type	:	honeycomb body

dimensions per module incl. stainless steel wire mesh

length	:	305 mm
width	:	157 mm
height	:	157 mm
Module volume	:	243 modules
arrangement	:	in 3 layers, 9 x 9 per layer
catalyst surface	:	880 m^2/m^3

Item 2) (1) Urea supply, metering and injection system

consisting of:

a) (1) metering and control unit

incl. fine metering pump with speedcontrolled drive

urea volume flow	:	approx 10 – 50 Litres

b) (1) injection lance

with a special 2-phase nozzle with high temperature protection, to be mounted into the exhaust gas duct upstream of the reactor housing.

material	:	stainless steel

c) (1) set adapter and fittings

d) (1) fine filter

to precipitate suspended matters from reducing agent

mesh width : < 80 microns

e) (1) metering pipe

between urea control panel (metering pump) and injection lance.

length : 10 m

f) (1) compressor station incl. accessoires

to supply the 2-phase nozzle of the injection lance with compressed air.

Item 3) (1) Electrical equipment and urea control system

Following engine load signal to determine required amount of reducing agent, personal computer and process visualisation; consisting of the following main components

(1) automatic urea metering and control unit

to inject urea in accordance to engine load (feed forward loop) and continuous NOx measurement (CEMS feedback loop). Typical load signal (4-20 mA) from the diesel engine will be supplied by customer according to our specification. The exact amount of urea to be injected will be fine tuned during system commissioning.

(2) temperature probes, PT 100

to control the operating temperature and the exothermal reaction across the oxydation catalyst with stop-function for the engine and to release the urea injection upon exceding the required min. operating temperature at the catalyst.

(1) completely wired switch cabinet unit

acc. to VDE standards with main switch and starting possibilities

dimensions of the switch cabinet

depth approx.	:	24 inches
width approx.	:	24 inches
height approx.	:	84 inches

All of our electrical equipment is in accordance with the latest EN-VDE regulations.

Item 4) Engineering and documentation

including all necessary shop drawings, layout plans, block diagramms, process flowsheets, P&I diagrams and documentation of the whole catalyst system based on our standards and specifications

Item 5) System check-out and start-up

of the catalyst system, items 1 - 4 at site,
typically consisting of the following works:

Complete system check-out, assembly acceptance (assembly and cabling by customer) and start-up of the catalyst systems by our engineer as well as operator training.

Commercial Terms

Quotation

Our prices are net, excl. VAT, shipped to USA East Coast Port, customs cleared and duty paid. Transportation to site is not included !

Payment

40 % after receipt of order
40 % after delivery of hardware components
20 % after start-up
payable 4 weeks after tendering of account, net.

Validity of price

Our prices are budget prices. Optional prices to be understood as additional prices.

Prices for long term service and maintenance can be quoted under separate cover.

Delivery period

Approx. (14) - (16) weeks after receipt of order and clarification of all technical details.

Guarantee

1. General

Guarantee is assumed within the scope of our "Conditions of Contract and Guarantee for Protection against Acids and Process Equipment" which constitute an integral part of our quotation.

Any subsequent complaint caused by non-observance of our "Conditions of Contract and Guarantee for Protection against Acids and Process Equipment" is rejected by us. Any further claims, particularly those for compensation are excluded, unless expressly concede under the General Terms of Business.

2. Duration of Guarantee

For all parts excluding catalyst and wearing parts, 1 year after acceptance, max. 30 months after shipment which ever occures first.
Additional necessary equipment which can be different locally must be considered by customer and is not contained in the quotation. (E.g. acid collecting pits, safety precautions, possible noise control measures, possible further treatment of the waste water, possible special stack etc.)

Performances by customer

The customer is responsible for the following in order to make a fast accceptance of assembly and start-up possible:

The unloading of the arriving material and its transport to jobsite.

Making available a dry and safe storage place for material and tools.

Making available a proper washing-, dress and social room near by the jobsite for our personnel during the time of work.

Making available of light, power current, clean water, heating if necessary etc. with the connection at site.

Erection of necessary foundations for reactor, control panel, pumps and tank acc. to our instruction.

Complete assembly of our scope of supply incl. field cabling between panels and consumers.

Execution of possibly necessary masons-, concrete- and mortising works, if necessary.

Obtaining of official permits to build and operate the system.

Flaps, stack, condenser and silencer, bypass, pre-cooler if required.

Thermal insulation.

All not specified and unknown items.

In case that assembly is carried out by customer we only assume the function guarantee if the assembly is accepted by us and the system is commissioned by us.

We hope that our quotation meets your expectation and would be pleased to receive your order.

Should you have questions regarding the quotation, please don't hesitate to contact us. We will be very pleased to work with Boulden Energy Inc. on this project.

Best regards,

STEULER ANLAGENBAU GmbH & Co.KG

Hans J. Wagner
Senior Manager Catalyst Systems

Angebote / Bboulden002.doc

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Catalytic Systems Division

SCR Systems and Catalyst

Johnson Matthey offers the unique combination of significant technical expertise and experience in SCR systems and catalyst, with over 15 years of experience controlling NOx from gas turbines, boilers and diesel engines throughout the United States.

Urea SCR (Click here to download brochure)

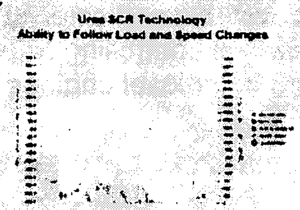
J ohnson Matthey's Urea SCR system provides 70% to 90+% NOx reduction for applications including:

- All new or existing lean-burning engines
- Power generation
- Cogeneration
- Pumping
- Natural gas engines for gas compression

Advantages

T he Johnson Matthey Urea SCR system offers several advantages to other reduction technologies:

- Uses safe, non-hazardous urea - a common component of fertilizer
- The only patented*, flow-through, non-plugging injector system, eliminating the need for compressed air
- Requires no engine modifications, allowing the engine to operate at maximum fuel economy
- Based on engine parameters eliminating expensive continuous emissions monitoring devices
- Compact controls, small footprint, easily retrofitted to an existing engine
- System has built-in fail safes & alarms
- Robust metallic catalyst substrate
- Can be used for generating NOx credits



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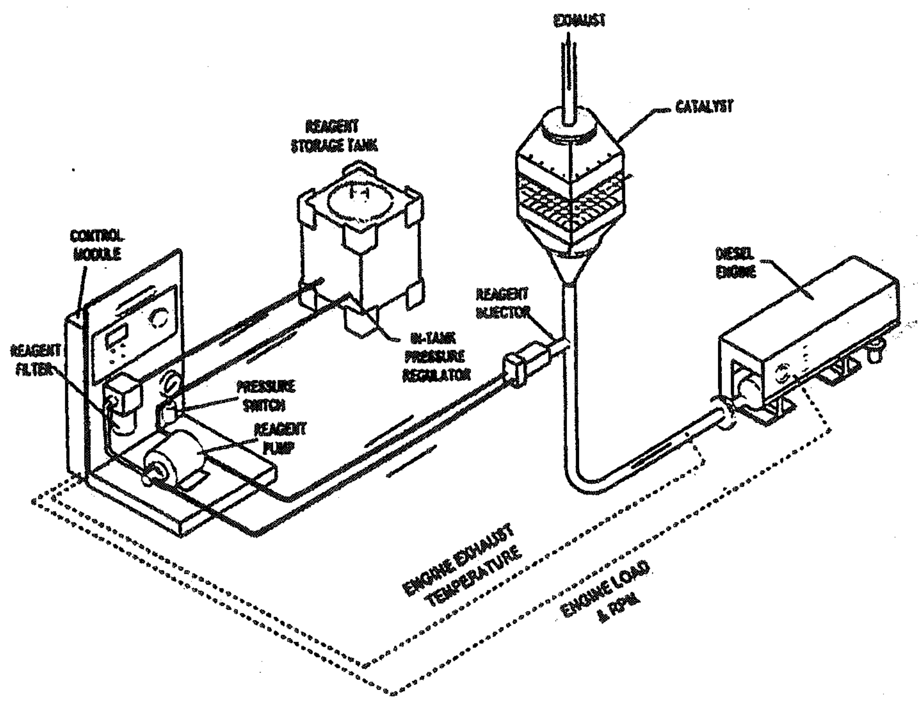
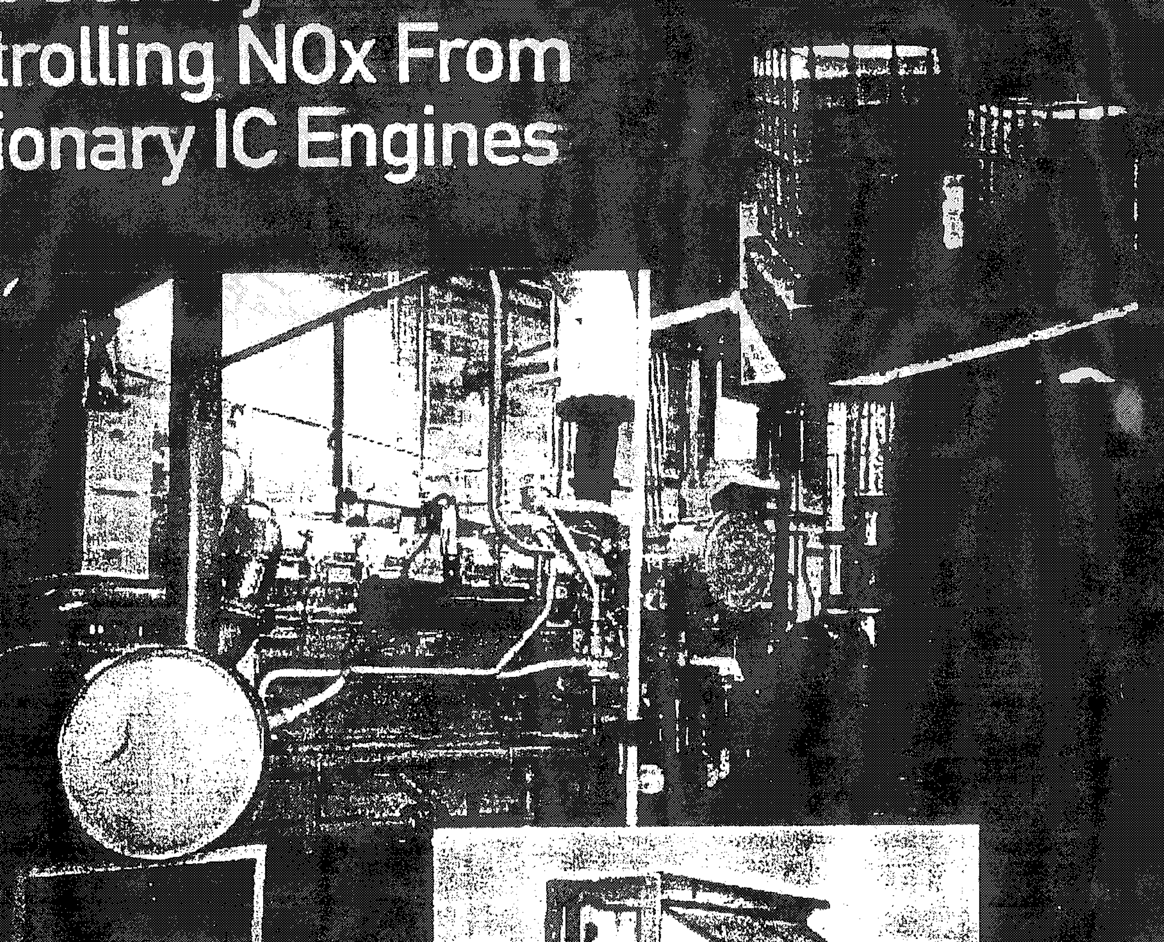
Research and Development
Due to increasingly stringent regulations for NOx, commercial interest in Urea SCR technology continues to grow. Johnson Matthey has ongoing research and development initiatives in a number of diesel and natural gas engine projects, ranging from 200 to 9,000 hp.

*Aris 2000 patented by Clean Diesel Technologies Inc. and licensed to RJM Corporation for stationary engine applications

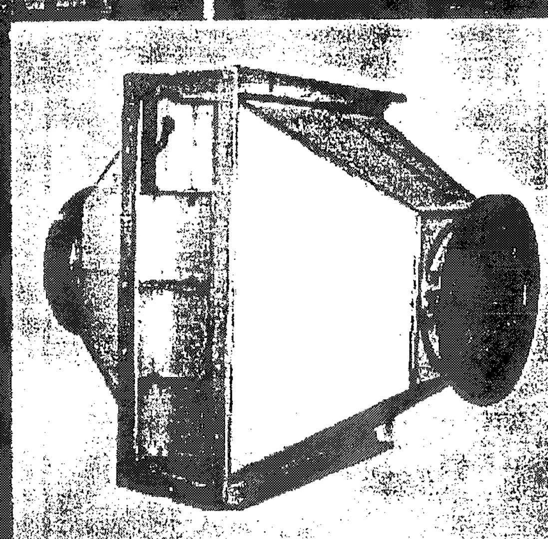
Catalytic Systems Division



The Johnson Matthey Urea SCR System For Controlling NOx From Stationary IC Engines



Urea Storage Tanks



Catalytic Converter

Urea Injector and Controls

JM

Johnson Matthey

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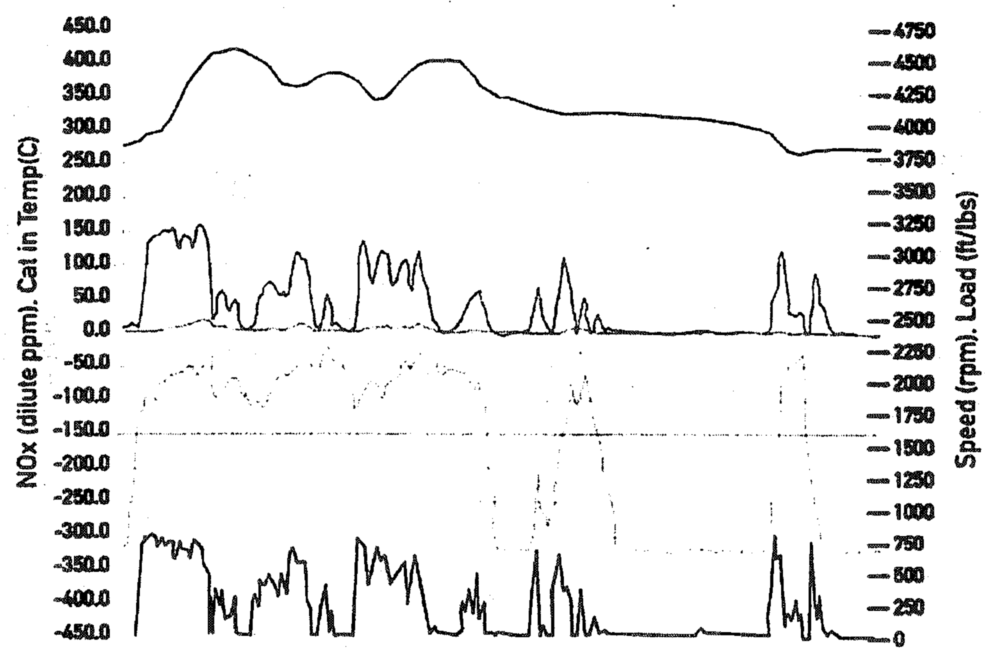
Urea SCR Technology
Ability to Follow Load and Speed Changes

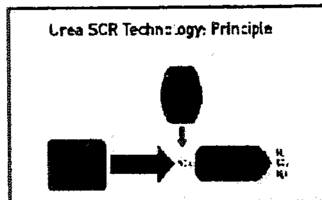


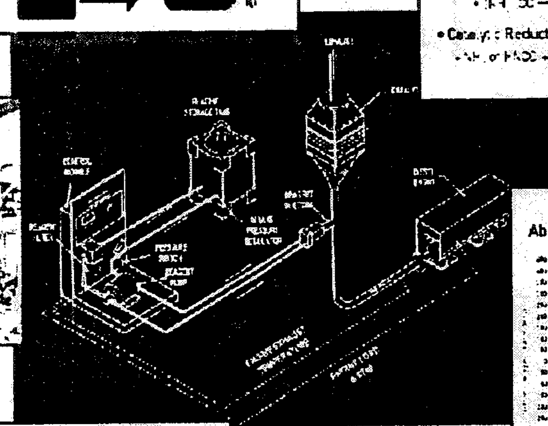
Johnson Matthey—the leader in SCR technology

Johnson Matthey offers the unique combination of significant technical expertise and experience in SCR applications. Johnson Matthey is a leader in SCR catalyst technology with over 15 years of experience controlling NOx from gas turbines, boilers and diesel engines throughout the U.S., all designed and engineered by the company's Environmental Products group. Now Johnson Matthey introduces Urea SCR for stationary IC engines.

Because Urea SCR technology provides high reduction of NOx from engines that are presently uncontrolled, it can have a vast impact in applications for all new or existing lean-burning engines, power generation, cogeneration, pumping, and natural gas engines for gas compression.

The basic principle of SCR is the reduction of NOx to nitrogen and water by the reaction of NOx and a reagent, such as ammonia or urea. The mechanical operation of an SCR system is quite simple. It consists of a reactor chamber with catalyst modules plus a reagent handling and injection system. Reagent is injected into the exhaust gas upstream of the catalyst.

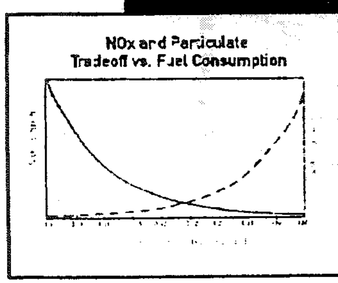


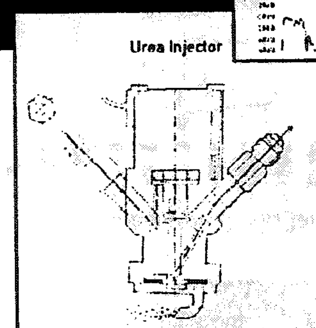


The Importance of Reducing NOx Emissions

There are a number of reasons why the reduction of NOx emissions is critical. Emissions of nitrogen oxides (NOx) cause serious health effects, ranging from bronchitis to altered immune system function. NOx also contributes significantly to the formation of acid rain and ground level ozone pollution. Federal and state regulations require control of NOx emissions to minimize their direct effect on human health and the environment. In particular, NOx reductions are needed to meet Federal ozone non-attainment standards.

There are several NOx control technology options available for stationary IC engines. These include SCR (Selective Catalytic Reduction), injection timing retard (ITR), water injection, emulsions, turbocharging, intake air cooling, air/fuel mixing, high-injection pressure and rate shaping, exhaust gas recirculation (EGR) and turbocompounding. Of these technologies, the most efficient method for high conversion of NOx is SCR.





Urea SCR: A New Generation of Cost-Effective Control Technology

In current product development and testing stage, Urea SCR is proving to reduce NOx and achieve significant fuel savings in heavy-duty diesel truck applications. These positive results achieved in mobile applications are helping Johnson Matthey to develop a new generation of less expensive, yet highly effective, SCR systems for stationary applications. In essence, the research and testing done for on-road trucks have generated benefits of greater availability, improved reliability and cost-savings for stationary engines. Urea SCR is innovative technology that lowers costs, reduces risk and delivers performance...all factors that make it very attractive. Additional advantages that Urea SCR offers over alternate technologies are that it:

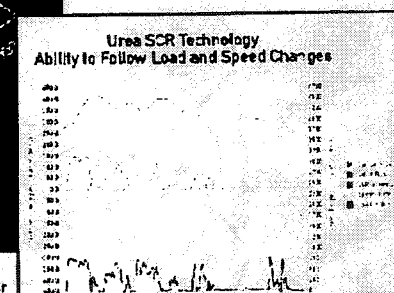
- Allows the engine to operate at maximum fuel economy
- Requires no modification of the engine
- Requires lower maintenance
- Delivers extremely high NOx reductions
- Can be used for generating NOx credits
- Is safe and non-hazardous

Additionally, urea is a dry, non-hazardous common component of fertilizer. It's readily available, and dissolves easily in water to form a 32.5% solution which is optimum for concentration and protection from freezing. By using economical, on-site storage tanks or portable totes, the urea solution is ideal for use as the reagent for SCR systems.

In the Urea SCR process, urea reagent is injected into the exhaust stream in front of an SCR catalyst to produce ammonia in the exhaust which then reacts selectively with NOx to form nitrogen and water. Approximately two tons of 32.5% urea solution are required for each ton of NOx removed. NOx reductions of 70 to 90% can be achieved at typical exhaust temperatures of 300° to 425° C.

Urea SCR Chemistry

- Decomposition
  - Urea Hydrolysis
  - Urea Pyrolysis
- Catalytic Reduction of NOx



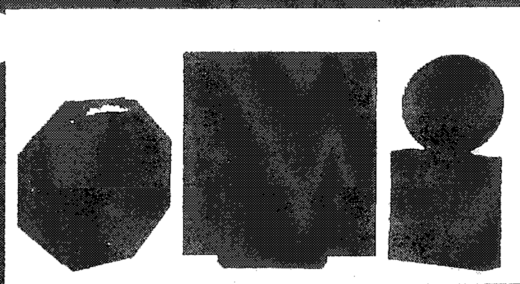
Continuous Flow Urea Injection System

The key advantage of the Johnson Matthey Urea Injection system is that it has a continuous flow mechanism. Unlike competitive systems, the injection system is unique because it eliminates the need for compressed air, thereby reducing system complexity. This reduces the additional costs associated with compressors, increased loads and two-pump systems for fluid and air. Plus, the system has built-in fail safes. The system will not allow the urea tank to run dry. Injection automatically stops when urea reaches a minimum level. Also, the pump has a pressure sensor to monitor proper operation and activates an alarm in the case of a problem.

Some of the unique benefits of the Johnson Matthey system include:

- A patented*, flow-through (no air), non-plugging injector design originally developed for rugged on-the-road, long-haul truck applications
- The urea control system is driven by external AC power and requires no air or hydraulic supply
- The urea control system is based on engine parameters (engine map) and does not require expensive continuous emissions monitoring
- Compact controls, small footprint, easily retrofitted to an existing engine

* Patented by Clean Diesel Technologies Inc. and licensed to RJM Corporation for stationary engine applications



SCR Catalyst Performance

Johnson Matthey Urea SCR systems have proven effective in reducing NOx emissions by more than 90% on diesel engines and natural gas engines. Plus our comprehensive line of SCR catalysts offer the following advantages:

- SCR catalyst technology leadership for over 15 years
- Metal monolith substrate for maximum performance and durability
- Easy to install and maintain
- Designed with minimal back pressure for fuel savings, and reduce engine wear
- Available in a wide range of standard sizes and shapes as well as custom sizes

The Future of Urea SCR

Due to increasingly stringent regulations for NOx, commercial interest in Urea SCR technology continues to grow. Johnson Matthey has ongoing research and development initiatives in a number of diesel and natural gas engine projects, ranging from 200 to 9,000 hp. Because of its cost-effectiveness, non-hazardous nature and viability, the future for this new generation of Urea SCR applications looks very bright.

Now—more than ever—NOx needs to be reduced. Johnson Matthey has the experience and technology to provide you with the most advanced Urea SCR solutions. Call Johnson Matthey today at 800-793-6724 to discover the future of Urea SCR.

JM
Johnson Matthey

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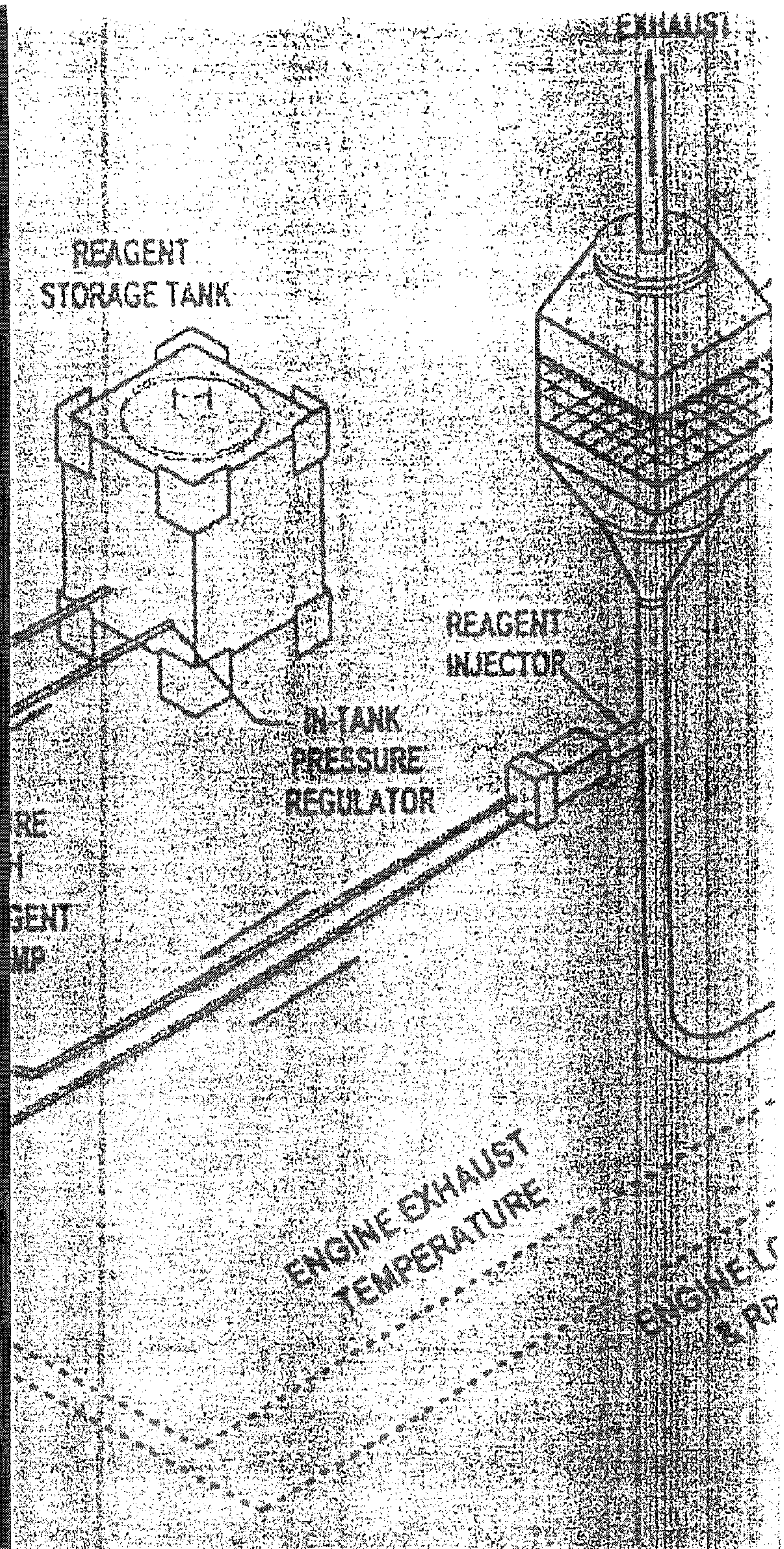

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To find out more about how Engelhard ingenuity can help you meet today's — and tomorrow's — environmental and business challenges, please contact us at:

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ENGELHARD
Change the nature of things.

ENGELHARD

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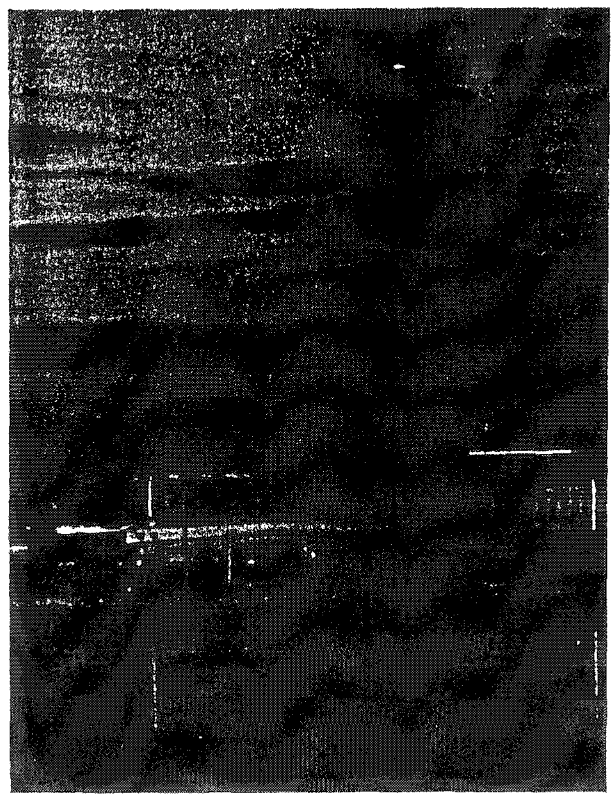
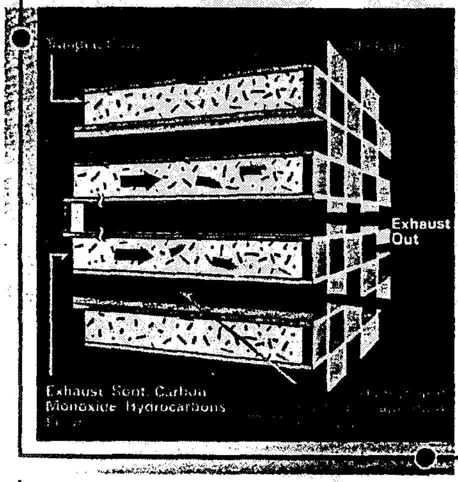
Engelhard Ingenuity Meets Today's Challenges Around the World

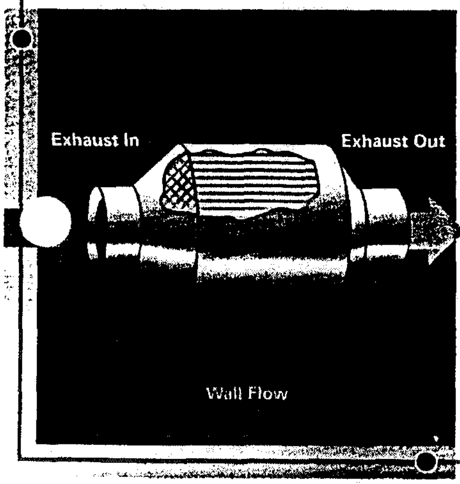
Environmental protection will continue to grow in importance in years to come. The operations that succeed in the future will be those that comply with increasingly stringent emissions control standards while maintaining a competitive advantage. Engelhard ingenuity is focused on helping companies worldwide do just that.

Engelhard has long been a leader in catalyst technology, known for creating ingenious solutions to problems big and small. We offer exceptional emissions control products and systems for power plants, cars, buses, trucks, trains, airplanes, lawn mowers and forklift trucks. Our manufacturing, research and sales facilities span the globe.

In recognition of our dedication to delivering quality products and services, we have been awarded both ISO 9001 and QS 9000 certifications.







TWX™ three-way catalyst
For NOx, carbon monoxide and hydrocarbon abatement in rich burn natural gas engines. This technology is part of our non-selective catalytic reduction (NSCR) system.

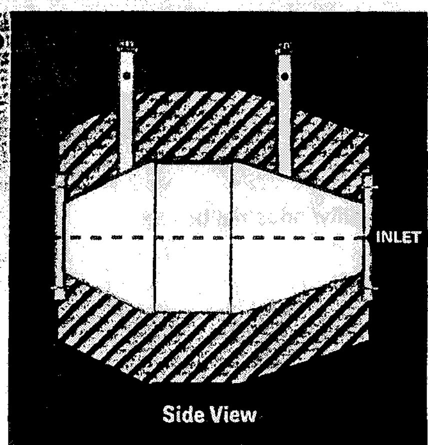
Application
The TWX™ three-way catalyst is specifically designed for a four-cycle, spark-ignited, rich-burn natural gas engine equipped with air/fuel ratio control.

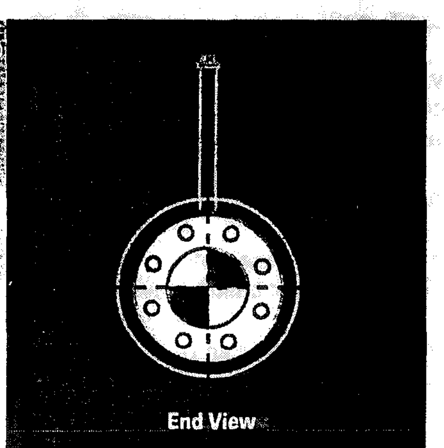
Performance
Performance can be predicted based upon the length of time that the exhaust gas is in contact with the catalyst surface.

The Engelhard solution for controlling particulate (soot)

Engelhard's DPX™ Particulate Traps
Engelhard's DPX™ catalyzed diesel particulate traps are ideal for controlling particulate matter. When exhaust gases are 375°C (700°F) for at least 25% of the time, particulate burns passively when contacting the catalyzed ceramic filter surface. This diesel particulate is then converted to carbon dioxide.

- 90% effective against carbonaceous particulate matter
- Up to 98% effective against soluble organic fractions
- Also helps reduce CO and HC





Standard Round

Oxidation

Catalysts for

Power Generation

Easy installation
All Engelhard catalysts for stationary engines are simple in design, for economical construction and ease of installation.

Long product life
Our stationary engine catalysts are constructed of stainless steel to provide reliable service for many years to come.

High conversion efficiency
Engelhard catalysts are highly effective in CO, NOx, HC and PM reduction. In addition, they are characterized by low pressure drop. And the convenience of removable test cartridges makes your job easier.

Choose the products that meet your emissions control needs.

GEN™ diesel oxidation catalyst
For hydrocarbon and carbon monoxide abatement with secondary particulate reduction

Application
The Engelhard GEN range is specifically designed for abatement of carbon monoxide and hydrocarbons from large stationary generator sets. The GEN range may also be applied to mobile engines where the exhaust gas flow rate requires a large catalyst volume. The GEN range may be applied to either standby or continuously running engines.

Performance
The catalyst functions through the process of oxidation, converting CO to less harmful CO_2 and HC to CO_2 and water (H_2O). Conversion of the gaseous compounds is dependent upon the temperature of the exhaust gas stream and the flow rate.

COCat™ oxidation catalyst
For superior carbon monoxide abatement from natural gas and LPG engines.

Application
The Engelhard COCat range is specifically designed for abatement of carbon from large stationary generator sets. The COCat range may also be applied to mobile engines where the exhaust gas flow rate requires a large catalyst volume. The COCat range may be applied to either standby or continuously running engines.

Performance
The catalyst functions through the process of oxidation, converting CO to less harmful CO_2. Conversion of the gaseous compounds is dependent upon the temperature of the exhaust gas stream and the flow rate.

Today's clean air standards demand ingenious emissions control solutions— from Engelhard.

Engelhard has the right SCR catalysts for the job.

VNX™ catalysts

- Ideal for reciprocating engines, gas turbines, utility/industrial boilers and chemical process applications
- Most effective at 550°F to 800°F (288°C to 427°C)
- Highly active vanadia/titania catalytic coatings
- Ceramic structures in composite honeycomb configurations

ZNX™ catalysts

- A unique technology for higher temperature applications
- Most effective at 675°F to 1075°F (357°C to 580°C)
- Highly active zeolitic catalytic coatings
- Ceramic structures in composite honeycomb configurations

Add up the benefits of SCR catalysts

- Up to 99% NOx removal enables regulatory compliance
- Compact, modular reactor designs mean easy installation with any engine.
- Utilizes either urea or ammonia reductant to accommodate to existing infrastructure
- Proven design assures reliable operation and low maintenance
- Designed for reciprocating engines, to produce less soot buildup, low ammonia slip and longer catalyst life
- Engelhard's integrated design incorporates particulate traps and oxidation catalyst, which means single accountability with a unified approach to exhaust stream

Engelhard offers proven CO and HC emissions control catalysts.

Our products reduce emissions from most types of stationary engines, including:

- Diesel and natural gas generators
- Diesel-powered heavy machinery
- Gas pumping stations

We can provide products for engines powered by most fuels, including Number 2 Diesel, LPG, natural gas and dual fuel.

Engelhard Catalysts and Systems

For Environmental Compliance and Competitive Advantage

You face a challenge.

Today, the most challenging issue for operators of standby power generators is how to meet emissions standards without sacrificing the business advantages of generating their own power. Engelhard ingenuity can help.

Engelhard has the solution.

Engelhard is an acknowledged leader in [illegible] emissions control technology. We offer catalyst solutions that destroy the pollution produced by power generation equipment, whether fueled by natural gas or diesel. Our innovative catalysts and systems offer superior conversion, long catalyst life, ease and flexibility, enabling you to comply with environmental standards while [illegible] retaining your competitive advantage.

NOx regulatory compliance is easy with Engelhard SCR technology.

Today, facilities using diesel and natural gas engines for power generation are facing strict regulations that demand NOx reductions of more than 80%. That's no problem for facilities using Engelhard's selective catalytic reduction (SCR) technology. In the last decade, this technology has helped reduce 30,000 tons of NOx annually. Engelhard SCR technology enables you to remove up to 99% of NOx – significantly more than environmental regulations require.

Easy, safe, cost effective.

Engelhard's SCR catalyst system work[illegible] exhaust gases as they pass through SCR [illegible] honeycombs to promote NO and NO[illegible] with added urea to produce nitrogen [illegible] We use urea as the reductant, although ammonia injection is available upon request. [illegible] great advantages over conventional ammonia systems because of its easy transport[illegible] safer storage and handling, and lower [illegible]

An added bonus: CO, HC, PM reduction.

Beyond NOx, Engelhard's SCR [illegible] can destroy CO (carbon monoxide) [illegible] (hydrocarbons) with oxidation cata[illegible] integrated particulate trap captures [illegible] (particulate matter) from the exhaust [illegible] and burns it away.

Sized to fit your requirements.

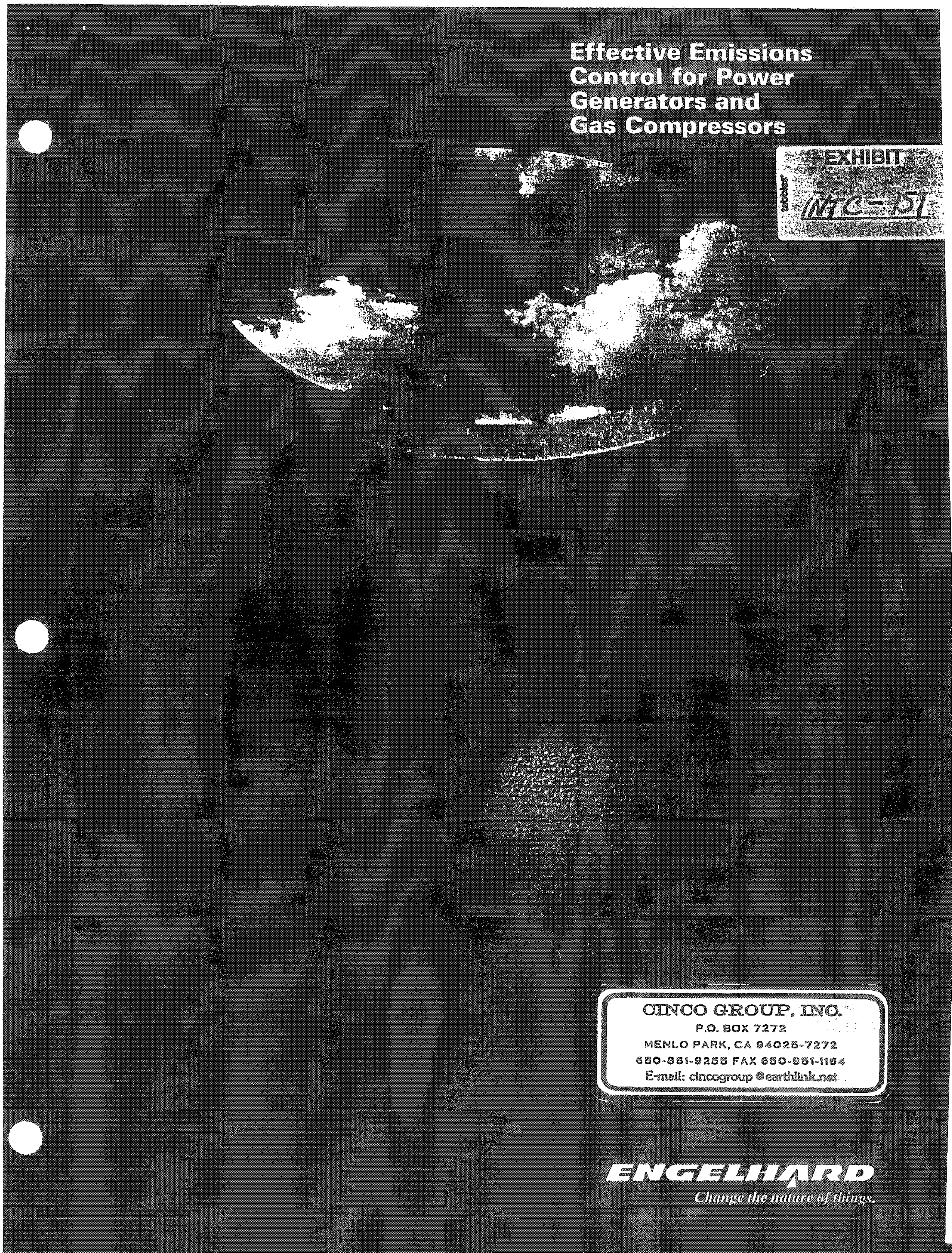
Engelhard's SCR catalyst system is available in compact, medium and large reactor sizes to cover performance ranges from [illegible] to 20 MW. Within these sizes, we [illegible] catalyst modules precisely based on your exhaust gas flow. This design offers the quality and [illegible] benefits of fabrication repeatability [illegible] delivering the right catalyst size for your volume. And our engineers work with your maintenance staff to coordinate installation [illegible]

Engelhard Emissions Control Technologies for Power Generation

APPLICATION	HC	CO	NOx	PM	TECHNOLOGY
Lean burn natural gas			•		VNX™ Catalysts/SCR Systems
		•			COCat™ Catalyst
			•		ZNX™ Catalysts/SCR Systems
Rich burn natural gas	•	•	•		TWX™ Catalyst/NSCR
Diesel			•		ZNX™ Catalysts/SCR Systems
	•	•		•	GEN™ Catalyst
	•	•		•	DPX™ Particulate Trap

Effective Emissions Control for Power Generators and Gas Compressors

EXHIBIT
INTC-151



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E-mail: cincogroup@earthlink.net

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INNOVATIVE EMISSIONS CONTROL TECHNOLOGY

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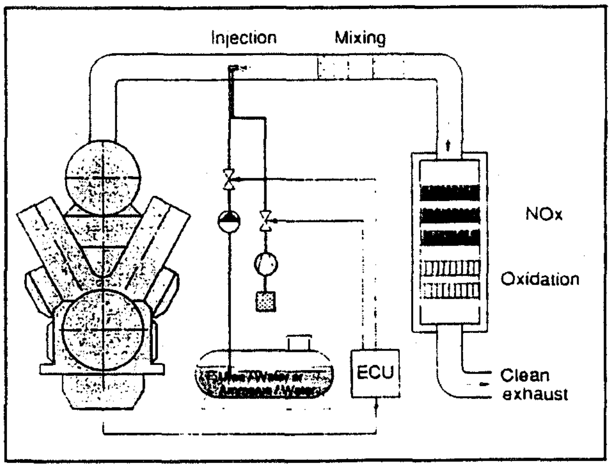
Heavy Duty Power Systems
Supplier of Kaparta SCR Systems



Features:	Benefits:
Up to 99.9% NO_x removal	Enables regulatory compliance
Compact, modular reactor designs	Easy installation with any engine
Utilizes urea or ammonia reductant	Accommodates existing infrastructure
Proven design (with over 400 systems in operation)	Reliable operation, low maintenance
Catalyst designed for reciprocating engines	Reduced soot buildup, low ammonia slip, longer catalyst life
Integrated design incorporating soot filters and oxidation catalyst	Single accountability with unified approach to exhaust stream

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'he Soot Filter

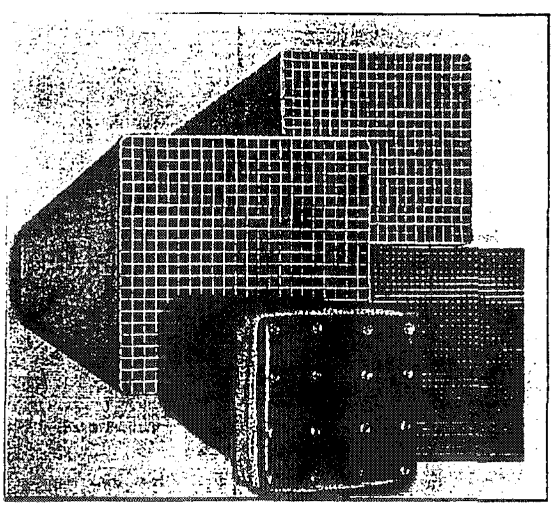
An integrated fibrous soot filter, captures the fine particulates from the exhaust gas and burns them away on the catalyst-impregnated surface at system temperatures higher than 825° F.

Reactor Design Features Three Sizes with Modular Catalysts

Compact, medium, and large reactor sizes have been developed to cover the performance ranges from 100 kW to 20 MW. Within these sizes, the catalyst modules are precisely sized based on exhaust gas flow. This design offers the quality and cost benefits of fabrication repeatability, while providing the appropriate catalyst volume sizing.

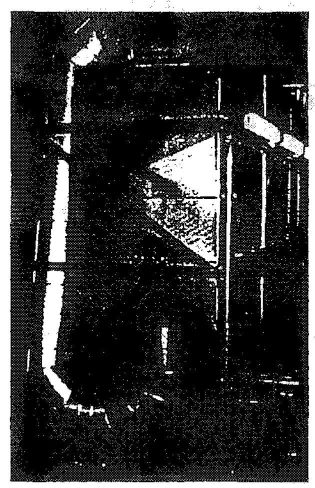
Catalysts

Ceramic honeycomb substrates with varying cell densities are provided based on flow requirements. Highly active vanadia/titania catalysts are used in the systems. Vanadia/titania catalysts have been 'sed successfully throughout the world in SCR pplications. Zeolite catalysts are available for higher temperature applications greater than 960° F.



Design and Assembly

Electrical control designs and documentation are prepared and carefully tested before delivery through a pilot simulation plant. Easy-to-handle units)f the honeycombs and filter elements in convenient sizes are tightly packed into the reactor chambers. These elements can be exchanged at any time via the reactor opening. The reactor uses robust stainless steel construction to insure structural integrity and an aluminum-clad insulation for low outer-wall temperatures. Fabrication is completed under the supervision of both Engelhard and Kaparta engineers.

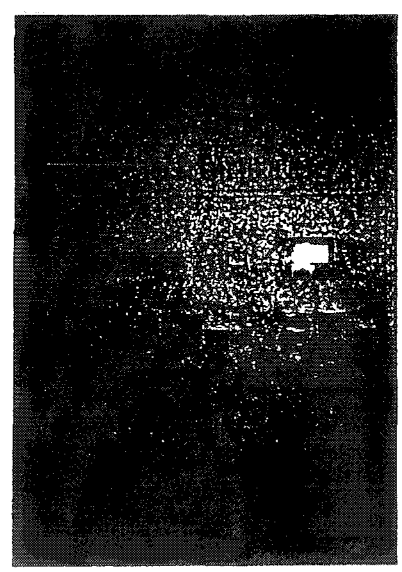


Installation, Start-up, and Service/spare parts

Installation is coordinated by our project engineers with the local site. A specialized start-up team will commission the system and provide operator training for the maintenance staff. An extensive stock of spare parts is maintained to meet rapid customer requirements.

Trouble-free Operation

These field-proven designs maintain excellent reliability. Modular controls and urea injection components require minimal operator input.



Engine applications:	Diesel and natural gas
Size range:	100 kW to 20 MW

Extensive experience with diesel and natural gas engines manufactured by leading OEMs.

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INNOVATIVE EMISSIONS CONTROL TECHNOLOGY

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Engelhard and Kaparta—Leaders in SCR Technology for NO_x Control

Engelhard, the leader in clean air technology and inventor of selective catalytic reduction (SCR) technology, has brought the Swiss-designed, Kaparta SCR system to the U.S. and Asia. The system has been proven in over 400 installations throughout Europe and Asia since 1986, with over 30,000 tons of NOx reduced annually.

The Problem

Nitrogen oxides (NO and NO_2) are reduced by the SCR process. NO is a colorless gas which oxidizes in air to NO_2, which is a red-brown gas with a sharp, pungent smell. When combined with hydrocarbons (HC) and sunlight, NO_2 forms ground level ozone, also known as smog.

Emission Control Requirements

Increasingly, stationary diesel and natural gas engine customers are being faced with strict regulations that demand confirmed NO_x reductions of over 80%. As local requirements for NO_x and HC tighten to reduce ozone, (particularly in California and the Northeast) Engelhard and Kaparta are ready to assist you with regulatory compliance.

The Fundamentals of the SCR System

Nitrogen oxides are reduced by the SCR process. The exhaust gas passes through SCR catalyst honeycombs to promote the reduction of NO and NO_2 with added urea to produce nitrogen and water. The basic chemical reactions in this process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_20$$
$$2NO_2 + 3N_2 + O_2 \rightarrow 3N_2 + 6H_20$$

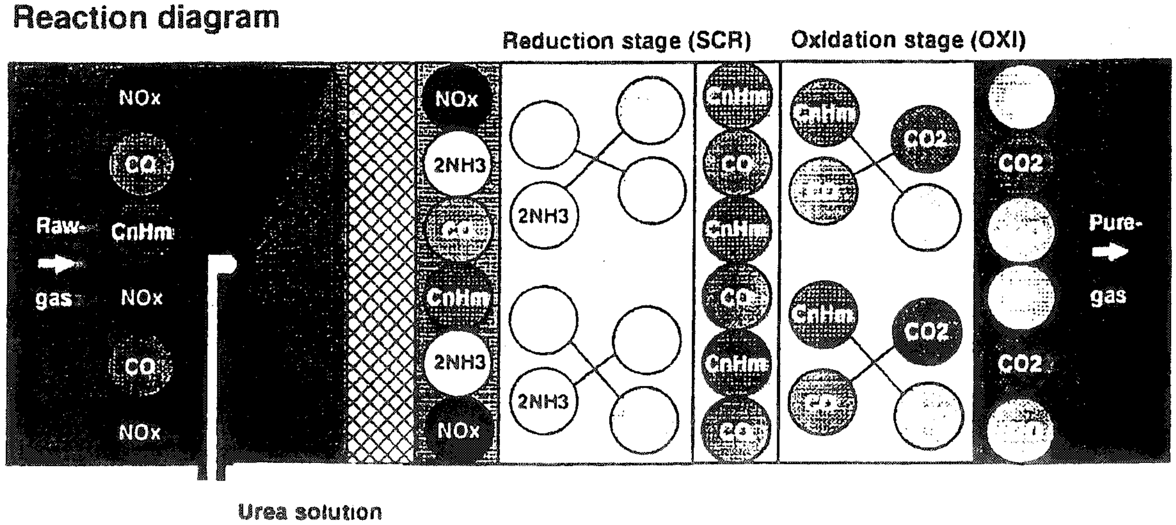
The Reactant

The Engelhard-Kaparta system works almost exclusively with urea as the reactant (although ammonia injection is available upon request). Urea offers great advantages over conventional ammonia systems due to its easy transport, safe storage and handling and economical cost. The injection module precisely controls the SCR chemical reaction.

The Oxidation Stage

If CO and HC reduction are required, modules are added with oxidation catalysts. The pollutant gases would then diffuse through to the surfaces of the ceramic honeycomb, contacting the catalyst to form hydrogen and carbon dioxide.

Reaction diagram



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SUPPLIER OF SCR SYSTEMS

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SCR Systems for NO_x Control - Diesel and Natural Gas Engines

29

Catalytic Air Pollution Control

Commercial Technology

Ronald M. Heck

Robert J. Farrauto

Engelhard Corporation
Research and Development

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1995

to the catalyst surface when operating at temperatures greater than 250° C (see Chapter 4). These reactive, often combustion-derived, hydrocarbons include alkenes, alkynes, aromatics, C_6^+ paraffins, and partially oxygenated hydrocarbons. Their conversion efficiency will depend primarily on their gas phase diffusivities and, as in CO oxidation, on the geometric surface area of the honeycomb catalyst.

The conversion rates of reactive hydrocarbons will always increase with increasing catalyst cell density, because the geometric surface area for reaction increases. However, the absolute conversion level for each species will depend on its diffusion rate in the exhaust gas. In general, larger, heavier molecules (like C_8 and C_9 molecules) will diffuse more slowly than smaller, lighter molecules such as ethylene. Table 11.1 gives the conversions of several reactive hydrocarbons over an abatement system designed for 90 percent CO removal. As the size of the hydrocarbon molecule increases, hydrocarbon conversion decreases as a result of decreased gas diffusivity. However, Table 11.1 shows that high conversion of reactive hydrocarbons can be achieved using typical CO abatement system designs with no additional catalyst.

11.5 OXIDATION OF UNREACTIVE, LIGHT PARAFFINS

The primary hydrocarbon types found in the exhaust of a natural gas fired combustion turbine are light paraffins, and these are among the least reactive molecules for oxidation. Methane, ethane, propane, butane, and (to a lesser extent) pentane) require special catalysts, higher temperatures, or both before they can be destroyed using practical volumes of catalyst in a combustion turbine exhaust.

Figure 11.5 is a graph of propane conversion as a function of temperature for three proprietary catalyst formulations, all of which contain different amounts and types of precious metals. For more difficult to oxidize hydrocarbons, a combination of Pt and Pd is preferred to optimize hydrocarbon conversion in the exhaust.

There has been one limitation on the application of the hybrid and paraffin catalyst formulations in combustion turbine exhausts: their sensitivity to sulfur compounds. Most natural gas contains negligible sulfur (1–2 vppm), but natural gas specifications typically allow up to 1 grain S/100 ft^3 (about 30 vppm sulfur). This

TABLE 11.1 Conversion of reactive hydrocarbons over standard Pt catalyst

Hydrocarbon compound	*Conversion (%)*
Carbon monoxide (CO)	90
Acetylene (C2H2)	86
Ethylene (C2H4)	85
Formaldehyde (CH2O)	77
Benzene (C6H6)	72
Toluene (C7H8)	71

ıtures greater than 250° C (see
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–2 vppm), but natural gas
(about 30 vppm sulfur). This

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90
86
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72
71

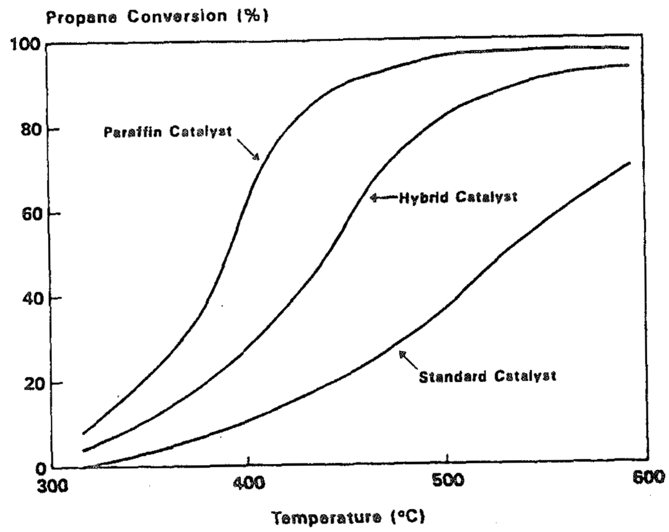

FIGURE 11.5 Propane conversion can be increased using catalyst optimized for light paraffins

level is similar to that found in sweetened refinery gas. Figure 11.6 shows propane conversion versus temperature over a standard Pt/γ-Al_2O_3-type catalyst for both 0 and 30 vppm SO_2 in the exhaust gas. This sulfur level is equivalent to much higher levels than might be present in natural gas turbine exhaust, but it was used in a laboratory study to accelerate the aging. This type of test has successfully predicted long-term performance in the exhaust of a turbine with much lower sulfur contents. Figure 11.6 shows that sulfur reduces the propane conversion from >40 percent at 425° C to about 5 percent.

Based on these experiences, more sulfur-tolerant catalysts have been developed for the control of light paraffins in natural gas fired combustion turbine exhausts. These catalysts have washcoats formulated to be less reactive with SO_3 than γ-Al_2O_3 and contain proprietary additives that suppress the oxidation of SO_2 to SO_3. In one such case, the addition of Rh or Pd to the Pt was found to suppress the SO_3 formation.[6] Figure 11.7 compares propane conversion activity for the improved and standard Pt/γ-Al_2O_3 catalyst.

11.6 CATALYST DEACTIVATION

There are three primary sources of catalyst poisons and contaminants in the exhausts of co-generation combustion turbines: fuel contaminants, boiler leaks, and turbine lubricants. Of the three, sulfur oxides from liquid fuels are the most

30

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E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**June 27, 2001**	**NO. PAGES 3**	
TO:	**EARTH TECH**	**FAX 978-371-2468**	
ATTN:	**Steven Babcock**		
	Engelhard Corp.		
	ATTN: Nancy Ellison		
FROM:	**Fred Booth**		**Ph 410-569-0297 // FAX 410-569-1841**

RE: **Mirant - Danville**
Camet® CO Catalyst System
Engelhard Budgetary Proposal EPB00354

We provide Engelhard Budgetary Proposal EPB00354 for One (1) Engelhard **Camet®** CO Catalyst system. This is per your FAX request of June 26, 2001.

We offer catalyst selection and pricing based on:

- CO Reduction from given inlet CO levels (lb/hr) to 4 ppmvd @ 15% O_2 (Duct Burner Fired) and 2 ppmvd @ 15% O_2 (Duct Burner Unfired);
- Advise % reductions for VOC (Non-Methane / Non-Ethane-50% Saturated) and Formaldehyde;
- Three (3) Year Performance Guarantee;
- Meeting assumed HRSG inside liner dimensions of 70 ft H x 26 ft W;
- Engelhard Scope: CO catalyst modules with internal frame and tongue seals and interface engineering;
- By Others: Existing Duct / catalyst housing (including any transitions), internal insulation, grooved internal liner sheets, frame supports and pedestals, catalyst loading door, personnel manway and sample ports.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

EARTH TECH
Mirant - Danville
CO Catalyst - Engelhard Budgetary Proposal EPB00354
June 27, 2001

ENGELHARD CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEM

DELIVERABLES: Equipment and services consisting of:
1. Catalyst modules;
2. Removable and replaceable sample catalysts;
3. Catalyst internal support frame and internal tongue seals;
4. Drawings showing installation details, loadings, and support requirements;
5. Installation and operating manuals;
6. Technical service for equipment installation

BUDGET PRICE:	**Delivery: FOB, plant gate, job site**	**Per Turbine**	**$465,000**
	Replacement CO Catalyst Modules	**Per Turbine**	**$390,000**

The materials are installed by others per Engelhard design.

SPENT CATALYST

Engelhard agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is not a hazardous material. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Twelve (12) months from date of start up or eighteen (18) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.
Expected Life:	5 to 7 Years

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings for Approval	3 – 4 weeks after notice to proceed
Material Delivery	fob, plant gate, Jobsite
Frame and Seals	16 - 18 weeks after approval and release for fabrication
Catalyst Modules	20 - 24 weeks after approval and release for fabrication

CO SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7FA Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	Designed for Gas Velocities within $\pm$15% of the mean velocity at the catalyst face
Temperature (At catalyst face):	Designed for Gas Temperatures within range $\pm 25^{O}$F of given average temperatures at all points at the catalyst face
CO Concentration (At catalyst face):	See Performance Data – Based on given CO in – lb/hr
CO Outlet:	To 4 ppmvd @ 15% O_2 (Duct Burner Fired) To 2 ppmvd @ 15% O_2 (Duct Burner Unfired)

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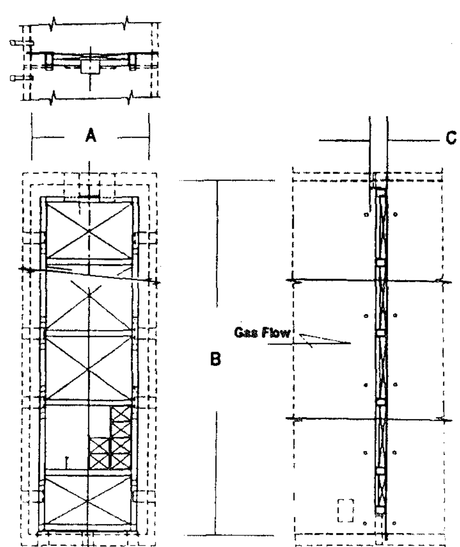
EARTH TECH
Mirant - Danville
CO Catalyst - Engelhard Budgetary Proposal EPB00354
June 27, 2001

PERFORMANCE DATA

GIVEN / CALCULATED DATA CASE	1	2
FUEL	NG	NG
DUCT BURNER - FIRED / UNFIRED	FIRED	UNFIRED
GIVEN GAS FLOW AFTER BURNER, lb/hr	3,281,000	3,922,000
GAS ANALYSIS - AFTER BURNER, % VOL. - N_2	67.20	75.20
O_2	10.70	12.80
CO_2	3.80	3.80
H_2O	17.50	7.30
Ar	0.80	0.90
CALC. GAS MOL. WT.	27.40	28.51
GIVEN INLET CO, lb/hr	56.2	32.0
CALC. INLET CO, ppmvd @ 15% O_2	15.1	7.5
GIVEN INLET VOC, lb/hr	N / A	N / A
CALC. INLET VOC, ppmvd @ 15% O_2	N / A	N / A
ASSUMED GAS TEMP. @ CO CATALYST, °F (+/-25)	650	620
DESIGN REQUIREMENTS CO OUT, ppmvd @ 15% O_2	4.0	2.0
VOC OUT, ppmvd @ 15% O_2	ADVISE	ADVISE
CO PRESSURE DROP - "WG MAX.		
GUARANTEED PERFORMANCE DATA		
CO CONVERSION, % - Min.	73.5%	73.2%
CO OUT, lb/hr - Max.	14.9	8.6
CO OUT, ppmvd @ 15% O_2	4.0	2.0
SO_2 -> SO_3 CONVERSION, % - Max.	7%	4%
FORMALDEHYDE CONVERSION, % - Min.	70%	70%
VOC** CONVERSION, % - Min.	36%	34%
VOC** OUT, lb/hr	N / A	N / A
VOC** OUT, ppmvd @ 15% O_2	N / A	N / A
** VOC - NON-METHANE / NON-ETHANE - 50% SATURATED		
CO PRESSURE DROP, "WG - Max.	0.6	0.6

CATALYST MODULES

The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Two (2) of the total modules are provided with four (4) replaceable catalyst test buttons in each module (eight total buttons provided).



INTERNAL SUPPORT FRAME & SEALS

The internal support frame and internal tongue seals are fabricated from standard structural steel (Stainless Steel - High Temperature / Carbon Steel - Low Temperature) members and shapes. Mechanical tongue and groove expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and liner sheet grooves, both designed by Engelhard.

Dimensions:

Inside Liner Width (A) 26 ft
Inside Liner Height (B) 70 ft
Catalyst + frame depth (C) 18" est.
Estimated Weight –
CO system 42,000 lb

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GT 24 Projects
US Gen / LaPaloma
CO Catalysts - Engelhard Proposal EPB98308-Rev. 2
March 8, 1999

ENGELHARD CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEMS

Engelhard Corporation offers to supply to ABB/CE the CAMET® CO metal substrate catalytic oxidation systems ("CO System") based upon technical data and site conditions provided and upon the design conditions in this proposal.

DELIVERABLES: BASE SCOPE equipment and services consisting of:

1. CAMET® metal substrate CO Catalyst modules;
2. Removable and replaceable sample catalysts (test buttons);
3. Engelhard provide catalyst internal support frame and internal tongue seals;
4. Drawings showing installation details, loadings, and support requirements;
5. Installation and operating manuals, including training video;
6. Technical service for inspection of equipment installation performed by others - maximum five days and two trips are provided per Unit.

PRICING PER UNIT: Delivery is FOB, Hiram, OH **Per HRSG**

Catalyst Modules and design of internal frame and seals	**$580,700**
Engelhard provide fabrication of internal frame and seals	**$ 52,400**
Total	**$633,100**

TERMS OF PAYMENT: Based on Base Scope above - All net thirty(30) days

- Invoice Thirty (30) percent upon approval of drawings and release for fabrication;
- Invoice Fifty-five (65) percent upon delivery of catalyst modules;
- Invoice Five (5) percent upon successful completion of an acceptance test, but not later than ninety (90) days after date of delivery of catalyst. If Buyer waives acceptance testing or does not hold acceptance tests within the time limits set forth herein, then payment shall be made as if acceptance testing had demonstrated the attainment of guaranteed performance
- Invoice balance of frame and seals cost upon delivery

SPENT CATALYST
Engelhard agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is not a hazardous material. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

ACCEPTANCE BY BUYER:
Buyer shall accept the CO System based upon satisfactory completion of a mutually acceptable performance test to be performed within ninety (90) days of start up date. If Buyer waives acceptance testing or does not hold acceptance tests within the time limits set forth herein, then payment shall be made as if acceptance testing had demonstrated the attainment of guaranteed performance.

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Eighteen (18) months operation - Not to exceed Twenty-eight (28) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.

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DOCUMENT / MATERIAL DELIVERY SCHEDULE

Ten (10) sets of start up, operating instructions, and maintenance manuals will be supplied thirty days before delivery.
Delivery 16 weeks after release for fabrication

QUALITY ASSURANCE and SAFETY
Engelhard's manufacturing is carried out under strict adherence to published quality control and statistical process control programs.and strict adherence to Corporate safety practices and procedures. Engelhard will supply copy of QA Manual.

TECHNICAL SERVICE
An Engelhard Technical Representative must inspect equipment fabrication and/or installation performed by others and review system operation annually through the guarantee period. If additional time over that noted above for inspections during fabrication / installation is required as a result of others, this additional time will be invoiced based on current cost for the Technical Representative of $1,000 per ten (10) hour day, $200 per hour for overtime, plus actual travel and living expenses incurred by the representative invoiced at cost.

CO SYSTEM DESIGN BASIS:	
Gas Flow from:	ABB GT24 Combustion Turbine
Gas Flow:	Horizontal
Fuel:	Natural Gas and Distillate Oil
Gas Flow Rate (At catalyst face):	Designs are based on Gas Velocity profile being within $\pm$15% of the mean velocity at the catalyst face.
Temperature (At catalyst face):	All Gas Temperatures must be within range of $\pm 25^{O}F$ of given average temperatures at the catalyst face.
CO Concentration (At catalyst face):	See Performance Data
VOC Composition	Assumed to be C_3H_x - 50% SATURATED / 50% UNSATURATED
Formaldehyde	See Performance Data
Pressure Drop:	See Performance Data

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TABLE A - Performance Data:

GIVEN / CALCULATED DATA					
CASE	1	2	3	G100N-1	G100S-1
AMBIENT	15	15	15	30	30
LOAD	Base	Base	Base	Base	Base
FUEL	NG	NG	NG	NG	NG
TURBINE EXHAUST FLOW, kg / s	398.2	414.1	391.9	389.3	409.1
TURBINE EXHAUST FLOW, lb/hr	3,160,338	3,286,529	3,110,338	3,089,679	3,246,562
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	74.63	70.19	74.57	74.40	68.75
O_2	11.32	9.91	11.31	11.29	9.63
CO_2	4.60	4.71	8.63	4.58	4.74
H_2O	8.56	14.36	4.60	8.84	16.07
Ar	0.89	0.84	0.89	0.89	0.82
SO2, lb/hr (based on 0.75 grains S/100 scf)	3.6	3.9	3.6	3.6	3.9
SO3, lb/hr (based on 0.75 grains S/100 scf)	0.4	0.5	0.4	0.4	0.5
GIVEN TURBINE CO, ppmvd @ 15% O_2	5	5	5	5	5
CALC. TURBINE CO, lb/hr	21	22	22	20	22
VOC as C3H8, ppmvd corr to 15% O2	0.4	0.4	0.4	0.4	0.4
VOC as C3H8, lb/hr	2.6	2.8	2.7	2.5	2.8
Formaldehyde as CH2O, ppmvd corr to 15% O2	0.9	0.9	0.9	0.9	0.9
Formaldehyde as CH2O, lb/hr	4.0	4.3	4.2	4.0	4.3
CALC. GAS MOL. WT.	28.46	27.83	29.50	28.42	27.65
GIVEN GAS TEMP. @ CO CATALYST, °C (+/-10)	332	324	335	333	338
GIVEN GAS TEMP. @ CO CATALYST, °F (+/-25)	630	615	635	631	640
DESIGN REQUIREMENTS					
CO, ppmvd corr to 15% O2	1	1	1	1	1
CO Reduction rate	73.9%	72.9%	74.7%	73.9%	72.9%
CO, lb/hr	5.3	6.1	5.5	5.2	6.1
VOC as C3H8, ppmvd corr to 15%O2	0.2	0.2	0.2		
VOC Reduction rate	39.6%	39.0%	40.0%		
VOC as C3H8, lb/hr	1.6	1.7	1.6		
Formaldehyde as CH2O, ppmvd corr to 15% O2	0.3	0.3	0.2		
Formaldehyd Reduction rate	72.1%	71.1%	72.8%		
Formaldehyde as CH2O, lb/hr	1.1	1.2	1.1		
CO PRESSURE DROP - "WG MAX.					
GUARANTEED PERFORMANCE DATA					
CO OUT, ppmvd @ 15% O_2	1	1	1	1	1
CO CONVERSION, % - Min.	85.8%	84.9%	86.3%	86.1%	85.3%
CO OUT, lb/hr - Max.	2.9	3.4	2.9	2.8	3.2
SO_2 -> SO_3 CONVERSION, % - Max.	4%	3%	5%	4%	5%
CO PRESSURE DROP, "WG - Max.	0.9	1.0	0.9	0.9	1.0
CO PRESSURE DROP, mBAR - Max.	2	2	2	2	2
VOC** OUT, ppmvd @ 15% O_2	0.2	0.2	0.2	0.2	0.2
VOC** CONVERSION, % - Min.	45%	45%	45%	45%	45%
VOC** OUT, lb/hr	1.4	1.6	1.5	1.4	1.5
** VOC - NON-METHANE / NON-ETHANE - 50% SATURATED					
Formaldehyde as CH2O, ppmvd corr to 15% O2 - OUT	0.2	0.2	0.1	0.1	0.2
Formaldehyd Reduction rate	83%	83%	84%	84%	83%
Formaldehyde as CH2O, lb/hr - OUT	0.7	0.7	0.7	0.6	0.7
CO CATALYST OUTLET SO2 lb/hr	3.5	3.8	3.4	3.5	3.8
SO3 lb/hr	0.6	0.6	0.6	0.6	0.7
H2S04	0.8	0.8	0.8	0.8	0.9

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TABLE A - Performance Data:

GIVEN / CALCULATED DATA — CASE	G100C18	G75N18	G50N18	G100N40	G100E40
AMBIENT	65	65	65	104	104
LOAD	Base	75	50	Base	Base
FUEL	NG	NG	NG	NG	NG
TURBINE EXHAUST FLOW, kg / s	393.5	313.1	257.3	360.0	371.2
TURBINE EXHAUST FLOW, lb/hr	3,123,036	2,484,810	2,042,386	2,857,162	2,946,051
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	67.92	74.08	74.30	74.26	73.64
O_2	9.46	11.76	12.39	11.44	11.17
CO_2	4.71	4.29	3.99	4.48	4.54
H_2O	17.10	8.98	8.43	8.93	9.77
Ar	0.81	0.89	0.89	0.89	0.88
SO2, lb/hr (based on 0.75 grains S/100 scf)	3.6	2.7	2.0	3.1	3.3
SO3, lb/hr (based on 0.75 grains S/100 scf)	0.4	0.3	0.2	0.4	0.4
GIVEN TURBINE CO, ppmvd @ 15% O_2	5	15	100	5	5
CALC. TURBINE CO, lb/hr	21	45	230	18	19
VOC as C3H8, ppmvd corr to 15% O2	0.4	0.4	0.7	0.4	0.4
VOC as C3H8, lb/hr	2.7	1.9	2.5	2.2	2.3
Formaldehyde as CH2O, ppmvd corr to 15% O2	0.9	3.0	3.0	0.9	0.9
Formaldehyde as CH2O, lb/hr	4.0	9.7	7.4	3.4	3.6
CALC. GAS MOL. WT.	27.54	28.38	28.41	28.40	28.32
GIVEN GAS TEMP. @ CO CATALYST, °C (+/-10)	332	314	302	328	327
GIVEN GAS TEMP. @ CO CATALYST, °F (+/-25)	630	597	576	622	621
DESIGN REQUIREMENTS					
CO, ppmvd corr to 15% O2	1	3	10	1	1
CO Reduction rate	74.1%	77.3%	90.0%	75.9%	75.2%
CO, lb/hr	5.3	10.3	23.0	4.2	4.5
VOC as C3H8, ppmvd corr to 15%O2		0.2	0.4		
VOC Reduction rate		41.1%	42.2%		
VOC as C3H8, lb/hr		1.1	1.5		
Formaldehyde as CH2O, ppmvd corr to 15% O2		0.7	0.7		
Formaldehyd Reduction rate		75.4%	77.9%		
Formaldehyde as CH2O, lb/hr		2.4	1.6		
CO PRESSURE DROP - "WG MAX.					
GUARANTEED PERFORMANCE DATA					
CO OUT, ppmvd @ 15% O_2	1	2	10	1	1
CO CONVERSION, % - Min.	85.7%	88.3%	90.2%	86.8%	86.5%
CO OUT, lb/hr - Max.	3.0	5.3	22.5	2.4	2.6
SO_2 -> SO_3 CONVERSION, % - Max.	4%	3%	2%	4%	4%
CO PRESSURE DROP, "WG - Max.	0.9	0.7	0.5	0.8	0.8
CO PRESSURE DROP, mBAR - Max.	2	2	1	2	2
VOC** OUT, ppmvd @ 15% O_2	0.2	0.2	0.4	0.2	0.2
VOC** CONVERSION, % - Min.	45%	46%	47%	46%	45%
VOC** OUT, lb/hr	1.5	1.0	1.3	1.2	1.3
** VOC - NON-METHANE / NON-ETHANE - 50% SATURATED					
Formaldehyde as CH2O, ppmvd corr to 15% O2 - OUT	0.1	0.4	0.4	0.1	0.1
Formaldehyd Reduction rate	84%	86%	88%	85%	84%
Formaldehyde as CH2O, lb/hr - OUT	0.7	1.3	0.9	0.5	0.6
CO CATALYST OUTLET SO2 lb/hr	3.5	2.6	2.0	3.0	3.1
SO3 lb/hr	0.6	0.4	0.3	0.5	0.5
H2S04	0.8	0.5	0.4	0.8	0.7

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TABLE A - Performance Data:

GIVEN / CALCULATED DATA CASE	G75N-1	G50N-1	G100N18	G100E18	G100S18
AMBIENT	30	30	65	65	65
LOAD	75	50	Base	Base	Base
FUEL	NG	NG	NG	NG	NG
TURBINE EXHAUST FLOW, kg / s	323.5	265.3	369.5	373.7	389.3
TURBINE EXHAUST FLOW, lb/hr	2,567,477	2,105,569	2,932,559	2,966,067	3,089,703
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	74.51	74.74	73.92	73.68	68.07
O_2	11.63	12.27	11.27	11.16	9.54
CO_2	4.42	4.12	4.53	4.55	4.68
H_2O	8.55	7.99	9.41	9.73	16.89
Ar	0.89	0.89	0.88	0.88	0.81
SO2, lb/hr (based on 0.75 grains S/100 scf)	2.8	2.2	3.3	3.4	3.6
SO3, lb/hr (based on 0.75 grains S/100 scf)	0.3	0.3	0.4	0.4	0.4
GIVEN TURBINE CO, ppmvd @ 15% O_2	15	100	5	5	5
CALC. TURBINE CO, lb/hr	48	244	19	19	21
VOC as C3H8, ppmvd corr to 15% O2	0.4	0.7	0.4	0.4	0.4
VOC as C3H8, lb/hr	2.0	2.7	2.4	2.4	2.6
Formaldehyde as CH2O, ppmvd corr to 15% O2	3.0	3.0	0.9	0.9	0.9
Formaldehyde as CH2O, lb/hr	11.1	8.5	3.6	3.7	4.0
CALC. GAS MOL. WT.	28.44	28.47	28.36	28.32	27.56
GIVEN GAS TEMP. @ CO CATALYST, °C (+/-10)	318	304	328	328	328
GIVEN GAS TEMP. @ CO CATALYST, °F (+/-25)	604	579	622	622	622
DESIGN REQUIREMENTS					
CO, ppmvd corr to 15% O2	3	10	1	1	1
CO Reduction rate	77.2%	90.0%	75.0%	74.8%	74.1%
CO, lb/hr	10.9	24.4	4.7	4.8	5.3
VOC as C3H8, ppmvd corr to 15%O2			0.2	0.2	0.2
VOC Reduction rate			40.1%	40.0%	39.6%
VOC as C3H8, lb/hr			1.4	1.4	1.6
Formaldehyde as CH2O, ppmvd corr to 15% O2			0.2	0.2	0.2
Formaldehyd Reduction rate			73.1%	73.0%	72.3%
Formaldehyde as CH2O, lb/hr			1.0	1.0	1.1
CO PRESSURE DROP - "WG MAX.		XXX			
GUARANTEED PERFORMANCE DATA					
CO OUT, ppmvd @ 15% O_2	2	10	1	1	1
CO CONVERSION, % - Min.	88.0%	90.0%	86.6%	86.5%	85.7%
CO OUT, lb/hr - Max.	5.8	24.4	2.5	2.6	3.0
SO_2 -> SO_3 CONVERSION, % - Max.	3%	2%	4%	4%	4%
CO PRESSURE DROP, "WG - Max.	0.7	0.5	0.8	0.8	0.9
CO PRESSURE DROP, mBAR - Max.	2	1	2	2	2
VOC** OUT, ppmvd @ 15% O_2	0.2	0.4	0.2	0.2	0.2
VOC** CONVERSION, % - Min.	46%	47%	45%	45%	45%
VOC** OUT, lb/hr	1.1	1.4	1.3	1.3	1.4
** VOC - NON-METHANE / NON-ETHANE - 50% SATURATED					
Formaldehyde as CH2O, ppmvd corr to 15% O2 - OUT	0.4	0.4	0.1	0.1	0.1
Formaldehyd Reduction rate	88%	88%	84%	84%	84%
Formaldehyde as CH2O, lb/hr - OUT	1.6	1.0	0.6	0.6	0.7
CO CATALYST OUTLET SO2 lb/hr	2.8	2.1	3.2	3.2	3.5
SO3 lb/hr	0.5	0.3	0.6	0.6	0.6
H2SO4	0.6	0.4	0.7	0.7	0.7

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March 8, 1999

TABLE A - Performance Data:

GIVEN / CALCULATED DATA CASE	G100S40	G100C40	G75N40	G50N40	G100C46
AMBIENT	104	104	104	104	115
LOAD	Base	Base	75	50	Base
FUEL	NG	NG	NG	NG	NG
TURBINE EXHAUST FLOW, kg / s	376.8	391.0	307.5	253.3	375.8
TURBINE EXHAUST FLOW, lb/hr	2,990,496	3,103,195	2,440,492	2,010,331	2,982,559
TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	73.64	67.86	74.45	74.67	66.61
O_2	11.17	9.46	12.00	12.62	9.16
CO_2	4.54	4.70	4.22	3.92	4.68
H_2O	9.77	17.17	8.44	7.90	18.75
Ar	0.88	0.81	0.89	0.89	0.80
SO2, lb/hr (based on 0.75 grains S/100 scf)	3.2	3.2	2.5	1.9	2.6
SO3, lb/hr (based on 0.75 grains S/100 scf)	0.4	0.4	0.3	0.2	0.3
GIVEN TURBINE CO, ppmvd @ 15% O_2	5	5	15	100	5
CALC. TURBINE CO, lb/hr	19	21	44	222	20
VOC as C3H8, ppmvd corr to 15% O2	0.4	0.4	0.4	0.7	0.4
VOC as C3H8, lb/hr	2.2	2.2	1.7	2.3	2.6
Formaldehyde as CH2O, ppmvd corr to 15% O2	0.9	0.9	3.0	3.0	0.9
Formaldehyde as CH2O, lb/hr	3.5	3.5	9.0	6.9	3.0
CALC. GAS MOL. WT.	28.32	27.53	28.43	28.47	27.35
GIVEN GAS TEMP. @ CO CATALYST, °C (+/-10)	327	340	316	302	338
GIVEN GAS TEMP. @ CO CATALYST, °F (+/-25)	621	644	601	576	640
DESIGN REQUIREMENTS					
CO, ppmvd corr to 15% O2	1	1	3	10	1
CO Reduction rate	75.7%	75.7%	77.9%	90.0%	80.0%
CO, lb/hr	4.4	4.1	9.3	22.2	4.2
VOC as C3H8, ppmvd corr to 15%O2					
VOC Reduction rate					
VOC as C3H8, lb/hr					
Formaldehyde as CH2O, ppmvd corr to 15% O2					
Formaldehyd Reduction rate					
Formaldehyde as CH2O, lb/hr					
CO PRESSURE DROP - "WG MAX.					
GUARANTEED PERFORMANCE DATA					
CO OUT, ppmvd @ 15% O_2	1	1	2	10	1
CO CONVERSION, % - Min.	86.3%	85.9%	88.6%	90.4%	86.3%
CO OUT, lb/hr - Max.	2.6	3.0	5.0	21.3	2.8
SO_2 -> SO_3 CONVERSION, % - Max.	4%	5%	3%	2%	5%
CO PRESSURE DROP, "WG - Max.	0.8	0.9	0.6	0.5	0.9
CO PRESSURE DROP, mBAR - Max.	2	2	2	1	2
VOC** OUT, ppmvd @ 15% O_2	0.2	0.2	0.2	0.4	0.2
VOC** CONVERSION, % - Min.	45%	45%	48%	47%	45%
VOC** OUT, lb/hr	1.2	1.2	0.9	1.2	1.4
** VOC - NON-METHANE / NON-ETHANE - 50% SATURATED					
Formaldehyde as CH2O, ppmvd corr to 15% O2 - OUT	0.1	0.1	0.4	0.4	0.1
Formaldehyd Reduction rate	84%	84%	86%	88%	84%
Formaldehyde as CH2O, lb/hr - OUT	0.5	0.6	1.2	0.8	0.5
CO CATALYST OUTLET SO2 lb/hr	3.0	3.0	2.4	1.8	2.5
SO3 lb/hr	0.5	0.6	0.4	0.3	0.5
H2S04	0.6	0.7	0.5	0.3	0.6

ENGELHARD

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ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
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2205 CHEQUERS COURT
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PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com

DATE:	December 30, 1999	NO. PAGES	3
TO:	J. PHYLLIS FOX ATTN: Phyllis Fox ENGELHARD ATTN: Nancy Ellison	via e-mail	
FROM:	Fred Booth	Ph 410-569-0297 // FAX 410-569-1841	

RE: **CO Oxidation Catalyst**
Engelhard Budgetary Proposal EPB99655

Dear Ms. Fox,

We provide Engelhard Budgetary Proposal EPB99655 for Engelhard **Camet®** CO Oxidation Catalyst systems per your Request for Budgetary Quotation.

We offer catalyst selections and pricing are based on:

- Option 1 – 33.3% CO Reduction from inlet level CO of 9 ppmvd @ 15% O_2;
- Option 2 – 90% CO Reduction from inlet level CO of 9 ppmvd @ 15% O_2;
- Advise VOC and Formaldehyde reductions for each Option;
- Meeting assumed inside liner dimensions inside HRSG of 64'-0" x 23'-0" W;
- Three (3) Year Performance Guarantee;
- Scope: Typical to HRSG Supplier
  - CO catalyst modules with internal frame and tongue seals with interface engineering only.
  - Duct / catalyst housing (including any transitions), internal insulation, grooved internal liner sheets, and frame supports and pedestals are provided by others, along with catalyst loading door, personnel manway and sample ports.

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

J. Phyllis Fox
CO Oxidation Catalysts
Engelhard Budgetary Proposal EPB99655
December 30, 1999

ENGELHARD CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEM

DELIVERABLES: Equipment and services consisting of:

1. Catalyst modules;
2. Removable and replaceable sample catalysts;
3. Catalyst internal support frame and internal tongue seals;
4. Drawings showing installation details, loadings, and support requirements;
5. Installation and operating manuals;
6. Technical service for equipment installation - two trips - five days total included: one trip for inspection of frame installation and one trip for installation of catalyst modules.

BUDGET PRICE: Delivery: FOB, plant gate, job site **See Performance Data**

SPENT CATALYST

Engelhard agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is not a hazardous material. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Twelve (12) months from date of start up or eighteen (18) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.
Expected Life:	5 to 7 Years

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings for Approval	3 – 4 weeks after notice to proceed with complete engineering specifications and Engelhard receipt of all engineering details.
Material Delivery	fob, plant gate, Jobsite
Frame and Seals	16 weeks after approval and release for fabrication
Catalyst Modules	16 weeks after approval and release for fabrication

CATALYST MODULES

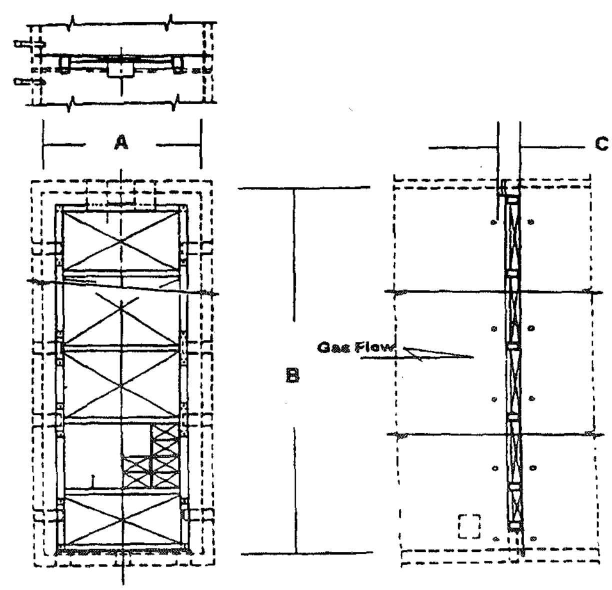
The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Eight (8) replaceable catalyst test buttons will be provided.

INTERNAL SUPPORT FRAME & SEALS

The internal support frame and internal tongue seals are fabricated from standard structural steel (Stainless Steel - High Temperature / Carbon Steel - Low Temperature) members and shapes. Mechanical tongue and groove expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and bottom pedestals and liner sheet grooves, both designed by Engelhard.

Dimensions:

Inside Liner	(A)	23'-0"
Inside Liner	(B)	64'-0"
Catalyst + frame depth	(C)	18" est.



The equipment is supplied by Engelhard and installed by others in accordance with the Engelhard design.

ENGELHARD

J. Phyllis Fox
CO Oxidation Catalysts
Engelhard Budgetary Proposal EPB99655
December 30, 1999

CO SYSTEM DESIGN BASIS:	
Gas Flow from:	Combustion Turbine
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	Designed for Gas Velocities within ±15% of the mean velocity at the catalyst face
Temperature (At catalyst face):	Assumed 750°F
HRSG Cross Section:	64 ft x 23 ft - Inside Liner Sheets
CO Concentration (At catalyst face):	9 ppmvd @ 15% O_2
CO Outlet:	33.3% and 90% Reduction
VOC Performance:	Assumed composition – Non-Methane / Non-Ethane - 50% Saturated

Table A - Performance Data // Budget Prices

GIVEN / CALCULATED DATA	CASE	OPTION 1	OPTION 2
	FUEL	NG	NG
	TURBINE EXHAUST FLOW, lb/hr	3,550,000	3,550,000
	TURBINE EXHAUST GAS ANALYSIS, % VOL. - N_2	74.19	74.19
	O_2	12.31	12.31
	CO_2	3.83	3.83
	H_2O	8.79	8.79
	Ar	0.88	0.88
	GIVEN TURBINE CO, ppmvd @ 15% O_2	9	9
	CALC. TURBINE CO, lb/hr	36.1	36.1
	ASSUMED TURBINE VOC, ppmvd @ 15% O_2	3.0	3.0
	CALC. TURBINE VOC, lb/hr	6.9	6.9
	TURBINE FORMALDEHYDE, ppmvd @ 15% O_2	N / A	N / A
	TURBINE EXHAUST SO_2 - ppm	0.4	0.4
	ASSUMED GAS TEMP. @ CO CATALYST, °F (+/-25)	750	750
DESIGN REQUIREMENTS	CO OUT, ppmvd @ 15% O_2	6	0.9
	CO PRESSURE DROP - "WG MAX.		
GUARANTEED PERFORMANCE DATA			
	CO CONVERSION, % - Min.	33.3%	90.0%
	CO OUT, lb/hr - Max.	24.1	3.6
	CO OUT, ppmvd @ 15% O_2	6.0	0.9
	CO PRESSURE DROP, "WG - Max.	0.4	1.7
EXPECTED PERFORMANCE			
	CO CONVERSION, %	49%	92%
	SO_2 -> SO_3 CONVERSION, % - Max.	10%	32%
	VOC** CONVERSION, % - Min.	18%	35%
	FORMALDEHYDE CONVERSION - % - Min.	36%	87%
	CO SYSTEM	$394,000	$690,000
	REPLACEMENT CO CATALYST MODULES	$299,000	$596,000

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EPRI EPRI TR-105646

GRI GRI 95/0200

Gas-Fired Boiler and Turbine Air Toxics Summary Report

- Topical Report -

August, 1996

Prepared for:

Paul Chu and Barbara Toole-O'Neil
Toxic Substances Control
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94303

Robert A. Lott
Environment & Safety
Gas Research Institute
8600 West Bryn Mawr Ave.
Chicago, IL 60631-3562

Prepared by:

Carnot Technical Services
15991 Red Hill Ave., Suite 110
Tustin, CA 92780-7388

TABLE S-1
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED UTILITY BOILERS

Compound	B&W Opposed Fired Boiler: Full Load 330 MWe 3,300 MMBtu/hr		B&W Opposed Fired Boiler: Minimum Load 122 MWe 1,221 MMBtu/hr		CE Tangentially-Fired Boiler: Full Load 750 MWe 7,500 MMBtu/hr		CE Tangentially-Fired Boiler: Minimum Load 150 MWe 1,500 MMBtu/hr	
<u>Metals (1)</u>								
•Barium	5.70 lb/10^{12}Btu	0.08 tpy	NT	NT	(2)	(2)	NT	NT
•Chromium	1.08 lb/10^{12}Btu	0.02 tpy	NT	NT	1.10 lb/10^{12}Btu	0.04 tpy	NT	NT
•Copper	1.20 lb/10^{12}Btu	0.02 tpy	NT	NT	(2)	(2)	NT	NT
•Nickel	1.19 lb/10^{12}Btu	0.02 tpy	NT	NT	3.60 lb/10^{12}Btu	0.12 tpy	NT	NT
•Vanadium	0.46 lb/10^{12}Btu	0.01 tpy	NT	NT	3.20 lb/10^{12}Btu	0.11 tpy	NT	NT
<u>PAH (1)</u>								
•Fluorene	ND	ND	NT	NT	0.003 lb/10^{12}Btu	0.0001 tpy	NT	NT
•Phenanthrene	0.016 lb/10^{12}Btu	0.0002 tpy	NT	NT	0.010 lb/10^{12}Btu	0.0003 tpy	NT	NT
•2-Methylnaphthalene	0.042 lb/10^{12}Btu	0.0006 tpy	NT	NT	0.009 lb/10^{12}Btu	0.0003 tpy	NT	NT
<u>PCB</u>	ND	ND	NT	NT	NT	NT	NT	NT
<u>VOC</u>								
•Formaldehyde	5.9 lb/10^{12}Btu	0.09 tpy	5.5 lb/10^{12}Btu	0.03 tpy	11.9 lb/10^{12}Btu	0.39 tpy	2.5 lb/10^{12}Btu	0.02 tpy
•Benzene	1.4 lb/10^{12}Btu	0.02 tpy	1.1 lb/10^{12}Btu	0.01 tpy	ND	ND	ND	ND
•Toluene	13.3 lb/10^{12}Btu	0.19 tpy	2.8 lb/10^{12}Btu	0.01 tpy	2.2 lb/10^{12}Btu	0.07 tpy	4.2 lb/10^{12}Btu	0.03 tpy
<u>Hydrocarbons</u>								
•Total HC as CH_4	2.0 x 10^{-4} lb/MMBtu	3 tpy	1.0 x 10^{-4} lb/MMBtu	1 tpy	NT	NT	NT	NT
•CH_4	NT	NT	NT	NT	ND	ND	ND	ND
•TGNMO	NT	NT	NT	NT	0.03 lb/MMBtu	821 tpy	0.02 lb/MMBtu	99 tpy
<u>NO_x and CO</u>								
•NO_x	0.12 lb/MMBtu	1,734 tpy	0.07 lb/MMBtu	369 tpy	0.13 lb/MMBtu	4,271 tpy	0.05 lb/MMBtu	296 tpy
•CO	0.06 lb/MMBtu	867 tpy	ND	ND	0.08 lb/MMBtu	2,628 tpy	ND	ND

Notes: ND = not detected.
NT = not tested.
All values are for baseline conditions. See the body of the report for selected "low NO_x" conditions.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
(1) Only those compounds that were measured at levels more than twice the field blank level are shown. See Section 3.1 for more information on data handling procedures.
(2) Detected at the field blank level.

TABLE S-2
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED UTILITY TURBINES

Compound	Westinghouse 501AA Turbine				GE Frame 7 Turbine			
	Full Load 55 ~~330~~ MWe 789 ~~3,300~~ MMBtu/hr		Minimum Load ~~122~~ MWe 236 ~~1,221~~ MMBtu/hr		Full Load 150 ~~750~~ MWe 1624 ~~7,500~~ MMBtu/hr		Minimum Load ~~150~~ MWe 487 ~~1,500~~ MMBtu/hr	
Metals (1)								
•Barium	6.62 lb/10^{12}Btu	0.023 tpy	NT	NT	3.80 lb/10^{12}Btu	0.027 tpy	NT	NT
•Chromium	1.85 lb/10^{12}Btu	0.006 tpy	NT	NT	1.90 lb/10^{12}Btu	0.014 tpy	NT	NT
•Copper	3.13 lb/10^{12}Btu	0.011 tpy	NT	NT	6.20 lb/10^{12}Btu	0.044 tpy	NT	NT
•Lead	(2)	(2)	NT	NT	0.53 lb/10^{12}Btu	0.004 tpy	NT	NT
•Manganese	3.47 lb/10^{12}Btu	0.012 tpy	NT	NT	(2)	(2)	NT	NT
•Nickel	1.60 lb/10^{12}Btu	0.006 tpy	NT	NT	1.20 lb/10^{12}Btu	0.009 tpy	NT	NT
PAH (1)								
•Phenanthrene	0.111 lb/10^{12}Btu	0.0004 tpy	NT	NT	(2)	(2)	NT	NT
•2-Methylnaphthalene	0.162 lb/10^{12}Btu	0.0006 tpy	NT	NT	(2)	(2)	NT	NT
PCB	ND	ND	NT	NT	ND	ND	NT	NT
PCDD/PCDF	(2)	(2)	NT	NT	(2)	(2)	NT	NT
VOC								
•Formaldehyde	87 lb/10^{12}Btu	0.30 tpy	985 lb/10^{12}Btu	1.02 tpy	15 lb/10^{12}Btu	0.11 tpy	7,539 lb/10^{12}Btu	16.09 tpy
•Benzene	6.4 lb/10^{12}Btu	0.02 tpy	10.1 lb/10^{12}Btu	0.01 tpy	1.3 lb/10^{12}Btu	0.01 tpy	9.9 lb/10^{12}Btu	0.02 tpy
•Toluene	60 lb/10^{12}Btu	0.21 tpy	86 lb/10^{12}Btu	0.09 tpy	21 lb/10^{12}Btu	0.15 tpy	206 lb/10^{12}Btu	0.44 tpy
Hydrocarbons								
•Total HC as CH_4	9.8 x 10^{-3}lb/MMBtu	34 tpy	1.6 x 10^{-2}lb/MMBtu	16 tpy	3.4 x 10^{-3}lb/MMBtu	24 tpy	5.2 x 10^{-2}lb/MMBtu	111 tpy
•CH_4	ND	ND	ND	ND	ND	ND	1.5 x 10^{-3}lb/MMBtu	3 tpy
•TGNMO	1.0 x 10^{-2}lb/MMBtu	35 tpy	1.6 x 10^{-2}lb/MMBtu	17 tpy	7.9 x 10^{-3}lb/MMBtu	56 tpy	1.1 x 10^{-2}lb/MMBtu	23 tpy
NO_x and CO								
•NO_x	0.45 lb/MMBtu	1,538 tpy	0.23 lb/MMBtu	235 tpy	0.13 lb/MMBtu	953 tpy	0.15 lb/MMBtu	316 tpy
•CO	0.005 lb/MMBtu	17 tpy	0.111 lb/MMBtu	115 tpy	0.002 lb/MMBtu	14 tpy	0.635 lb/MMBtu	1,355 tpy

Notes: ND = not detected.
NT = not tested.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
(1) Only those compounds that were measured at levels more than twice the field blank level are shown. See Section 3.1 for more information on data handling procedures.
(2) Detected at the field blank level.

TABLE S-3
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED GE INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

Compound	GE Frame 3				GE LM1500			
	Full Load 7.7 MWeq 87 MMBtu/hr		Minimum Load 3.9 MWeq 44 MMBtu/hr		Full Load 10.6 MWeq 145 MMBtu/hr		Minimum Load 2.7 MWeq 36 MMBtu/hr	
VOC								
•Formaldehyde	260 lb/10^{12}Btu	0.10 tpy	419 lb/10^{12}Btu	0.08 tpy	4,189 lb/10^{12}Btu	2.66 tpy	25,450 lb/10^{12}Btu	4.04 tpy
•Benzene	3.4 lb/10^{12}Btu	0.001 tpy	4.2 lb/10^{12}Btu	0.001 tpy	39 lb/10^{12}Btu	0.025 tpy	2,359 lb/10^{12}Btu	0.375 tpy
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons								
•CH_4	ND	ND	0.012 lb/MMBtu	2 tpy	0.029 lb/MMBtu	18 tpy	2.17 lb/MMBtu	345 tpy
•TGNMO	0.008 lb/MMBtu	3 tpy	0.011 lb/MMBtu	2 tpy	0.013 lb/MMBtu	8 tpy	0.274 lb/MMBtu	44 tpy
NO_x, CO, SO_2, N_2O								
•NO_x	0.73 lb/MMBtu	278 tpy	0.51 lb/MMBtu	97 tpy	0.36 lb/MMBtu	229 tpy	0.07 lb/MMBtu	11 tpy
•CO	0.004 lb/MMBtu	2 tpy	0.018 lb/MMBtu	3 tpy	0.158 lb/MMBtu	100 tpy	3.57 lb/MMBtu	567 tpy
•SO_2	1.8×10^{-4}lb/MMBtu	0.07 tpy	2.3×10^{-4}lb/MMBtu	0.04 tpy	2.4×10^{-4}lb/MMBtu	0.15 tpy	1.8×10^{-4}lb/MMBtu	0.03 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
MWeq = 1,340 hp

TABLE S-4
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR TWO GAS-FIRED ROLLS ROYCE INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

Compound	Rolls Royce Avon				Rolls Royce Spey			
	Full Load 10.7 MWeq 158 MMBtu/hr		Minimum Load 2.7 MWeq 40 MMBtu/hr		Full Load 12.2 MWeq 132 MMBtu/hr		Minimum Load 3.1 MWeq 33 MMBtu/hr	
VOC								
•Formaldehyde	5,607 lb/10^{12}Btu	3.88 tpy	14,997 lb/10^{12}Btu	2.59 tpy	18.5 lb/10^{12}Btu	0.01 tpy	13,227 lb/10^{12}Btu	1.91 tpy
•Benzene	15.7 lb/10^{12}Btu	0.011 tpy	53 lb/10^{12}Btu	0.009 tpy	5.7 lb/10^{12}Btu	0.003 tpy	63 lb/10^{12}Btu	0.009 tpy
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons								
•CH_4	0.085 lb/MMBtu	ND	0.504 lb/MMBtu	87 tpy	0.012 lb/MMBtu	7 tpy	0.039 lb/MMBtu	6 tpy
•TGNMO	0.031 lb/MMBtu	21 tpy	0.110 lb/MMBtu	19 tpy	0.004 lb/MMBtu	2 tpy	0.076 lb/MMBtu	11 tpy
NO_x, CO, SO_2, N_2O								
•NO_x	0.237 lb/MMBtu	164 tpy	0.123 lb/MMBtu	21 tpy	0.575 lb/MMBtu	332 tpy	0.133 lb/MMBtu	77 tpy
•CO	0.410 lb/MMBtu	284 tpy	1.30 lb/MMBtu	225 tpy	0.20 lb/MMBtu	29 tpy	0.906 lb/MMBtu	131 tpy
•SO_2	3.0 x 10^{-4}lb/MMBtu	0.21 tpy	2.9 x 10^{-4}lb/MMBtu	0.05 tpy	2.8 x 10^{-4}lb/MMBtu	0.16 tpy	3.1 x 10^{-4}lb/MMBtu	0.05 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions = emissions factor x heat input x 8,760 hours of operation per year.
MWeq = 1,340 hp

TABLE S-5
HAZARDOUS AND CRITERIA AIR POLLUTANT SUMMARY FOR THREE GAS-FIRED SOLAR INDUSTRIAL TURBINES USED FOR GAS TRANSMISSION

Compound	Mars T12000				Mars T14000				Mars T14000 SoLoNOx			
	Full Load 9.4 MWeq 100 MMBtu/hr		Minimum Load 2.4 MWeq 25 MMBtu/hr		Full Load 10.9 MWeq 110 MMBtu/hr		Minimum Load 2.7 MWeq 28 MMBtu/hr		Full Load 10.9 MWeq 110 MMBtu/hr		Minimum Load 3.8 MWeq 39 MMBtu/hr	
VOC												
•Formaldehyde	15.6 lb/10^{12}Btu	0.01 tpy	9,430 lb/10^{12}Btu	1.03 tpy	2.2 lb/10^{12}Btu	0.00 tpy	2,485 lb/10^{12}Btu	0.30 tpy	14.6 lb/10^{12}Btu	0.01 tpy	20,347 lb/10^{12}Btu	3.43 tpy
•Benzene	2.0 lb/10^{12}Btu	0.001 tpy	10.2 lb/10^{12}Btu	0.001 tpy	1.3 lb/10^{12}Btu	0.001 tpy	2.4 lb/10^{12}Btu	0.000 tpy	2.9 lb/10^{12}Btu	0.001 tpy	67 lb/10^{12}Btu	0.011 tpy
•Toluene	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT	NT
Hydrocarbons												
•CH_4	ND	ND	0.207 lb/MMBtu	23 tpy	ND	ND	0.019 lb/MMBtu	2 tpy	0.003 lb/MMBtu	1 tpy	2.66 lb/MMBtu	449 tpy
•TGNMO	0.010 lb/MMBtu	4 tpy	0.043 lb/MMBtu	5 tpy	0.006 lb/MMBtu	3 tpy	ND	ND	0.003 lb/MMBtu	1 tpy	0.368 lb/MMBtu	62 tpy
NO_x, CO, SO_2, N_2O												
•NO_x	0.517 lb/MMBtu	226 tpy	0.121 lb/MMBtu	13 tpy	0.606 lb/MMBtu	292 tpy	0.191 lb/MMBtu	23 tpy	0.099 lb/MMBtu	48 tpy	0.110 lb/MMBtu	19 tpy
•CO	0.006 lb/MMBtu	3 tpy	1.25 lb/MMBtu	137 tpy	0.005 lb/MMBtu	2 tpy	0.220 lb/MMBtu	26 tpy	0.015 lb/MMBtu	7 tpy	4.90 lb/MMBtu	826 tpy
•SO_2	2.2×10^{-4}lb/MMBtu	0.10 tpy	1.9×10^{-4}lb/MMBtu	0.02 tpy	ND	ND	ND	ND	2.1×10^{-4}lb/MMBtu	0.10 tpy	2.3×10^{-4}lb/MMBtu	0.04 tpy
•N_2O	NT	NT	NT	NT	NT	NT	NT	NT	0.004 lb/MMBtu	2 tpy	0.587 lb/MMBtu	99 tpy

Notes:
ND = not detected.
NT = not tested.
Tons per year (tpy) emissions are based on 8,760 hours of operation.
MWeq = 1,340 hp

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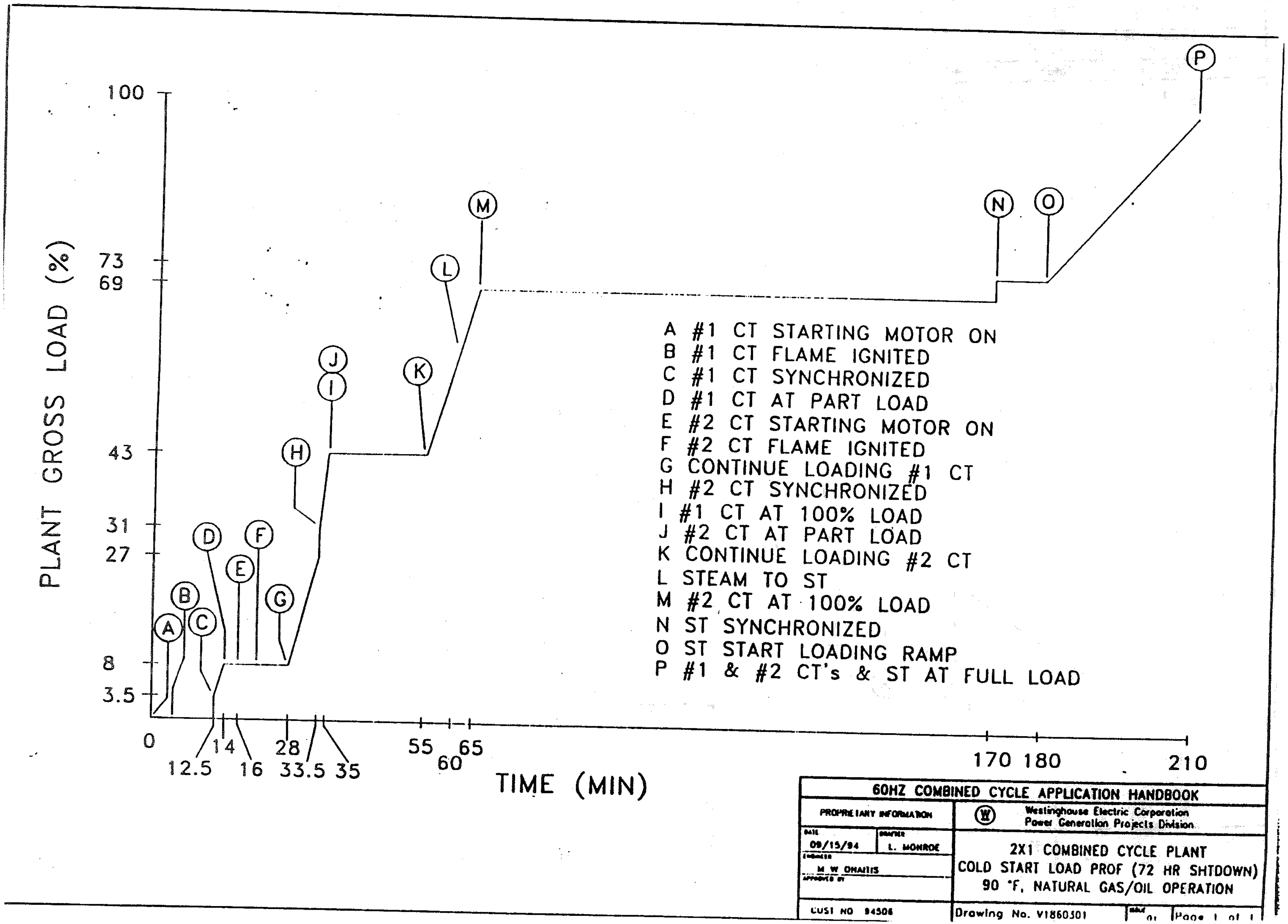
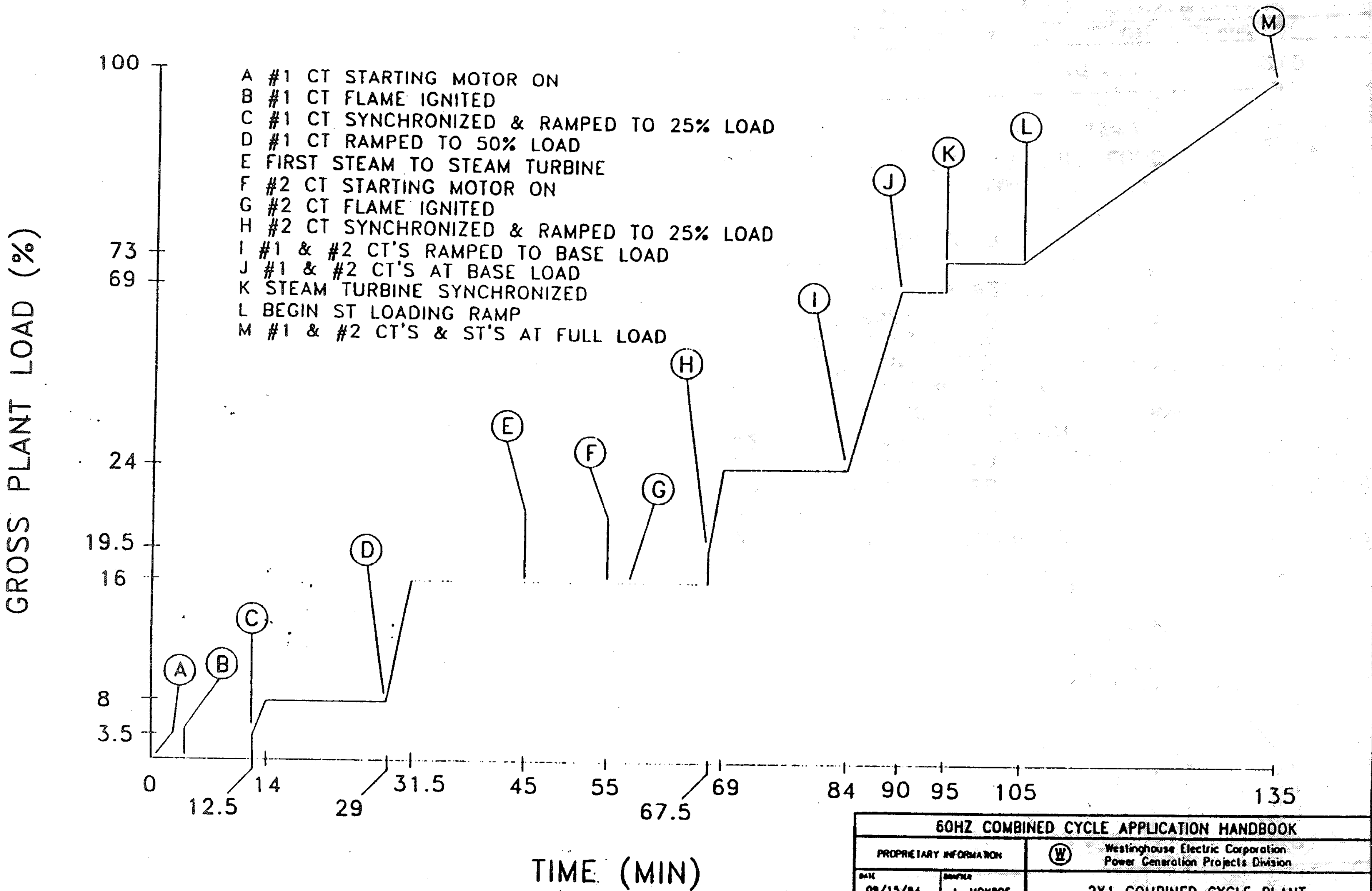
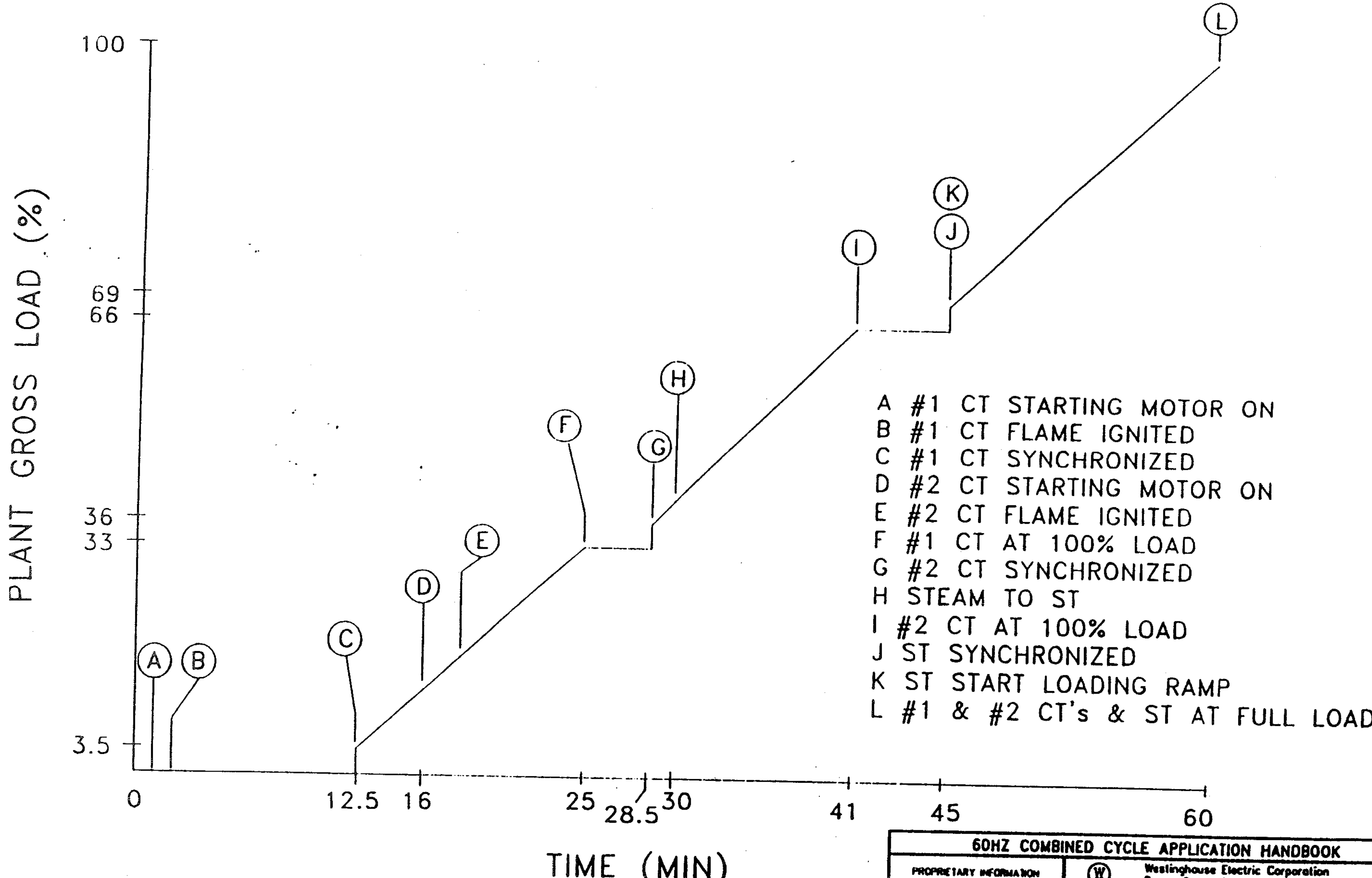

PLANT GROSS LOAD (%)
100
73
69
43
31
27
8
3.5
0
12.5
14
16
28
33.5
35
55
60
65
170
180
210
TIME (MIN)
A #1 CT STARTING MOTOR ON
B #1 CT FLAME IGNITED
C #1 CT SYNCHRONIZED
D #1 CT AT PART LOAD
E #2 CT STARTING MOTOR ON
F #2 CT FLAME IGNITED
G CONTINUE LOADING #1 CT
H #2 CT SYNCHRONIZED
I #1 CT AT 100% LOAD
J #2 CT AT PART LOAD
K CONTINUE LOADING #2 CT
L STEAM TO ST
M #2 CT AT 100% LOAD
N ST SYNCHRONIZED
O ST START LOADING RAMP
P #1 & #2 CT's & ST AT FULL LOAD
60HZ COMBINED CYCLE APPLICATION HANDBOOK
PROPRIETARY INFORMATION
Westinghouse Electric Corporation
Power Generation Projects Division
09/15/94
L. MONROE
M. W. OMAITIS
2X1 COMBINED CYCLE PLANT
COLD START LOAD PROF (72 HR SHTDOWN)
90 °F, NATURAL GAS/OIL OPERATION
CUST NO 94506
Drawing No. V1860301
Page 1 of 1



60HZ COMBINED CYCLE APPLICATION HANDBOOK	
PROPRIETARY INFORMATION	Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/84 DRAFTER L. MONROE ENGINEER M. W. ONAITIS APPROVED BY	2X1 COMBINED CYCLE PLANT WARM START LOAD PROF (48 HR SHTDOWN) 90 °F, NATURAL GAS/OIL OPERATION
CUST NO. 94506	Drawing No. V1860201 ISSUE 01 Page 1 of 1



60HZ COMBINED CYCLE APPLICATION HANDBOOK	
PROPRIETARY INFORMATION	Westinghouse Electric Corporation Power Generation Projects Division
DATE 09/15/94 / DRAFTER L. MONROE / ENGINEER M W ONAITIS / APPROVED BY	2X1 COMBINED CYCLE PLANT HOT START LOAD PROF (8 HR SHTDOWN) 90 °F, NATURAL GAS/OIL OPERATION
CUST NO. 94506	Drawing No. V1860101 / SCALE 01 / Page 1 of 1

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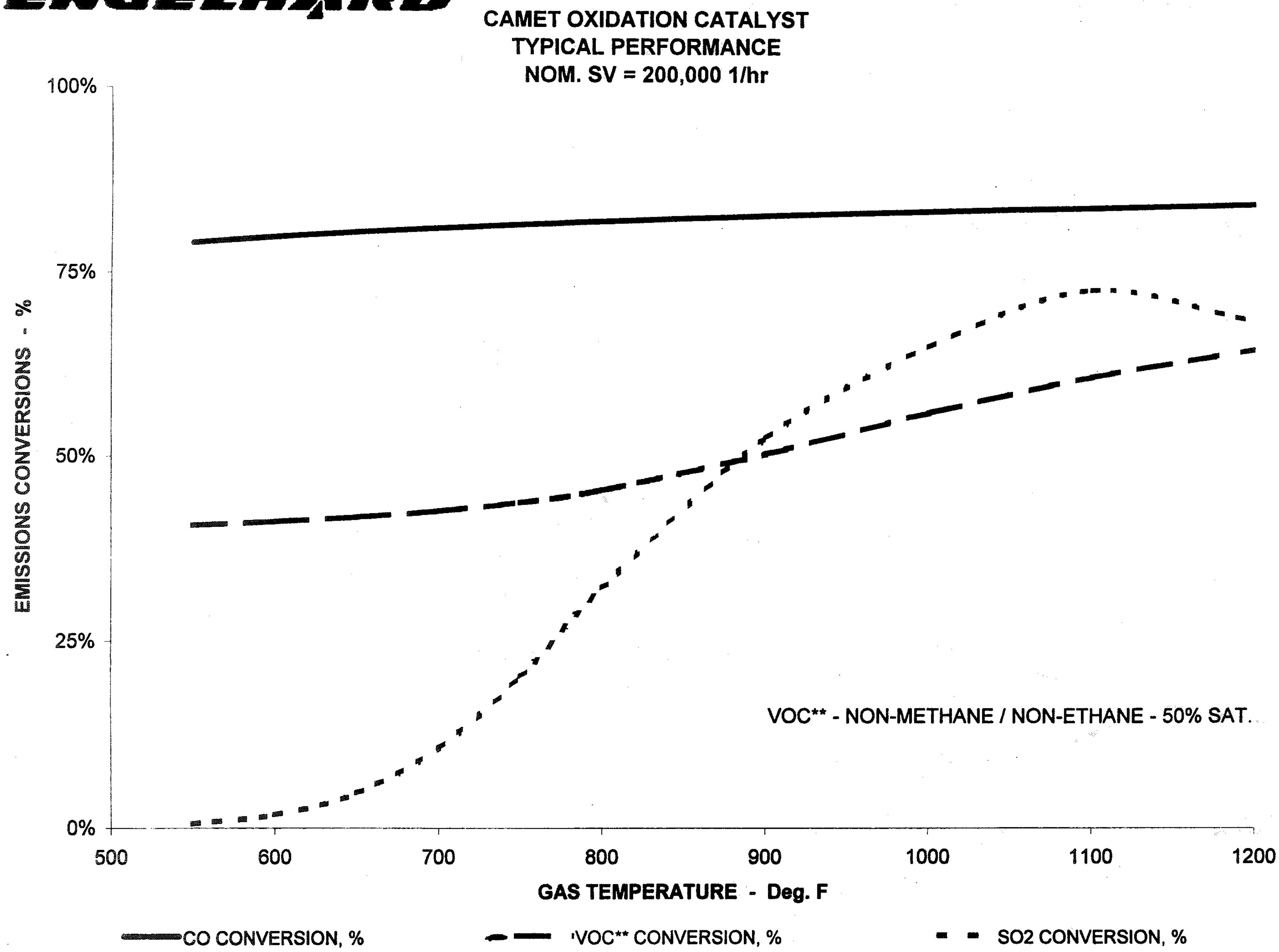
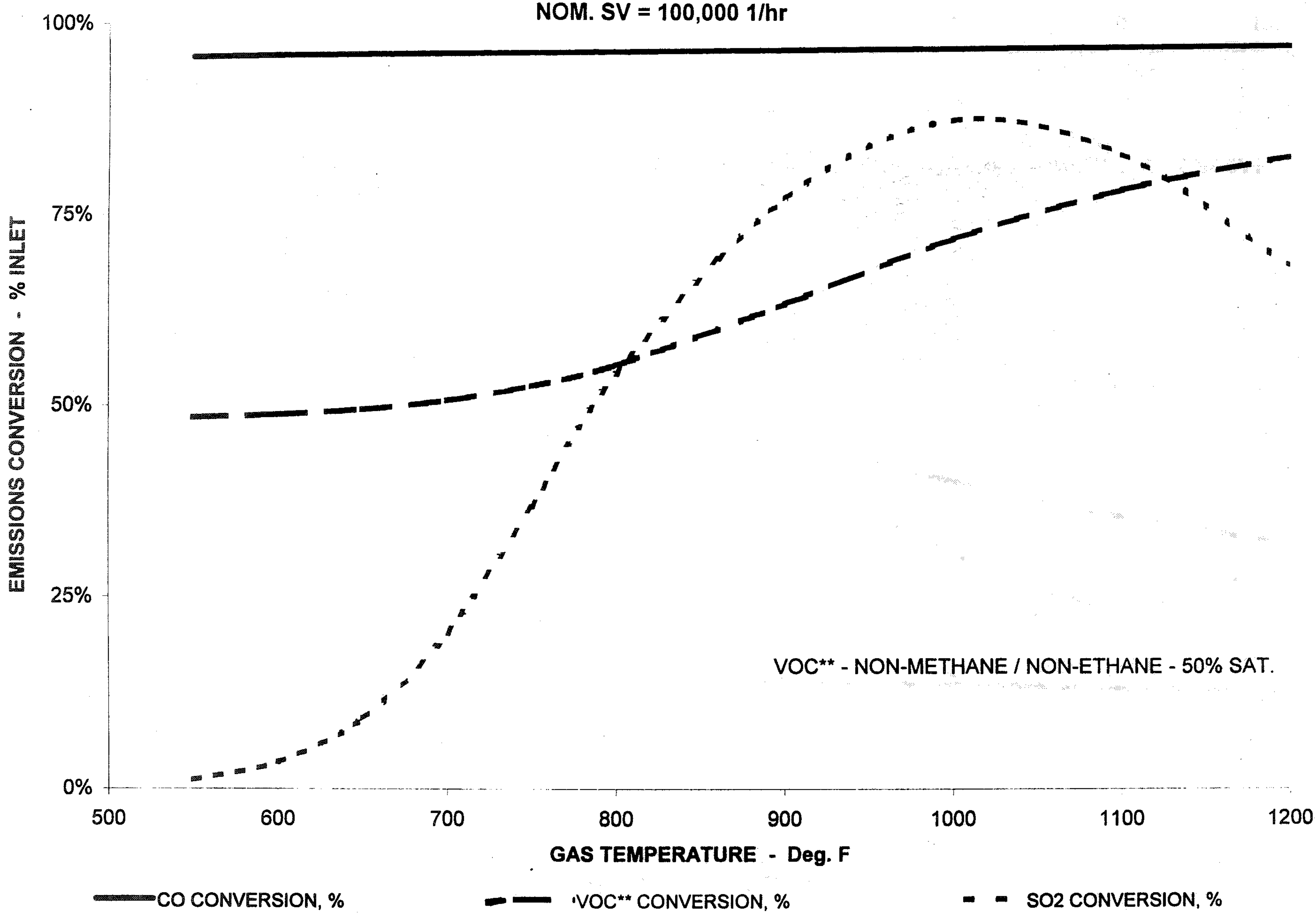
ENGELHARD


CAMET OXIDATION CATALYST
TYPICAL PERFORMANCE
NOM. SV = 200,000 1/hr
100%
75%
50%
25%
0%
EMISSIONS CONVERSIONS - %
500
600
700
800
900
1000
1100
1200
GAS TEMPERATURE - Deg. F
VOC** - NON-METHANE / NON-ETHANE - 50% SAT.
CO CONVERSION, %
VOC** CONVERSION, %
SO2 CONVERSION, %

ENGELHARD

CAMET OXIDATION CATALYST
TYPICAL PERFORMANCE
NOM. SV = 100,000 1/hr



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EMISSION TEST REPORT

for
EMISSIONS COMPLIANCE
of
TWO GENERAL ELECTRIC FRAME 7EA TURBINES
at the
FRONTERA GENERATION FACILITY
in
HIDALGO COUNTY, MISSION, TEXAS

Prepared for
DUKE FLUOR DANIEL

Test Date: March – May, 2000
Cubix Job No. 5664

Prepared by

Cubix Corporation
http://www.cubixcorp.com

CORPORATE HEADQUARTERS
9225 US Hwy. 183 South, Austin, TX 78747
(512) 243-0202 TEL (512) 243-0222 FAX

TABLE 3
UNIT 1: EXECUTIVE SUMMARY

Operator/Plant: Frontera Generation Facility
Location: Mission, TX
Source: Unit 1 Frame 7 GE Turbine
Technicians: AM, NSW, JM, TR, NS

Parameter	Allowable Emissions	Average Measured Emissions							
MEASURED EMISSIONS	TNRCC #37613/ PSD-TX-900	LOW LOAD	% of Allowable	LOW-INTERMEDIATE LOAD	% of Allowable	INTERMEDIATE LOAD	% of Allowable	BASE LOAD	% of Allowable
NOx ppmvd @ 15% O2	15	6.69	44.6	7.14	47.6	9.85	65.6	10.54	70.2
NOx lbs/hr	106.1	25.59	24.1	34.57	32.6	48.65	45.9	59.12	55.7
NOx lbs/MMBTU		0.024	NA	0.026	NA	0.036	NA	0.039	NA
CO ppmvd @ 15% O2	15	0.80	5.3	1.01	6.7	1.10	7.3	0.97	6.5
CO lbs/hr	51.5	1.87	3.6	2.98	5.8	3.29	6.4	3.32	6.4
CO lbs/MMBTU		0.0018	NA	0.0023	NA	0.0024	NA	0.0022	NA
PM lbs/hr	20.5	NA	NA	NA	NA	NA	NA	11.91	58.1
PM lbs/MMBTU		NA	NA	NA	NA	NA	NA	0.0077	NA
VOC lbs/hr	0.6	0.002	0.3	0.000	0.0	0.001	0.2	0.001	0.1
VOC lbs/MMBTU		0.000	NA	0.000	NA	0.000	NA	0.000	NA
SO2 lbs/hr	24.6	0.12	0.5	0.15	0.6	0.15	0.6	0.18	0.7
SO2 lbs/MMBTU		0.00	NA	0.00	NA	0.00	NA	0.00	NA
H2SO4 lbs/hr		NA	NA	NA	NA	NA	NA	0.2748	NA
H2SO4 lbs/MMBTU		NA	NA	NA	NA	NA	NA	0.0002	NA
Opacity		NA	NA	NA	NA	NA	NA	0	0

* NA-Not Applicable

TABLE 4
UNIT 2: EXECUTIVE SUMMARY

Operator/Plant: Frontera Generation Facility
Location: Mission, TX
Source: Unit 2 Frame 7 GE Turbine
Technicians: AM, NSW, JM, TR, NS

Parameter	Allowable Emissions	Average Measured Emissions							
MEASURED EMISSIONS	TNRCC #37613/ PSD-TX-900	LOW LOAD	% of Allowable	LOW-INTERMEDIATE LOAD	% of Allowable	INTERMEDIATE LOAD	% of Allowable	BASE LOAD	% of Allowable
NOx ppmvd @ 15% O2	15	5.26	35.1	5.50	36.7	6.12	40.9	10.05	67.0
NOx lbs/hr	106.1	20.6	19.4	26.7	25.2	33.0	31.1	56.9	53.6
NOx lbs/MMBTU		0.019	NA	0.020	NA	0.022	NA	0.037	NA
CO ppmvd @ 15% O2	15	0.31	2.0	0.98	6.5	1.04	6.9	0.92	6.1
CO lbs/hr	51.5	0.73	1.4	2.90	5.6	3.40	6.6	3.16	6.1
CO lbs/MMBTU		0.0007	NA	0.0022	NA	0.0023	NA	0.0020	NA
PM/PM10 lbs/hr	20.5	NA	NA	NA	NA	NA	NA	13.55	58.1
PM/PM10 lbs/MMBTU		NA	NA	NA	NA	NA	NA	0.0088	NA
VOC lbs/hr	0.6	0.000	0.00	0.001	0.00	0.001	0.17	0.005	0.01
VOC lbs/MMBTU		0.000	NA	0.000	NA	0.000	NA	0.000	NA
SO2 lbs/hr	24.6	0.09	0.00	0.11	0.00	0.13	0.01	0.32	1.30
SO2 lbs/MMBTU		0.00	NA	0.00	NA	0.00	NA	0.00	NA
H2SO4 lbs/hr		NA	NA	NA	NA	NA	NA	<0.1008	NA
H2SO4 lbs/MMBTU		NA	NA	NA	NA	NA	NA	0.0001	NA
Opacity		NA	NA	NA	NA	NA	NA	0	0

* NA-Not Applicable

Testing by Cubix Corporation, Austin, Texas

TABLE 5
UNIT 1: SUMMARY OF RESULTS

UNIT 1: SUMMARY OF RESULTS

Operator/Plant	Duke/Fluor Daniel Frontera Cogeneration Plant
Location	Mission, TX
Source	Unit #1 : Frame 7 GE Turbine w DLN
Technicians	AM, NSW, JM, TR, NS

[illegible]												
Test Run No.	T-1-1	T-1-2	T-1-3	T-1-4	T-1-5	T-1-6	T-1-7	T-1-8	T-1-9	T-1-10	T-1-11	T-1-12
Date	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/6/2000	5/7/2000	5/7/2000
Start Time	10:04	10:46	11:30	14:23	15:07	15:49	16:49	17:30	18:10	20:30	13:33	16:29
Stop Time	10:34	11:16	12:00	14:53	15:37	16:19	17:19	18:00	18:40	21:30	14:33	17:29
[illegible]												
Turbine Exhaust Temperature (F)	1197	1197	1198	1148	1149	1148	1124	1123	1122	1127	1137	1136
Turbine Fuel Flow Rate (lbs/sec)	12.49	12.37	12.31	15.68	15.59	15.75	13.07	17.40	17.47	18.57	18.14	18.08
Turbine Fuel Heating Value (BTU/lb)	23448	23448	23448	23448	23448	23448	23448	23448	23448	23448	23280	23280
Turbine Firing Rate (MMBTU/hr)	1054.0	1044.2	1039.3	1323.9	1316.3	1329.8	1102.8	1469.1	1474.3	1567.1	1520.3	1515.2
Compressor Inlet Temperature (°F)	100.0	101.5	103.5	89.0	89.0	89.0	88.0	88.0	87.0	82.0	89.0	88.0
Generator Output (MW)	74.6	75.1	75.3	121.1	119.6	120.3	138.4	139.2	139.4	149.5	144.0	144.2
Turbine Compressor Discharge Pressure (psig)	122	123	124	162	161	162	183	183	183	191	187	186
[illegible]												
Atmospheric Pressure (in. Hg)	29.81	29.80	29.79	29.75	29.73	29.71	29.71	29.71	29.71	29.78	29.78	29.75
Temperature (°F): Dry bulb	87	90	92	94	97	100	96	96	94	85	94	95
(°F) Wet bulb	77	79	80	81	80	80	74	74	73	74	78	77
Humidity (lb/lb air)	0.0173	0.0184	0.0188	0.0193	0.0177	0.0170	0.0126	0.0126	0.0123	0.0152	0.0165	0.0154
[illegible]												
NOx (ppmvd)	7.57	7.81	7.75	8.08	8.44	8.69	11.24	11.56	11.54	12.64	12.6	12.7
NOx (ppmvd @ 15% O2)	6.57	6.78	6.73	6.84	7.19	7.41	9.62	9.96	9.95	10.62	10.10	10.88
CO (ppmvd)	0.94	0.95	0.89	1.22	1.15	1.20	1.31	1.26	1.26	1.09	1.14	1.27
CO (ppmvd @ 15% O2)	0.82	0.82	0.77	1.03	0.98	1.02	1.12	1.09	1.09	0.92	0.91	1.09
O2 (vol%, dry)	14.10	14.10	14.11	13.93	13.97	13.98	14.01	14.05	14.06	13.88	13.53	14.01
CO2 (vol %, dry)	3.98	3.95	3.92	3.99	3.95	3.94	3.94	3.93	3.91	4.00	4.10	3.90
THC (ppmvw)	0.10	0.05	0.11	0.00	<0.01	<0.01	<0.01	0.05	0.06	<0.01	<0.01	<0.1
Dry Gas Fraction	0.91	0.91	0.91	0.91	0.91	0.91	0.92	0.92	0.92	0.92	0.92	0.92
THC (ppmvd)	0.11	0.05	0.12	0.00	<0.01	<0.01	<0.01	0.05	0.07	<0.01	0.01	0.05
VOC Portion of THC per fuel analysis (%)	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.64	1.54	1.54
VOC (ppmvd)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fuel Sulfur (ppmw)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4
SO2 (ppmv @ 15% O2)	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.022	0.024	0.024
H2SO4 (ppmvd)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<.01000	.06546	<.01000
PM-EPA front half only (lbs/DSCF)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	3.11E-07	1.06E-07	6.87E-08
PM-TNRCC front plus back half (lbs/DSCF)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	4.42E-07	2.64E-07	2.03E-07
Stack Flow Rate via O2 F-factor (SCFH, dry)	2.80E+07	2.77E+07	2.76E+07	3.43E+07	3.43E+07	3.47E+07	2.89E+07	3.87E+07	3.89E+07	4.03E+07	3.73E+07	3.97E+07
[illegible]												
NOx (lbs/hr)	25.3	25.9	25.6	33.1	34.6	36.0	38.8	53.5	53.7	60.9	56.2	60.3
NOx (lbs/MMBTU)	0.024	0.025	0.025	0.025	0.026	0.027	0.035	0.036	0.036	0.039	0.037	0.040
CO (lbs/hr)	1.91	1.92	1.79	3.04	2.87	3.03	2.75	3.55	3.57	3.19	3.09	3.67
CO (lbs/MMBTU)	0.0018	0.0018	0.0017	0.0023	0.0022	0.0023	0.0025	0.0024	0.0024	0.0020	0.0020	0.0024
PM-EPA front half only (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	12.5454	3.9643	2.7299
PM-TNRCC front plus back half (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	17.8253	9.8396	8.0517
PM-TNRCC front plus back half (lbs/MMBTU)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0114	0.0065	0.0053
THC (lbs/hr as methane)	0.128	0.063	0.139	0.000	<0.016	<0.016	<0.013	0.088	0.106	<0.02	<0.017	<0.090
VOC (lbs/hr as methane)	0.002	0.001	0.002	0.000	<0.000	<0.000	<0.000	0.001	0.002	<0.000	<0.000	<0.001
VOC (lbs/MMBTU [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SO2 (lbs/hr)	0.12	0.12	0.12	0.15	0.15	0.15	0.12	0.16	0.16	0.17	0.18	0.18
SO2 (lbs/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
H2SO4 (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<0.1026	<0.6207	<0.1011
H2SO4 (lbs/MMBTU)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<0.0001	<0.0004	<0.0001
NOx (tons/year)	110.87	113.32	112.09	145.01	151.47	157.79	170.00	234.25	235.02	266.62	246.07	264.21
CO (tons/year)	8.38	8.39	7.83	13.32	12.56	13.26	12.06	15.54	15.62	13.99	13.53	16.07
PM-EPA front half only (tons/year)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	54.95	17.36	11.96
PM-TNRCC front plus back half (tons/year)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	78.07	43.10	35.27
THC as VOC (tons/year)	0.56	0.28	0.61	0.00	<0.07	<0.07	<0.06	0.38	0.46	0.07	0.07	0.39
VOC (tons/year)	0.01	0.00	0.01	0.00	<0.00	<0.00	<0.00	0.01	0.01	0.00	0.00	0.01
SO2 (tons/year)	0.5119	0.5071	0.5048	0.6430	0.6393	0.6458	0.5356	0.7135	0.7160	0.7611	0.8009	0.7982

Testing by Cubix Corporation, Austin, Texas

TABLE 6
UNIT 2: SUMMARY OF RESULTS

UNIT 2: SUMMARY OF RESULTS

Operator/Plant: Duke/Fluor Daniel Frontera Cogeneration Plant
Location: Mission, TX
Source: Unit #2 : Frame 7 GE Turbine w DLN
Date: 03/08/00

Test Run No.	T-2-1	T-2-2	T-2-3	T-2-4	T-2-5	T-2-6	T-2-7	T-2-8	T-2-9	T-2-10	T-2-11	T-2-12
Date	3/2/2000	3/2/2000	3/2/2000	3/3/2000	3/3/2000	3/3/2000	3/3/2000	3/3/2000	3/3/2000	5/8/2000	5/8/2000	5/8/2000
Start Time	18:38	19:24	20:13	05:42	06:26	07:05	07:49	08:32	09:04	13:14	17:06	20:15
Stop Time	19:08	19:54	20:43	06:12	06:56	07:35	08:19	09:02	09:34	14:14	18:06	21:15
Operational Data												
Turbine Exhaust Temperature (F)	1176	1176	1176	1115	1117	1115	1093	1093	1092	1137	1137	1137
Turbine Fuel Flow Rate (lbs/sec)	12.78	12.64	12.71	15.56	15.88	15.81	17.38	17.46	17.67	18.30	18.48	18.69
Turbine Fuel Heating Value (BTU/lb)	23302	23302	23302	23414	23414	23414	23414	23414	23414	23259	23259	23259
Turbine Firing Rate (MMBTU/hr)	1072.1	1060.3	1066.2	1311.6	1338.5	1332.6	1465.0	1471.7	1489.4	1532.3	1547.4	1564.9
Generator Output (MW)	81.2	80.1	79.7	127.7	128.9	128.8	144.4	145.2	145.4	144.9	145.2	144.9
Turbine Compressor Discharge Pressure (psig)	129	128	128	168	169	168	187	188	189	188	188	188
Ambient Conditions												
Atmospheric Pressure (in. Hg)	29.82	29.82	29.82	29.72	29.72	29.78	29.80	29.82	29.84	29.66	29.75	29.78
Temperature (°F): Dry bulb	75	75	75	69	69	69	71	73	75	89	86	85
(°F) Wet bulb	68	68	68	67	67	67	67.5	68.5	69.5	71	73	74
Humidity (lb/lb air)	0.0128	0.0128	0.0128	0.0136	0.0136	0.0135	0.0134	0.0137	0.0139	0.0119	0.0141	0.0152
Measured Emissions												
NOx (ppmvd)	5.86	6.01	6.07	6.46	6.46	6.51	7.21	7.11	7.01	12.23	12.0	12.1
NOx (ppmvd @ 15% O2)	5.14	5.30	5.35	5.49	5.47	5.55	6.23	6.12	6.03	10.22	9.99	9.95
CO (ppmvd)	0.06	0.23	0.76	1.15	1.17	1.15	1.16	1.21	1.24	1.31	0.96	1.05
CO (ppmvd @ 15% O2)	0.05	0.20	0.67	0.98	0.99	0.98	1.00	1.04	1.07	1.09	0.80	0.86
O2 (vol%, dry)	14.17	14.21	14.21	13.96	13.93	13.98	14.07	14.04	14.04	13.84	13.79	13.70
CO2 (vol %, dry)	3.83	3.85	3.86	3.90	3.89	3.90	3.88	3.85	3.88	4.10	4.10	4.10
THC (ppmvw)	0.00	0.03	0.00	0.08	0.05	0.03	0.03	0.04	0.04	0.39	0.09	0.05
Dry Gas Fraction	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.91	0.90	0.91
THC (ppmvd)	0.00	0.03	0.00	0.09	0.05	0.03	0.03	0.04	0.04	0.43	0.10	0.06
VOC Portion of THC per fuel analysis (%)	2.29	2.29	2.29	1.37	1.37	1.37	1.37	1.37	1.37	1.56	1.56	1.56
VOC (ppmvd)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Total Fuel Sulfur (ppmw)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	2.4	2.4	2.4
SO2 (ppmv @ 15% O2)	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.041	0.041	0.041
H2SO4 (ppmvd)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<.01000	<.01000	<.01027
PM-EPA front half only (lbs/DSCF)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	2.36E-07	1.68E-07	1.36E-07
PM-TNRCC front plus back half (lbs/DSCF)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	4.16E-07	3.93E-07	2.26E-07
Stack Flow Rate via O2 F-factor (SCFH, dry)	2.88E+07	2.87E+07	2.88E+07	3.41E+07	3.47E+07	3.48E+07	3.87E+07	3.87E+07	3.92E+07	3.92E+07	3.93E+07	3.93E+07
Calculated Emission Rates												
NOx (lbs/hr)	20.2	20.6	20.9	26.3	26.8	27.1	33.4	32.9	32.8	57.3	56.6	56.9
NOx (lbs/MMBTU)	0.019	0.019	0.020	0.020	0.020	0.020	0.023	0.022	0.022	0.037	0.037	0.036
CO (lbs/hr)	0.13	0.48	1.59	2.85	2.95	2.91	3.27	3.41	3.54	3.73	2.74	3.00
CO (lbs/MMBTU)	0.0001	0.0005	0.0015	0.0022	0.0022	0.0022	0.0022	0.0023	0.0024	0.0024	0.0018	0.0019
PM-EPA front half only (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	9.2635	6.6099	5.3577
PM-TNRCC front plus back half (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	16.3236	15.4405	8.8734
PM-TNRCC front plus back half (lbs/MMBTU)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	0.0107	0.0100	0.0057
THC (lbs/hr as methane)	0.000	0.039	0.000	0.124	0.079	0.047	0.053	0.070	0.071	0.70	0.16	0.09
VOC (lbs/hr as methane)	0.000	0.001	0.000	0.002	0.001	0.001	0.001	0.001	0.001	0.011	0.003	0.001
VOC (lbs/MMBTU as methane)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SO2 (lbs/hr)	0.0920	0.0910	0.0915	0.1120	0.1143	0.1138	0.1251	0.1257	0.1272	0.3162	0.3193	0.3230
SO2 (lbs/MMBTU)	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002
H2SO4 (lbs/hr)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<0.0998	<0.1000	<0.1026
H2SO4 (lbs/MMBTU)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	<0.0001	<0.0001	<0.0001
NOx (tons/year)	88.34	90.15	91.55	115.38	117.25	118.48	146.15	144.16	143.84	251	248	249
CO (tons/year)	0.55	2.10	6.98	12.50	12.92	12.74	14.31	14.93	15.48	16.36	12.02	13.13
PM-EPA front half only (tons/year)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	40.57	28.95	23.47
PM-TNRCC front plus back half (tons/year)	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	71.50	67.63	38.87
THC as VOC (tons/year)	0.00	0.17	0.00	0.54	0.34	0.21	0.23	0.31	0.31	3.07	0.72	0.39
VOC (tons/year)	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.05	0.01	0.01
SO2 (tons/year)	0.4030	0.3986	0.4008	0.4907	0.5008	0.4986	0.5481	0.5506	0.5572	1.3851	1.3987	1.4146

Testing by Cubix Corporation, Austin, Texas

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EXHIBIT

INTC-

HN 0403K

EMISSION TEST REPORT

for

INITIAL COMPLIANCE TESTS

of

ONE GENERAL ELECTRIC FRAME 7FA TURBINE (Unit 2)

at the

FRONTERA GENERATION FACILITY

in

HIDALGO COUNTY, MISSION, TEXAS

Prepared for
DUKE FLUOR DANIEL

Test Date: July, 1999

Cubix Job No. 5444

RECEIVED
AUG 30 1999
PERMITS PROGRAM

Prepared by

Cubix Corporation

CORPORATE HEADQUARTERS
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INTRODUCTION

Emission tests were conducted on a simple cycle gas turbine generation unit (Unit #2) located at the Frontera Generation Facility in Mission, Texas. The purpose of these tests was to determine the compliance status of the unit with regard to TNRCC Permit Numbers 37613/PSD-TX-900 and 40 CFR 60, Subpart GG. The testing was conducted by Cubix Corporation of Austin, Texas on July 15-16, 1999.

Quantities of nitrogen oxides (NOx), carbon monoxide (CO), particulate matter (PM), SO_2, and VOC were measured in the exhaust of the turbine.

The emission tests followed the procedures set forth in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 2, 3a, 4, 5, 9, 10, 19, 20 and 25a. Table 1 summarizes the background information pertinent to these tests.

This report has been reviewed and approved for submittal by the following representatives:

Cubix Corporation	Duke/Fluor Daniel

TABLE 1
BACKGROUND DATA

Construction:	Duke Fluor Daniel 2300 Yorkmont Charlotte, NC 28217 Attn: Tom Griffin (965) 519-4239 TEL (965) 519-1322 FAX
Owner/Operator:	Frontera Generation Limited Partnership 1616 Woodall Rogers Freeway Dallas, Texas 75202 Attn: Patrick Blanchard (214) 342-2154 TEL (214) 342-2198 FAX
Test Contractor:	Cubix Corporation 9225 Lockhart Highway Austin, Texas 78747 Attn.: Rick J. Krenzke (512) 243-0202 TEL (512) 243-0222 FAX
Test Dates:	July 15-16, 1999
Location:	Mission, Texas
Process Description:	The turbine is utilized for generation of electricity. Dry-low burners are utilized for NOx control.
Emission Point:	Emissions were measured in the temporary simple cycle exhaust stack on Unit #2.

Test Methods:	Traverse point layout by EPA Method 1
	Pitot tube traverse by EPA Method 2
	O_2 and CO_2 concentrations and molecular weight by EPA Method 3a
	Stack moisture content by EPA Method 4, also by stoichiometric calculation
	PM measurements by EPA Method 5 with TNRCC back-half analysis convention
	Opacity by EPA Method 9
	CO concentration by EPA Method 10
	Stack flow rates by EPA Method 19
	NOx and O2 by EPA Method 20
	THC concentration by EPA Method 25a VOC from THC results and fuel composition
	ASTM 3246 for fuel sulfur content
Regulatory Applications:	TNRCC Permit No. 37613/PSD-TX-900 40 CFR 60 Subpart GG

SUMMARY OF RESULTS

Exhaust gases from the Unit 2 gas turbine generation unit were tested to satisfy permit requirements. The testing was conducted July 15-16, 1999 by Cubix Corporation of Austin, Texas. The results of those tests are summarized in this section of the report.

Test Matrix

The test matrix utilized to satisfy the turbine emission test requirements is shown in Table 2. The test matrix consisted of an initial O_2 traverse (at the lowest load condition) and three test runs at each of four separate load conditions ranging from minimum to base load. These loads represent the operational range of the unit.

The O_2 traverse consisted of measuring O_2 concentrations at 48 traverse points within the exhaust stack while the unit was operating at minimum load. All subsequent testing was conducted at the eight points of lowest O_2 concentration as found during the O_2 traverse. No stratification was found so eight points were selected at random. During the 32-minute test runs conducted at reduced loads and the 1-hour test runs conducted at base load, NOx, CO, VOC, CO_2, and O_2 concentrations were continuously monitored via instrumental analysis. In addition, PM and opacity were measured at base load condition. Duke Fluor Daniel personnel collected fuel samples which were subsequently analyzed for composition and for total sulfur content as an indirect measurement of SO_2 emissions.

Table 3 and Table 4 provide the results of the testing for Unit 2. Table 3 provides an Executive Summary presenting the average test run results and comparing the test results to the permitted emissions limits. Table 4 provides the pertinent unit operational data, ambient conditions, Cubix emission measurements, and calculated mass emissions during each test run.

The data used to generate these tables are supported by the documents presented in the appendices of this report. See "Table of Contents" for the list of appendices.

Table 2 : Compliance Test Matrix

Operator/Plant: **Frontera Generation Facility**
Location: Mission, TX
Source: Unit 2 : GE Frame 7 Turbine
Technicians: RK, DV, TR, JJ, JC

Item	Method
SO2	ASTM 3246 (based on fuel flow and Fuel sulfur)
CO2/O2	EPA Method 3a
CO	EPA Method 10
NOx/O2	EPA Method 20
VOC	EPA Method 25a (VOC fraction of fuel analysis)
PM/PM10	EPA Method 1-5 including TNRCC back-half analysis
Opacity	EPA Method 9
Volumetric flow	EPA Method 19

Gas turbine load	≈71%	≈81%	≈90%	Base	Base	Base
Number of runs	3	3	3	3	3	30
Duration of runs	32 minutes	32 minutes	32 minutes	60 minutes	132 minutes	6 minute
Air contaminants						
O2	X	X	X	X		
NOx	X	X	X	X		
CO	X	X	X	X		
VOC	X	X	X	X		
CO2	X	X	X	X		
PM/PM10					X	
Opacity						X

TABLE 3
EXECUTIVE SUMMARY

TABLE 3 :
EXECUTIVE SUMMARY

Operator/Plant: Duke/Fluor Daniel/Frontera Generation Facility
Location: Mission, TX
Source: Unit 2 : GE Frame 7 Turbine
Technicians: TR, AM, JR, SW, AF, KH

Parameter	Allowable Emissions		Average Measured Emissions							
			Low Load		Low-Inter. Load		Intermediate Load		Base Load	
MEASURED EMISSIONS	TNRCC #37613 PSD-TX-900	40 CFR 60, SUBPART GG	Avg. Result	% of Allowable	Avg. Result	% of Allowable	Avg. Result	% of Allowable	Avg. Result	% of Allowable
NOx ppmvd @ 15% O2	15.0		5.5	36.67%	7.1	47.33%	8.4	56.00%	11.0	73.33%
NOx ppmvd @ 15% O2 ISO		75	6.5	8.67%	8.4	11.20%	9.7	12.93%	12.7	16.93%
NOx lbs/hr	106.1		22.0	20.74%	30.7	28.93%	39.7	37.42%	57.0	53.72%
CO ppmvd @ 15% O2	15.0		0.3	2.00%	0.4	2.67%	0.4	2.67%	0.4	2.67%
CO lbs/hr	51.5		0.8	1.55%	1.0	1.94%	1.3	2.52%	1.3	2.52%
PM/PM10 lbs/hr	20.5		NA	NA	NA	NA	NA	NA	18.95	92.44%
VOC lbs/hr	0.6		NA	NA	NA	NA	NA	NA	0.013	1.33%
SO2 lbs/hr	24.6		NA	NA	NA	NA	NA	NA	0.1556	0.63%
Opacity	5		NA	NA	NA	NA	NA	NA	0	0.00%

* NA-Not Applicable

Table 4
Turbine #2 : Summary of Results

Plant/Location: Duke/Fluor Daniel/ Frontera Cogeneration Facility
Emission Source: GE Frame 7FA Turbine
Technicians: RK, DV, TR, JJ, JC
Turbine: GE Frame 7 - Unit #2

Test Run	C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	C-10	C-11	C-12
Date	7/15/99	7/15/99	7/15/99	7/15/99	7/15/99	7/15/99	7/15/99	7/15/99	7/15/99	7/16/99	7/16/99	7/16/99
Start Time	6:32	11:20	16:00	19:48	20:36	21:26	22:19	23:09	23:58	0:47	1:34	2:21
Stop Time	7:32	12:20	17:00	20:20	21:08	21:58	22:51	23:41	0:30	1:19	2:06	2:53
Unit Operation		Base Load			Intermediate Load			Low-Intermediate Load			Minimum Load	
~ Percentage of Base Load		100%			~90%			~80%			~71%	
Generator Power output (MW)	162.80	161.20	160.90	147.10	145.90	146.00	128.90	129.10	130.50	115.10	115.00	114.90
Turbine Exhaust Temperature (°F)	1116	1121	1121	1123	1124	1124	1144	1142	1141	1155	1155	1155
Inlet Guide Vane Angle (degrees)	90.0	90.0	90.0	84.1	81.4	80.3	66.2	66.1	66.5	59.5	59.3	59.2
Compressor Discharge Pressure (psi)	198.10	196.40	195.40	184.50	182.20	181.90	163.60	163.40	165.10	151.40	151.70	150.60
Compressor Inlet Air Temperature (°F)	72	76	78	89	87	85	84	81	81	80	80	79
Specific Humidity (CMHUM-lb/lb)	0.0023	0.0022	0.0020	0.0022	0.0022	0.0023	0.0023	0.0023	0.0024	0.0025	0.0024	0.0025
Fuel Data Natural Gas												
Turbine Fuel Flow (lb/sec) from Mark V Controller	17.11	16.95	17.06	15.74	15.65	15.70	14.25	14.20	14.34	13.34	13.25	13.20
Turbine Fuel Heating Value (BTU/lb - HHV)	23015	23015	23015	23015	23015	23015	23015	23015	23015	23015	23015	23015
Fuel Specific Gravity	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877	0.57877
Turbine Firing Rate (MMBTU/hr)	1417.63	1404.38	1413.49	1304.12	1296.67	1300.81	1180.67	1176.53	1188.13	1105.27	1097.82	1093.67
Fuel O2 F Factor (DSCF/MMBTU @ EPA STP)	8635	8635	8635	8635	8635	8635	8635	8635	8635	8635	8635	8635
Total Fuel Sulfur (Avg. ppmw from fuel analyses)	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
VOC Fraction (%) from Fuel Analysis	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54	0.54
Stack Moisture (% by Vol. via stoichiometry)	9.29	9.64	9.55	9.38	9.56	9.45	9.61	9.61	9.58	9.60	9.63	9.68
Ambient Conditions												
Temperature (°F wet)	73	79	80	78	78	77	77	77	77	77	77	77
Temperature (°F dry)	74	90	97	87	86	85	83	82	81	82	81	81
Altitude (ft)	100	70	130	140	120	90	80	60	65	65	60	60
Barometer (in. Hg)	29.80	29.83	29.76	29.75	29.77	29.81	29.82	29.84	29.83	29.83	29.84	29.84
Humidity (lbs/lb of air)	0.0169	0.0183	0.0177	0.0182	0.0184	0.0177	0.0182	0.0184	0.0187	0.0184	0.0186	0.0186
Stack Flow Rates (F-Factors & PM/H2SO4 Train)												
O2 Stoichiometry (DSCFH)	3.52E+07	3.42E+07	3.44E+07	3.30E+07	3.21E+07	3.22E+07	2.88E+07	2.89E+07	2.95E+07	2.72E+07	2.70E+07	2.67E+07
Pitot Tube (DSCFH from PM Train)	4.59E+07	4.51E+07	4.49E+07	NA	NA	NA	NA	NA	NA	NA	NA	NA
Pitot Tube (DSCFH from H2SO4 Train)	4.30E+07	4.35E+07	4.53E+07	NA	NA	NA	NA	NA	NA	NA	NA	NA
Stack Concentrations												
NOx (ppmv) 6C-1 corrected	14.2	14.0	13.1	10.5	10.2	10.0	8.9	8.7	8.9	7.0	6.8	6.7
NOx (ppmv @ 15% O2)	11.5	11.2	10.4	8.7	8.3	8.1	7.1	7.0	7.2	5.6	5.5	5.4
NOx (ppmv @ 15% O2 @ ISO day conditions)	13.5	12.9	11.6	10.1	9.6	9.3	8.3	8.2	8.6	6.6	6.5	6.4
CO (ppmv) 6C-1 corrected	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.4	0.4	0.4	0.4
CO (ppmv @ 15% O2)	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.3	0.3	0.3	0.3
O2 (%) 6C-1 corrected	13.64	13.50	13.48	13.77	13.61	13.61	13.51	13.55	13.63	13.56	13.57	13.52
CO2 (%) 6C-1 corrected	4.04	4.02	4.00	3.86	3.94	3.96	3.97	4.05	3.98	3.97	3.99	4.00
THC (ppmvw as methane) 6C-1 corrected	0.90	0.90	1.10	1.20	0.70	0.70	0.80	1.00	0.60	0.70	0.00	0.20
THC (ppmvd as methane) 6C-1 corrected	0.99	1.00	1.22	1.32	0.77	0.77	0.89	1.11	0.66	0.77	0.00	0.22
VOC (ppmvd as methane) based on % VOC fuel analysis	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
SO2 (ppmv @ 15% O2) based on fuel sulfur analysis	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
H2SO4 (ppmvd)	0.04	0.08	0.07	NA	NA	NA	NA	NA	NA	NA	NA	NA
PM/PM10-EPA front half (lbs/DSCF)	2.60E-07	3.85E-07	2.84E-07	NA	NA	NA	NA	NA	NA	NA	NA	NA
PM/PM10-TNRCC front + back half (lbs/DSCF)	3.17E-07	6.48E-07	2.91E-07	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mass Emissions from O2 "F" Factor												
NOx (lbs/hr)	59.8	57.3	53.8	41.4	39.1	38.5	30.7	30.0	31.4	22.7	22.0	21.4
NOx (lbs/MMBTU)	0.042	0.041	0.038	0.032	0.030	0.030	0.026	0.026	0.026	0.021	0.020	0.020
NOx (tons/yr)	261.831	250.891	235.649	181.352	171.319	168.496	134.270	131.504	137.348	99.535	96.170	93.759
CO (lbs/hr)	1.5	1.2	1.2	1.2	1.2	1.4	1.0	1.0	0.9	0.8	0.8	0.8
CO (lbs/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO (tons/yr)	6.7	5.4	5.5	5.3	5.1	6.1	4.6	4.6	3.8	3.5	3.4	3.4
VOC (lbs/hr)	0.008	0.008	0.009	0.010	0.006	0.006	0.006	0.007	0.004	0.005	0.000	0.001
VOC (lbs/MMBTU)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
VOC (tons/yr)	0.034	0.034	0.041	0.043	0.024	0.024	0.025	0.031	0.019	0.021	0.000	0.006
PM/PM10-EPA front half (lbs/hr)	11.93	17.38	12.72	NA	NA	NA	NA	NA	NA	NA	NA	NA
PM/PM10-EPA front half (tons/yr)	52.27	76.14	55.71	NA	NA	NA	NA	NA	NA	NA	NA	NA
PM/PM10-TNRCC front + back half (lbs/hr)	14.55	29.23	13.07	NA	NA	NA	NA	NA	NA	NA	NA	NA
PM/PM10-TNRCC front + back half (tons/yr)	63.74	128.03	57.24	NA	NA	NA	NA	NA	NA	NA	NA	NA
SO2 (lbs/hr)	0.1355	0.1342	0.1351	0.1247	0.1239	0.1243	0.1129	0.1125	0.1136	0.1057	0.1049	0.1045
SO2 (tons/yr)	0.5935	0.5880	0.5918	0.5460	0.5429	0.5446	0.4943	0.4926	0.4974	0.4628	0.4596	0.4579

PROCESS DESCRIPTION

Frontera Generation Limited Partnership is the owner and operator of the Frontera Generation Facility. This facility is currently under construction by Duke Fluor Daniel in Mission, Texas. Emission testing was conducted on one of two turbines in operation at that facility (Unit #2). This section of the test report provides a brief description of those units.

Upon completion, the facility will utilize two identical units to provide electricity to the local power grid and provide steam to power a steam generator. The turbines are General Electric Frame 7FA units. The rated capacity of each turbine is 1866 MMBTU/hr at base load. Dry-low burners are utilized for NOx control. The boilers are currently under construction and were not in service during these tests. The turbines are fired exclusively on pipeline quality natural gas.

Each unit's exhaust is vented to the atmosphere through an 18 ft diameter stack approximately 120 ft above grade. Four sample ports meeting EPA criteria are provided at the 100 ft level. These stacks are not permanent and will eventually be placed after the boiler section of the unit (currently under construction). The boiler is not supplementally fired, so emissions will not be effected after the boiler is completed and the stack is moved to its final location.

ANALYTICAL TECHNIQUE

The sampling and analysis procedures used during these tests conformed in principle with those outlined in the Code of Federal Regulations, Title 40, Part 60, Appendix A, Methods 1, 2 , 3a, 4, 5, 9, 10, 19, 20, and 25a and ASTM methodology for the fuel analyses. The test procedures are discussed below. The stack gas analyses for NO_x, CO, THC/VOC, CO_2, and O_2 were performed by continuous instrumental monitors. Table 5 lists the instruments and detection principles used for these analyses.

The test matrix for each unit consisted of an initial O_2 traverse followed by three test runs at each of four conditions. The initial O_2 traverse consisted of continuous O_2 measurements over a 96-minute period at each of 48 traverse points. The eight points of lowest O_2 concentration found during the initial O_2 traverse were utilized for all subsequent testing.

While operating at each of the reduced load conditions, the test matrix consisted of three 32-minute test runs (per Method 20 requirements of eight traverse points for 1-minute plus the average sample system response time) during which NOx, CO, THC/VOC, CO_2, and O_2 concentrations were continuously monitored via instrumental analysis. At base load, NOx, CO, THC/VOC, CO_2, and O_2 measurements were conducted throughout three 1-hour test runs.. Three 132-minute test runs for particulate matter were conducted during the base load tests. Thirty 6-minute opacity observations were also conducted while operating at base load. A fuel sample was collected and subsequently analyzed for composition and total sulfur content. Method 19 stoichiometric calculations were utilized for NOx, CO, and THC/VOC emission rates and Method 1-4 (via the isokinetic sample trains) were utilized for PM emission rates.

The sampling and analysis system used to determine exhaust emission concentrations of NOx, CO, O_2, CO_2, and THC/VOC is depicted in Figure 1. Stack gas entered the sample system through a heated stainless steel probe with a glass wool filter. The sample was transported via 3/8-inch heat-traced Teflon® tubing using a stainless steel/Teflon® diaphragm pump to the wet portion of the sample manifold. This feature is designed to ensure that no condensation of heavy hydrocarbons will occur during THC sampling. The sample was then delivered to a specially designed stainless steel minimum-contact condenser which dried the sample without removing the pollutants of interest before being passed back to the dry portion of the sample manifold. From the dry manifold, the sample was partitioned to the analyzers through glass and stainless steel rotameters that controlled the flow of the sample.

Figure 1 shows that the sampling system was equipped with a separate path through which a calibration gas could be delivered to the probe and back through the entire sampling system. This allowed for convenient performance of system bias checks and calibrations as required by the testing methods.

All instruments were housed in an air conditioned trailer-mounted mobile laboratory. Gaseous calibration standards were provided in aluminum cylinders with the concentrations certified by the vendor.

All data from the continuous monitoring instruments were recorded on two synchronized 3-pen strip chart recorders (Soltec Model 1243). These recorders were operated at a chart speed of 30 centimeters/hour and recorded over a 25-centimeter width. Strip chart records may be found in Appendix F of this report. A computer data logger was also utilized for convenient presentation of the emission concentrations. Computer data logs can be found in Appendix I.

EPA Method 1 was utilized for selection of the traverse points for the compliance testing. The stack configurations and sample port locations did meet EPA Method 1 criteria. Forty-eight traverse points were used for the initial O_2 traverse on each unit and twenty-four points for the PM testing.

EPA Method 2 was followed for determination of stack gas velocity and flow rate. An S-type pitot tube, on the head of the Method 5 sampling train where applicable, and inclined water manometer were used to determine the velocity head pressures at each traverse point. The stack gas temperature was determined with a K-type (chromel-alumel) thermocouple used in conjunction with a digital thermometer. This instrument also assisted in monitoring the sampling system conditions (impinger temperature, etc.)

During preliminary measurements (for selection of a nozzle size to maintain isokinetic sampling), cyclonic flow checks were conducted. This check was performed by using a protractor to determine the flow angle (greater than zero) at each traverse point. The average of these flow angles must be less than 20°. It was found that cyclonic flow did not exist.

The O_2 and CO_2 concentration measurements used in determination of stack gas molecular weight were measured in accordance with the procedures of EPA Method 3a. Instrumental analysis were used in lieu of the Orsat or Fyrite techniques. A paramagnetic O_2 analyzer and an infrared absorption CO_2 analyzer were utilized for these emission tests.

The moisture content of the stack gas was determined by the use of EPA Method 4 (via the Method 5 sample train). The impingers were weighed individually before and after each test run to gravimetrically determine the moisture content of the stack gas.

EPA Method 5 was used to determine the concentration of particulate matter being emitted from the turbine. Figure 2 shows that a gaseous sample was pulled through a stainless steel nozzle and heated glass probe to a heated glass fiber filter This portion of the sample train constitutes the "front half" assembly. The nozzle was sized such that an isokinetic sampling rate (i.e. sampling at the same rate as the stack velocity) could be maintained within the capabilities of the sample pump. Following the filter, the sample was pulled through an impinger train to a dry gas meter and sample pump. The back half of the filter holder and impingers constitute the "back half" assembly. The impingers were charge with deionized water. The PM emission rate results presented in this report provide both the EPA "front half" only analysis as well as TNRCC's "front plus back half" analysis convention.

The probe and nozzle were rinsed with acetone following each test run. These rinses were saved and analyzed for weight gain. The weight gain of the acetone rinse plus the weight gain of the filter constitute the front half PM analysis. The impinger contents from each test run were saved after weighing the impingers for moisture content. The solution from the impingers was combined with distilled water rinses of the impingers and back half of the filter holder boiling down and weighing at Cubix's Austin laboratory. The weight gain of these impinger boil downs constitutes the back half PM analyses.

All EPA Method 5 particulate matter weighings were conducted on a Mettler H6T balance. This balance has a 160 gram capacity and a 0.0001 g sensitivity. The balance was leveled and zeroed before each series of weighings. All weighings of filters and beakers were repeated until a "constant weight" was obtained. A "constant weight" is defined by EPA Method 5 as a difference of no more than 0.5 mg or 1 percent of the total weight less tare weight, whichever is greater. This definition applies to two consecutive weighings with no less than 6 hours of desiccation time between weighings. The sample recovery data sheets in Appendix A describe the weighing times and dates and the difference between weighings is recorded to establish that a constant weight had been obtained.

EPA Method 9 was utilized for opacity observations throughout thirty 6-minute readings. The opacity observer has been EPA certified per Method 9.

CO concentrations were quantified during the tests in accordance with procedures set forth in EPA Method 10. A continuous non-dispersive infrared (NDIR) analyzer was used for this purpose. This analyzer is equipped with a gas correlation filter which also removes any interference from CO_2 or other combustion products, eliminating the need for ascarite traps and the associated correction factors.

EPA Method 19 stoichiometric formulas were used for calculation of stack volumetric flow rates and mass emission rates of NOx, CO, and VOC. These calculations were based on the fuel analysis data, diluent O_2 measurements, and plant provided fuel flow rates. Method 19 stoichiometry was also utilized as a means to calculate the moisture content of the stack gas. Flow measurements obtained during particulate sampling by EPA Methods 1-4 were used to calculate the PM emission rate only.

Method 20 was used for measurement of NO_x and O_2 concentrations. A chemiluminescence cell analyzer was used for the NOx measurements and an electrochemical cell analyzer utilized for the O_2 measurements.

In addition to the instrument test method requirements (Methods 10 and 20). Method 6c quality assurance procedures were also utilized throughout the testing in any cases where the Method 6c criteria is more stringent that another method requirements. For example, all zero/span checks were conducted through the entire sample system which is not required by Methods 10 or 20. Additionally, Equation 6c-1 was used to correct all emission concentrations for zero and span drift.

VOC testing included measuring "total" hydrocarbons on a wet basis using a JUM flame ionization analyzer calibrated in accordance with EPA Method 25a. Per the discussions during the pre-test meeting, VOC emissions were determined based on THC measurements and the non-methane, non-ethane fraction of the fuel as found from the fuel analyses. Methane calibration standards were utilized for the tests and the emission concentrations are reported as methane equivalents and the mass emission rates were calculated using the molecular weight of methane.

Atmospheric pressure was measured at the test site using a certified aircraft-type aneroid altimeter. Ambient temperature and humidity were quantified during each test run via sling psychrometry.

Key operational data was provided by plant personnel. This data included turbine megawatts, fuel flow rates, and compressor discharge pressures. All plant provided operational data is contained in Appendix C.

Table 5 : Analytical Instrumentation

Parameter	Model and Manufacturer	Common Ranges	Sensitivity	Response Time	Detection Principle
NO_x	TECO 10AR	0-10 ppm 0-100 ppm 0-200 ppm 0-500 ppm 0-1,000 ppm 0-5,000 ppm	0.1 ppm	1.7 sec.	Thermal reduction of NO_2 to NO. Chemiluminescence reaction of NO with O_3. Detection by PMT. Inherently linear for listed ranges.
CO	TECO 48	0-10 ppm 0-20 ppm 0-50 ppm 0-100 ppm 0-200 ppm 0-500 ppm 0-1000 ppm	.1 ppm	10 sec.	Infrared absorption, gas filter correlation detector, microprocessor based linearization.
CO_2	Horiba Mexa 211GE	0-4 % 0-20 %	0.02%	30 sec	Infrared absorption, analog linearization.
O_2	Teledyne 320	0-5 % 0-10 % 0-25 %	0.10%	15 sec.	Electro-chemical cell, inherently linear.
THC	JUM Model 3-300	0-10, 0-100, 0-1K, 0-10K 0-100K ppm	0.2 ppm	5 sec.	Flame ionization of hydrocarbons inherently linear over 2 orders of magnitude.

NOTE: Higher ranges available by sample dilution
Other ranges available via signal attenuation.

FIGURE 1 : INSTRUMENTAL SAMPLING AND ANALYSIS SYSTEM

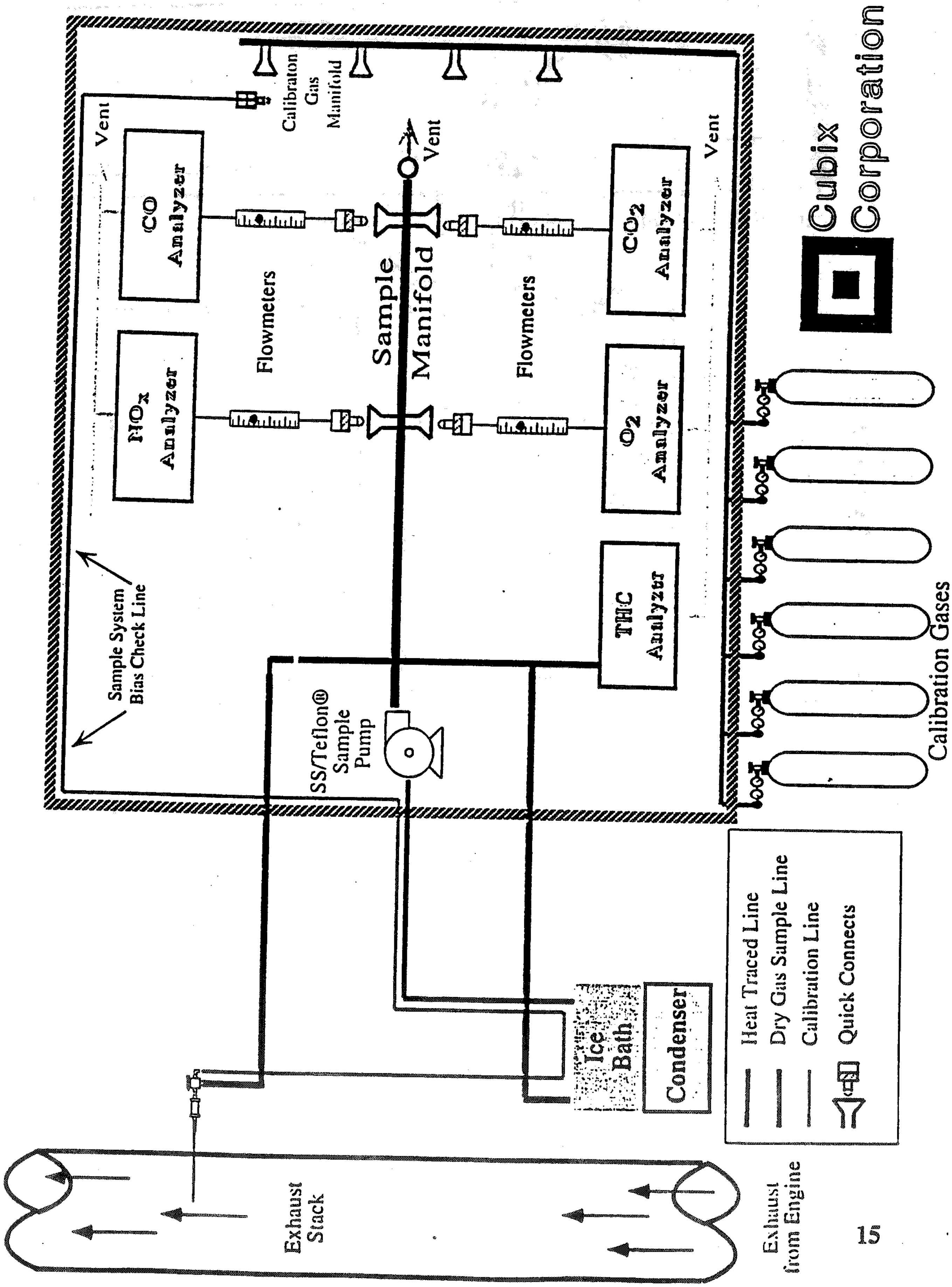
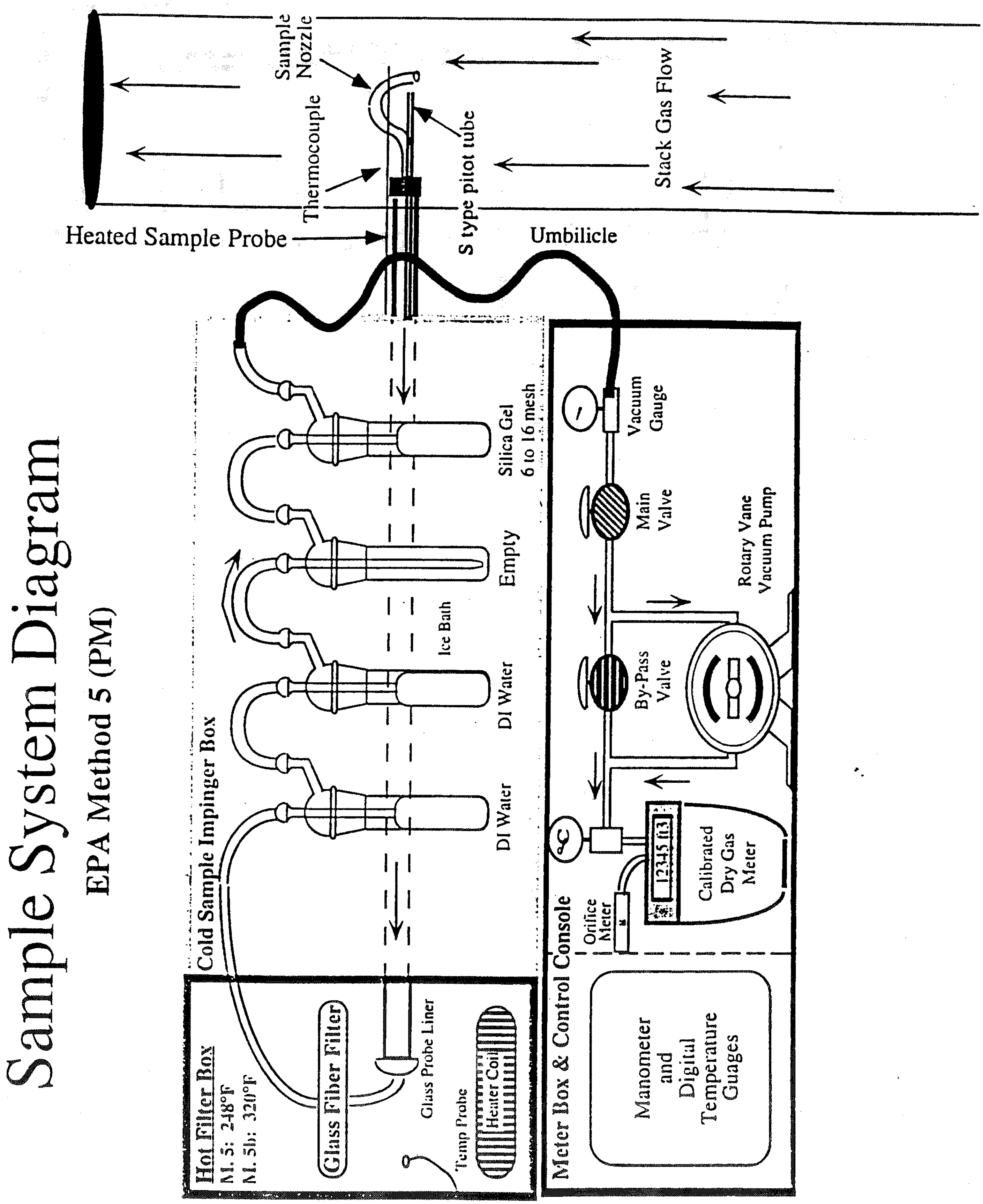


Figure 2 : Particulate Matter Sample System Diagram



QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities were undertaken before, during, and after this testing project to ensure the accuracy of results obtained. This section of the report and the documentation contained in Appendices D and E describe each quality assurance activity that was performed.

With the exception of the fuel and PM analyses, all sampling and analyses were conducted on-site to afford any interested parties the opportunity to observe all aspects of the test and to circumvent the possibility of sample loss or contamination during transport.

Each instrument's response was checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity was checked by first adjusting the zero and span responses to zero (nitrogen) and an upscale calibration gas in the range of the expected concentrations. The instrument response was then challenged with other calibration gases of known concentration and accepted as being linear if the response of the other calibration gases agreed within $\pm$ 2 percent of range of the predicted values. The strip chart excerpts that present the results of the initial multi-point linearity test are provided in Appendix D as are Instrumental Quality Assurance Data Sheets and Quality Assurance Worksheets.

In addition to the initial linearity checks, the calibration error checks were repeated as required throughout the tests. Anytime an adjustment was made to an analyzer, the calibration error test was repeated. Adjustment to the analyzer could have occurred for one of three reasons. If the post test run calibration check showed that the analyzer drift was approaching 3% (2% for Method 20), the technician may have chosen to reset the analyzer back to the correct setting before continuing with the next test run. If the drift exceeded 3% (but was less than 5%), the run is considered valid; however, adjustment to the analyzer is made before additional tests are conducted. Additionally, the analyzer span values could be changed. Anytime an adjustment was made to an analyzer for one of these reasons, the calibration error check (and bias check) was repeated before continuing. The Quality Assurance Worksheets of Appendix D summarize these calibration error checks.

Before and after each test run, the analyzers were checked for zero and span drift. This allowed each test run to be bracketed by calibrations and documented the precision of the data just collected. Documentation of drift also allowed for the use of Equation 6c-1 for correction of the observed emission concentrations. Calibrations were made through the entire sample system (via the bias check valve) at the end of every test run. The criterion for acceptable data is that the instrument drift is no more than 3 percent of the full scale response. The quality assurance worksheets in Appendix D summarize all multipoint calibration checks and zero to span checks performed during the tests. These worksheets (as prepared from the strip chart records of Appendix F) show that there were no drifts in excess of 5% and that additional calibration error and bias checks were conducted for any drifts in excess of 3% (2% for Method 20).

Use of Equation 6c-1 requires documentation of both the initial and final zero and calibration responses. When two consecutive test runs were conducted one after the other, the final drift for the previous run was used for the initial calibration response of the subsequent run. In cases where there was a sufficient delay between test runs to deem this strategy invalid, a separate initial calibration was conducted and the response from this calibration was used in Equation 6c-1.

The instrumental sampling system was leak checked by demonstrating that a vacuum greater than 10" Hg could be held for at least 1 minute with a decline of less than 1" Hg. A leak test was conducted after a sample system was set up and before that system was dismantled. These tests were conducted to ensure that ambient air had not diluted the sample. Any leakage detected prior to the tests was repaired and another leak check conducted before testing commenced. No leaks were found during the post test leak checks. Leak check results are summarized on the Instrumental Quality Assurance Worksheets of Appendix D.

The absence of leaks in the sampling system was also verified by system bias checks. The sampling system's integrity was tested by comparing the responses of each of the analyzers used to a calibration gas introduced via two paths. The first path was into the analyzer via the zero/span calibration manifold via the calibration error check. The second path was to introduce a calibration gas into the sample system at the sample probe via the calibration line and switching valve. Any difference in the instrument responses by these two methods was attributed to sampling system bias or leakage. Bias checks were conducted prior to and upon completion of testing for all analyzers. Examination of the strip chart excerpts and Instrumental Analysis Quality Assurance Data worksheets in Appendix D show that the analyzer responses via both sample paths agreed within acceptable limits in all cases.

Bias checks were also conducted at other times throughout the tests as required by the test method. Anytime adjustment to the analyzer or drift in excess of 3% was recorded necessitated a repeat of the calibration error check, the bias check was also repeated. All bias check results are summarized in the Quality Assurance Worksheets of Appendix D.

Prior to testing on each unit, a NO_X converter efficiency check was conducted as required by EPA Methods 7e and 20. To conduct this test, a NO_X calibration gas was blended with air in a Tedlar® bag. Over a 30-minute period, the NO_X concentration was monitored and the NO concentration checked at 5-minute intervals via bypassing of the converter. As shown on the Instrumental Quality Assurance Worksheet of Appendix D, there was no appreciable drop in NO_X concentration (<2%) over the 30-minute period as the NO concentration did drop. Appendix D provides the results of the initial converter efficiency check.

Interference response tests on the instruments were conducted by the instrument vendors and Cubix Corporation on the NO_X, CO, CO_2, and O_2, analyzers. The sum of the interference responses for H_2O, NO_X, CO, SO_2, CO_2 and O_2 (as appropriate for each analyzer) are less than 2 percent of the applicable full scale span value. The instruments used for the tests meet the performance specifications for EPA Methods 3a, 20, 7e, and 10. The results of these direct interference tests are available in Appendix D of this report.

The residence time of the sampling and measurement system was estimated using the pump flow rate and the sampling system volume. The pump's rated flow is 0.8 SCFM at 5 psig. The sampling system volume is 0.13 scf. Therefore, the sample residence time is approximately 10 seconds.

Response time tests were conducted on site on the sample system utilized during the tests. These tests were conducted simultaneously with the initial bias checks and are documented on the Instrumental Quality Assurance Worksheet of Appendix D. Method 20 response time tests were also conducted for the NOx and O_2 sample systems. The response times were found to be ≈1-minute and 2-minutes per point was suitable for the initial O_2 traverses.

The control gases used to calibrate the instruments were analyzed and certified by the compressed gas vendors to ± 1% accuracy or EPA Protocol 1. The gas calibration sheets as prepared by the vendor are contained in Appendix E.

The pitot tubes used during the testing were visually inspected to ensure that they met the criteria of EPA Method 2. The pitot tubes were wind tunnel tested and the results of those tests are contained in Appendix E. The pitot tube lines were leak checked in the field each time connection to the manometer was made in accordance with EPA Method 2 guidelines.

The dry gas meters used for these tests was calibrated prior to testing in accordance with EPA methodology. A post test calibration check was also conducted on the meters. A standard dry gas meter traceable to NIST was used for these calibrations. Calibration certification documentation of the dry gas meters can be found in Appendix E. That documentation shows that the difference between the pre and post test calibrations differed by less than 5% as required by the regulations.

EPA Method 5 quality assurance activities began during preparation for these tests. All glassware was thoroughly washed, rinsed, dried, and stored with protection to prevent contamination. Pre-weighed filters were sealed against contamination and packed safely. Reagent GC grade acetone and deionized water was used for the washing of the sampling train. A blank of the acetone and the water were treated in the same manner as the samples and retained for evaporation and weighing for contaminants. A blank filter was also weighed after treating it in the same manner as the filters used during sampling.

Isokinetic sampling rates were achieved and the isokinetics were checked in the field at each traverse point as well as over the entire test run period. isokinetics between 90% and 110% over the test run are required for Method 5. The PM calculation spreadsheets of Appendix A show that the isokinetics were within acceptable limits in all cases.

Redundant calculation techniques were utilized when possible (i.e. flow rates and moisture via both stoichiometry and manual measurements) for comparative purposes. measurements.

Appendix E contains calibration data on the altimeter, analytical balance, and thermocouples/thermometers used during this testing.

Cubix collected and reported the enclosed test data in accordance with the procedures and quality assurance activities described in this test report. Cubix makes no warranty as to the suitability of the test methods. Cubix assumes no liability relating to the interpretation and use of the test data.

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METCO ENVIRONMENTAL

SOURCE EMISSIONS SURVEY
OF
CALPINE CORPORATION
PASADENA II POWER FACILITY
COMBINED CYCLE GAS FIRED
UNIT STACK
PASADENA, TEXAS

HOUSTON, TEXAS DALLAS, TEXAS BATON ROUGE, LOUISIANA

METCO ENVIRONMENTAL

RECEIVED NOV 2 3 1999

SOURCE EMISSIONS SURVEY
OF
CALPINE CORPORATION
PASADENA II POWER FACILITY
COMBINED CYCLE GAS FIRED
UNIT STACK
PASADENA, TEXAS

SEPTEMBER AND OCTOBER 1999

FILE NUMBER 99-281

METCO ENVIRONMENTAL

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SOURCE EMISSIONS SURVEY
CALPINE CORPORATION
PASADENA II POWER FACILITY
COMBINED CYCLE GAS FIRED UNIT STACK
PASADENA, TEXAS
FILE NUMBER 99-281

INTRODUCTION

METCO Environmental, Dallas, Texas, conducted a source emissions survey of Calpine Corporation, Pasadena II Power Facility, located in Pasadena, Texas on September 20, 21, 22, and October 18 and 19, 1999. The purposes of these tests was to determine the concentrations of particulate matter, sulfur dioxide, sulfur trioxide, oxides of nitrogen, carbon monoxide, and total hydrocarbons being emitted to the atmosphere via the Combined Cycle Gas Fired Unit Stack. The carbon monoxide and the total hydrocarbons testing was performed at four different operating conditions.

The sampling followed the procedures set forth in the Code of Federal Regulations, Title 40, Chapter I, Part 60, Appendix A, Methods 1, 2, 3A, 3B, 4, 5, 6, 7E, 8, 10, and 25A; and in the "Sampling Procedure Manual, Texas Air Control Board, Revised July 1985."

METCO ENVIRONMENTAL

SUMMARY OF RESULTS

Combined Cycle Gas Fired Unit Stack

Date	Time	Oxides of Nitrogen Emissions (dry ppm*)	Carbon Monoxide Emissions (dry ppm)	Total Hydrocarbons as Propane (dry ppm)	(Comments-Load)
09/20/99, 09/21/99	2315-0015	3.1	7.0	0.1	Power Augmentation Off
09/21/99	0115-0215	3.0	19.9	0.1	60% Load
09/21/99	0230-0330	3.0	8.1	<0.1	70% Load

* Monitor was not calibrated.

SUMMARY OF RESULTS

Combined Cycle Gas Fired Unit Stack

Run Number	Oxides of Nitrogen Emissions (dry ppm)	(dry ppm**)	(lbs/hr)	Carbon Monoxide Emissions (dry ppm)	(dry ppm**)	(lbs/hr)	Total Hydrocarbons Emissions as Propane (dry ppm)	(lbs/hr)	Comments
1	4.3	3.3	25.41	2.6	2.0	9.36	<0.1	<0.57	Base Load-Power Augmentation On
2	5.2	4.1	30.77	1.9	1.5	6.85	<0.1	<0.57	Base Load-Power Augmentation On
3	4.5	3.5	26.56	1.7	1.3	6.11	≤0.1	≤0.57	Base Load-Power Augmentation On
Average	4.7	3.6	27.58	2.1	1.6	7.44	<0.1	<0.57	

Run Number	Particulate Matter Emissions (gr/dscf*)	(lbs/hr)	Sulfur Dioxide Emissions (dry ppm)	(lbs/hr)	Sulfuric Acid Emissions (dry ppm)	(lbs/hr)	Comments
1	0.0007	4.47	N.D.	N.D.	0.02	0.18	Power Augmentation Off
2	0.0007	5.02	0.2	1.8	0.09	1.08	Power Augmentation Off
3	0.0011	6.75	0.2	1.6	≤0.01	≤0.06	Power Augmentation Off
Average	0.0008	5.41	0.1	1.1	0.04	<0.44	

* 29.92 "Hg, 68°F (760 mm Hg, 20°C)

** Corrected to 15 percent oxygen.

N.D. - None detected.

METCO ENVIRONMENTAL

SUMMARY OF RESULTS

Combined Cycle Gas Fired Unit Stack

Run Number	1	2
Date	09/22/99	09/22/99
Time	0845-1509	1654-2112
Stack Flow Rate - ACFM	1,237,553	1,210,008
Stack Flow Rate - DSCFM*	826,037	823,998
% Water Vapor - % Vol.	11.41	9.42
% CO_2 - % Vol.	4.3	4.4
% O_2 - % Vol. (orsat)	13.2	13.2
% O_2 - % Vol. (monitor)	13.4	13.3
% Excess Air @ Sampling Point	152	153
Stack Temperature -°F	242	243
Stack Pressure - "Hg	29.86	29.84

* 29.92 "Hg, 68°F (760 mm Hg, 20°C)

N.D. - None detected.

SUMMARY OF RESULTS

Combined Cycle Gas Fired Unit Stack

Run Number	1	2	3
Date	09/21/99	09/22/99	09/22/99
Time	1221-1621	0845-1251	1654-2100
Stack Flow Rate - DSCFM*	825,018***	826,037	823,998
Oxides of Nitrogen Emissions - dry ppm	4.3	5.2	4.5
Oxides of Nitrogen Emissions - dry ppm**	3.3	4.1	3.5
Oxides of Nitrogen Emissions - lbs/hr	25.41	30.77	26.56
Carbon Monoxide Emissions - dry ppm	2.6	1.9	1.7
Carbon Monoxide Emissions - dry ppm**	2.0	1.5	1.3
Carbon Monoxide Emissions - lbs/hr	9.36	6.85	6.11
Total Hydrocarbons Emissions as Propane - wet ppm	<0.1	<0.1	<0.1
Total Hydrocarbon Emissions as Propane - dry ppm	<0.1	<0.1	<0.1
Total Hydrocarbon Emissions as Propane - lbs/hr	<0.57	<0.57	<0.57
Oxygen Concentrations - % Vol.	13.2	13.4	13.3

* 29.92 "Hg, 68°F (760 mm Hg, 20°C)

** Corrected to 15 percent oxygen.

*** Average flowrate from Run Numbers 2 and 3.

METCO ENVIRONMENTAL

SUMMARY OF RESULTS

Combined Cycle Gas Fired Unit Stack

Run Number	1	2	3
Date	10/18/99	10/19/99	10/19/99
Time	1300-1727	0814-1233	1339-1812
Stack Flow Rate - ACFM	1,115,429	1,134,805	1,048,242
Stack Flow Rate - DSCFM*	769,315	785,604	730,562
% Water Vapor - % Vol.	8.22	8.32	7.83
% CO_2 - % Vol.	4.1	3.8	4.0
% O_2 - % Vol.	13.7	14.1	14.0
% Excess Air @ Sampling Point	170	184	181
Stack Temperature -°F	244	243	242
Stack Pressure - "Hg	29.87	29.97	29.97
Percent Isokinetic	101.6	101.2	106.0
Volume Dry Gas Sampled - DSCF*	170.417	173.380	160.086
Particulate Matter Emissions Probe & Filter Catch grains/dscf*	0.0004	0.0004	0.0006
grains/cf @ Stack Conditions	0.0002	0.0003	0.0004
lbs/hr	2.38	2.75	3.85
Total Catch grains/dscf*	0.0007	0.0007	0.0011
grains/cf @ Stack Conditions	0.0005	0.0005	0.0007
lbs/hr	4.47	5.02	6.75
Sulfur Dioxide Emissions - dry ppm	0.0	0.2	0.2
Sulfur Dioxide Emissions - lbs/hr	0.0	1.8	1.6
Sulfuric Acid - mg	0.3	1.8	<0.1
Sulfuric Acid Emissions - dry ppm	0.02	0.09	<0.01
Sulfuric Acid Emissions - lbs/hr	0.18	1.08	<0.06

* 29.92 "Hg, 68°F (760 mm Hg, 20°C)

DISCUSSION OF RESULTS

The three tests for oxides of nitrogen, carbon monoxide, and total hydrocarbons and the two tests for flow rate appeared to be valid representations of the actual emissions during the tests. All leak checks performed on the sampling train, the pitot tubes, and the reference method monitors sampling systems showed no leaks before or after each test. The zero and calibration drift tests of the reference method monitors were stable with no variations greater than 3.0 percent. The calibration error check, sampling system bias check, and NO_2 to NO conversion efficiency check performed on the reference method monitor prior to testing were valid. The indicative parameters calculated from the field data were in close agreement. The moisture percentages for the two tests were within 9.6 percent of the mean value. The measured flow rates (Q_s) for the tests were within 0.1 percent of the mean value.

The calculated emissions (pounds per hour) of oxides of nitrogen for the three tests showed a range of -7.9 percent to +11.6 percent variation from the mean value.

The calculated emissions (pounds per hour) of carbon monoxide for the three tests showed a range of -17.9 percent to +25.8 percent variation from the mean value.

The concentrations of total hydrocarbons for the three tests were below the minimum detectable limit of the method.

The first set of tests for PM 10 particulate matter, sulfuric acid, and sulfur dioxide were invalid due to sample contamination.

The three tests for particulate matter, sulfuric acid and sulfur dioxide appeared to be valid representations of the actual emissions during the tests. All leak checks performed on the sampling train and the pitot tubes showed no leaks before or after each test. The indicative parameters calculated from the field data were in close agreement. The moisture percentages for the three tests were within 3.6 percent of the mean value. The measured flow rates (Q_s) for the tests were within 4.1 percent of the mean value. The rates of sampling for the three tests were within the specified limits (90 to 110 percent isokinetic). The greatest deviation from 100 percent isokinetic was 6.0 percent.

The calculated emissions (pounds per hour) of particulate matter for the three tests showed a range of -17.4 percent to +24.7 percent variation from the mean value.

The concentrations of sulfur dioxide for one of the three tests were below the minimum detectable limit of the method.

The concentrations of sulfuric acid for one of the three tests were below the minimum detectable limit of the method.

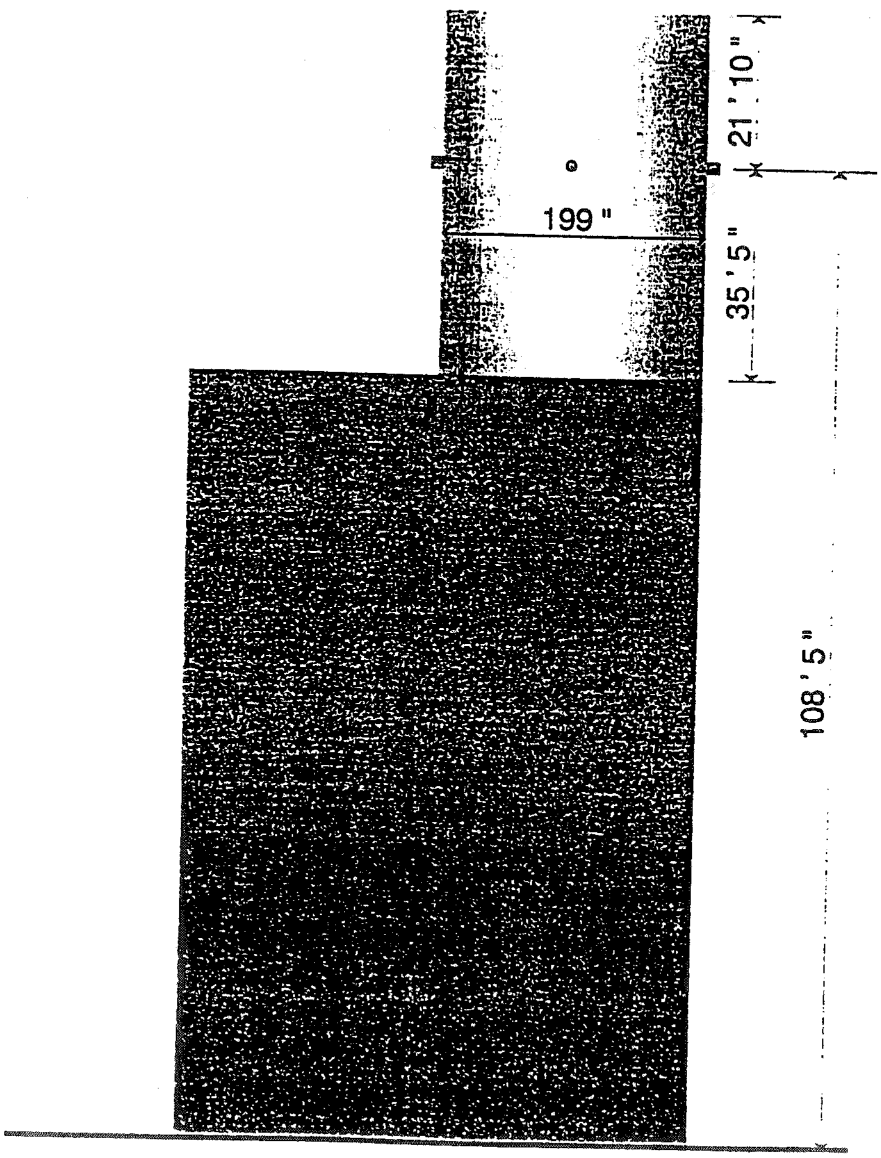
METCO Environmental

DESCRIPTION OF SAMPLING LOCATION

The sampling location on the Combined Cycle Gas Fired Unit Stack is 108 feet 5 inches above the ground. The sampling ports are located 35 feet 5 inches (2.14 stack diameters) downstream from a constriction in the stack and 21 feet 10 inches (1.32 stack diameters) upstream from the outlet of the stack.

SAMPLING LOCATION

Combined Cycle Gas Fired Unit Stack



Not to Scale

SAMPLING AND ANALYTICAL PROCEDURES

The sampling followed the procedures set forth in the Code of Federal Regulations, Title 40, Chapter I, Part 60, Appendix A, Methods 1, 2, 3A, 3B, 4, 5, 6, 7E, 8, 10, and 25A; and in the "Sampling Procedures Manual, Texas Air Control Board, Revised July 1985."

A preliminary velocity traverse was made at each of the four ports on the stack, in order to determine the uniformity and magnitude of the flow prior to testing. All traverse points were checked for cyclonic flow and the average angle of flow was equal to 9.5 degrees. Alternate procedures would be required if the angle of cyclonic flow was greater than 20 degrees. Six traverse points were sampled from each of the four ports for a total of twenty-four traverse points.

The sampling train was leak-checked at the nozzle at 15 inches of mercury vacuum before each test, and again after each test at the highest vacuum reading recorded during the test. This was done to predetermine the possibility of a diluted sample.

The pitot tube lines were checked for leaks before and after each test under both a vacuum and a pressure. The lines were also checked for clearance and the manometer was zeroed before each test.

An integrated orsat sample was collected and analyzed according to EPA Method 3B during each test.

Particulate Matter/Sulfur Dioxide/Sulfuric Acid

Triplicate samples for particulate matter, sulfur dioxide and sulfuric acid were collected. The samples were taken according to EPA Methods 1, 2, 3B, 4, 5, 6, and 8; and the "Sampling Procedures Manual, Texas Air Control Board, Revised July 1985." Large impingers (500 ml) as specified in EPA Method 8, were used. For each run, samples of twenty-minute duration were taken isokinetically at each of the twelve traverse points for a total sampling time of 240 minutes. Data was recorded at five-minute intervals. Reagent blanks were submitted. At the conclusion of each run, the sampling train was purged for fifteen minutes with ambient air at the same rate at which the sample was taken.

The " front-half " of the sampling train contained the following components:

Stainless Steel Nozzle
Heated Glass Probe @ 248°F ± 25°F
Heated Glass Fiber Filter and Glass Support @ 248°F ± 25°F

The " back-half " of the sampling train contained the following components:

Impinger Number	Contents	Amount	Parameter Collected
1	80% Isopropyl Alcohol	200 ml	Particulate Matter and Sulfuric Acid
	Method 8 filter	----	Sulfuric Acid
2	6% Hydrogen Peroxide	200 ml	Sulfur Dioxide
3	6% Hydrogen Peroxide	200 ml	Sulfur Dioxide
4	Empty	--------	Moisture
5	Silica Gel	200 g	Moisture

The isopropyl alcohol solution in the first impinger was checked for hydrogen peroxide contamination and none was found.

Particulate matter emissions were calculated from gravimetric analysis using both the "front-half" and "back-half" collections of the sampling train.

The sulfur dioxide and sulfuric acid samples were analyzed by barium perchlorate titration using thorin indicator. The Method 8 filters were analyzed for sulfuric acid by ion chromatography.

Oxides of Nitrogen

The oxides of nitrogen sampling was performed according to EPA Method 7E. A Thermo Environmental Model 10S Oxides of Nitrogen Analyzer (Serial Number 10S-49429-282) was used to monitor the concentrations of oxides of nitrogen during each run. The reference method analyzer was operated at a range of 0 to 100 parts per million. A multi-point calibration was performed on the reference method analyzer prior to testing. An analyzer calibration error check, a sampling system bias check, and a NO_2 to NO conversion efficiency check were also conducted prior to testing. After each run, the zero and calibration drift of the reference method monitor was checked. The calibration gases were as follows:

Zero Nitrogen
27.3 ppm NO in N_2 (ALM 2469)
50.2 ppm NO in N_2 (BAL 1605)
83.7 ppm NO in N_2 (BLM 1098)

The reference method sampling systems consisted of a heated probe, a heated glass fiber filter, a chilled condenser, and a teflon sample line. The calibration gases for the bias and drift checks were introduced upstream of the chilled condenser.

Calibration gas certifications are included in Appendix C.

Carbon Monoxide

The carbon monoxide sampling was performed according to EPA Method 10 using the continuous sampling procedure. Thermo Environmental Model 48 Carbon Monoxide Analyzer (Serial Number 48-39616-261) was used to monitor the concentrations of carbon monoxide during each run. The reference method analyzer was operated at a range of 0 to 100 parts per million. A multi-point calibration was performed on the reference method analyzer prior to testing. An analyzer calibration error check and a sampling system bias check were also conducted prior to testing. After each run, the zero and calibration drift of the reference method monitor was checked. The calibration gases were as follows:

Zero Nitrogen
17.2 ppm CO in N_2 (BAL 3795)
43.9 ppm CO in N_2 (BLM 3379)
88.5 ppm CO in N_2 (BAL 3672)

The reference method sampling systems consisted of a heated probe, a heated glass fiber filter, a chilled condenser, and a teflon sample line. The calibration gases for the bias and drift checks were introduced upstream of the chilled condenser.

Calibration gas certifications are included in Appendix C.

Total Hydrocarbons

The total hydrocarbons sampling was performed according to EPA Methods 25A. J.U.M. Model VE-7 Total Hydrocarbon Analyzer (Serial Number 101941092T) was used to monitor the concentrations of total hydrocarbons during each run. The reference method analyzers were operated at ranges of 0 to 100 parts per million. A multi-point calibration was performed on the reference method analyzers prior to testing. An analyzer calibration error check and a sampling system bias check were also conducted prior to testing. After each run, the zero and calibration drift of the reference method monitors was checked. The calibration gases were as follows:

Zero Nitrogen

22.5 ppm C_3H_8 in N_2 (BAL 1786)

48.1 ppm C_3H_8 in N_2 (BLM 3022)

85.2 ppm C_3H_8 in N_2 (BLM 3837)

The reference method sampling systems consisted of heated probe and a heated teflon sample line. The calibration gases for the bias and drift checks were introduced upstream of the heated teflon sample line.

Calibration gas certifications are included in Appendix C.

Oxygen

The oxygen sampling was performed according to EPA Method 3A. A Teledyne Model 326 Oxygen Analyzer (Serial Number 132689) was used to monitor the concentrations of oxygen during each run. The reference method analyzer was operated at a range of 0 to 25 percent. A multi-point calibration was performed on the reference method analyzer prior to testing. An analyzer calibration error check and a sampling system bias check were also conducted prior to testing. After each run, the zero and calibration drift of the reference method monitor was checked. The calibration gases were as follows:

Zero Nitrogen
11.9 percent O_2 in N_2 (ALM 5329)
20.9 percent O_2 in ambient air

The reference method sampling system consisted of a heated probe, a heated glass fiber filter, a chilled condenser, and a teflon sample line. The calibration gases for the bias and drift checks were introduced upstream of the chilled condenser.

Calibration gas certifications are included in Appendix C.

METCO ENVIRONMENTAL

DESCRIPTION OF TESTS

Personnel from METCO Environmental arrived at the plant at 9:45 a.m. on Monday, September 20, 1999. After meeting with plant personnel and attending a brief safety orientation, the equipment was moved onto the Combined Cycle Gas Fired Unit Stack. The monitors were calibrated and the equipment was prepared for testing. The preliminary data was collected. The preliminary oxygen traverse began at 3:55 p.m. and was completed at 5:20 p.m. Continuous monitoring for carbon monoxide and total hydrocarbons began at 7:22 p.m. and was completed at 3:30 a.m. on Tuesday, September 21, 1999. The equipment was secured for the night and all work was completed at 8:00 p.m.

On Tuesday, September 21, work began at 6:45 a.m. The monitors were calibrated and the equipment was prepared for testing. The first test for PM 10 particulate matter, sulfuric acid, sulfuric dioxide, oxides of nitrogen, carbon monoxide and total hydrocarbons began at 12:21 p.m. and was completed at 4:21 p.m. The first test for PM 10 particulate matter, sulfuric acid, and sulfur dioxide was aborted due to monorail bracket problems. The monitors were calibrated. The equipment was secured for the night and all work was completed at 5:30 p.m.

On Wednesday, September 22, work began at 6:45 a.m. The monitors were calibrated and the equipment was prepared for testing. The first test for PM 10 particulate matter, sulfuric acid, and sulfur dioxide and the second test for oxides of nitrogen, carbon monoxide, and total hydrocarbons began at 8:45 a.m. Testing continued until the completion of the second test at PM 10 particulate matter, sulfuric acid, and sulfur dioxide and the third test for oxides of nitrogen, carbon monoxide, and total hydrocarbons at 9:13 p.m.

The monitors were calibrated and secured for transport. The equipment was moved off of the stack and loaded into the sampling van. The samples were recovered and transported to METCO Environmental's laboratory in Dallas, Texas, for analysis and evaluation.

Personnel from METCO Environmental returned to the plant at 9:30 a.m. on Monday, October 18, 1999. After meeting with plant personnel the equipment was moved onto the Combined Cycle Gas Fired Unit Stack and prepared for testing. The preliminary data was collected. The first test for particulate matter, sulfuric acid, and sulfur dioxide began at 1:00 p.m. and was completed at 5:27 p.m. The samples were recovered. The equipment was secured for the night and all work was completed at 6:30 p.m.

On Tuesday, October 19, work began at 6:45 a.m. The equipment was prepared for testing. The second test for particulate mater, sulfuric acid, and sulfur dioxide began at 8:14 a.m. Testing continued until the completion of the third test at 6:12 p.m.

The equipment was moved off of the stack and loaded into the sampling van. The samples were recovered and transported to METCO Environmental's laboratory in Dallas, Texas, for analysis and evaluation.

Operations at Calpine Corporation, Pasadena II Power Facility, Combined Cycle Gas Fired Unit Stack, located in Pasadena, Texas, were completed at 7:45 p.m. on Tuesday, October 19, 1999.

Billy J. Mullins, Jr. P.E.
President

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2.0 SUMMARY OF RESULTS

The following table summarizes each parameter that was tested and the emission limit for each.

Unit 2		Natural Gas		Fuel Oil	
Parameter	Load	Measured Emission	Emission Limit	Measured Emission	Emission Limit
PM/PM10 including back-half, lb/hr	70%	10.0	18.0	22.7	44.0
	85%	10.7	18.0	30.1	44.0
	100%	16.8	18.0	43.6	44.0
Visible Emissions, % Opacity	70%	0	20	0	20
	85%	0	20	0	20
	100%	0	20	0	20
Lead, lb/hr	100%	<0.017	0.025	<0.017	0.025
H_2SO_4 mist (as SO_3), lb/hr	100%	10.84	0.36	11.34	12.50
CO, ppmvd @ 15% O_2	55%	0.4	12	0.2	24
	70%	0.3	12	0.1	24
	85%	0.7	12	0.2	15
	100%	0.4	12	0.5	15
NO_X, ppmvd @ 15% O_2	55%	9.6	15	36.8	42
	70%	8.0	15	36.1	42
	85%	6.6	15	35.0	42
	100%	8.7	15	36.1	42
VOC, ppmvd @ 15% O_2	55%	0.0	2.0	0.0	5.0
	70%	0.9	2.0	0.2	5.0
	85%	0.3	2.0	0.0	5.0
	100%	0.5	2.0	0.3	5.0
SO_2, lb/hr	100%	0.22	4.38	44.0	98.0
Sulfur content in fuel oil, % by weight	N/A			0.048	0.05

Complete test results summaries are tabulated and can be found on pages 11 through 28.

Unit operating data was recorded and retained by [redacted] plant personnel. Fuel samples were obtained during the testing for analysis. Results of these analyses are appended.

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TOTAL PARTICULATE TEST RESULTS SUMMARY				
Plant [redacted]	Source: Unit 2			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	100% Load Fuel Oil			
Fuel Factor (dscf/10^6Btu)	9222	9222	9222	
Date	05/02/2000	05/02/2000	05/02/2000	
Time	0340-0655	0745-1107	2040-0002	
Total Particulate Concentration:				
@ Flue Conditions, grains/acf	0.0010	0.0019	0.0029	0.0019
@ Standard Conditions, grains/dscf	0.0032	0.0063	0.0096	0.0064
Total Emission Rate:				
pounds/hour	21.713	44.510	64.683	43.635
pounds/10^6 Btu	0.0105	0.0207	0.0314	0.0209
Visible Emission, % Opacity	0.0	0.0	0.0	0.0
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	2,591,215	2,732,239	2,588,660	2,637,371
@ Standard Conditions, dscfm	787,249	823,641	786,815	799,235
Average Gas Temperature, °F	1,072	1,075	1,071	1.073
Average Gas Velocity, ft/sec	169.714	178.951	169.547	172.737
Flue Gas Moisture, percent by volume	10.5	10.6	10.4	10.5
Average Flue Pressure, in. Hg	29.48	29.33	29.44	
Barometric Pressure, in. Hg	29.58	29.43	29.54	
Average %CO_2 by volume, dry basis	6.4	6.4	6.2	6.3
Average %O_2 by volume, dry basis	12.5	12.5	12.5	12.5
Dry Molecular Wt. of Gas, lb/lb-mole	29.524	29.524	29.492	
Gas Sample Volume, dscf	122.756	127.997	122.913	
Isokinetic Variance	101.1	100.8	101.3	

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FILTERABLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted] Source: Unit 2				
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	100% Load Fuel Oil			
Date	05/02/2000	05/02/2000	05/02/2000	
Time	0340-0655	0745-1107	2040-0002	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0004	0.0004	0.0004	0.0004
@ Standard Conditions, grains/dscf	0.0014	0.0014	0.0012	0.0013
Emission Rate:				
pounds/hour	9.500	9.957	8.043	9.167
pounds/10^6 Btu	0.0046	0.0046	0.0039	0.0044

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted] Source: Unit 2				
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	100% Load Fuel Oil			
Date	05/02/2000	05/02/2000	05/02/2000	
Time	0340-0655	0745-1107	2040-0002	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0005	0.0015	0.0026	0.0015
@ Standard Conditions, grains/dscf	0.0018	0.0049	0.0084	0.0050
Emission Rate:				
pounds/hour	12.214	34.553	56.640	34.469
pounds/10^6 Btu	0.0059	0.0160	0.0275	0.0165

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TOTAL PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]. Source: Unit 2				
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Fuel Factor (dscf/10^6Btu)	9214	9214	9214	
Date	05/01/2000	05/01/2000	05/01/2000	
Time	0100-0445	0800-1115	1544-1900	
Total Particulate Concentration:				
@ Flue Conditions, grains/acf	0.0016	0.0010	0.0018	0.0015
@ Standard Conditions, grains/dscf	0.0052	0.0035	0.0061	0.0049
Total Emission Rate:				
pounds/hour	32.597	19.995	37.798	30.130
pounds/10^6 Btu	0.0168	0.0111	0.0195	0.0158
Visible Emissions, % Opacity	0.0	0.0	0.0	0.0
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	2,450,580	2,315,750	2,468,671	2,411,667
@ Standard Conditions, dscfm	730,883	673,208	721,728	708,606
Average Gas Temperature, °F	1,081	1,098	1,096	1,092
Average Gas Velocity, ft/sec	160.503	151.672	161.688	157.954
Flue Gas Moisture, percent by volume	11.4	11.5	11.1	11.3
Average Flue Pressure, in. Hg	29.41	29.00	29.00	
Barometric Pressure, in. Hg	29.51	29.10	29.10	
Average %CO_2 by volume, dry basis	6.4	6.5	6.5	6.5
Average %O_2 by volume, dry basis	12.4	12.3	12.3	12.3
Dry Molecular Wt. of Gas, lb/lb-mole	29.520	29.532	29.532	
Gas Sample Volume, dscf	108.239	103.311	115.157	
Isokinetic Variance	101.0	99.5	103.5	

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FILTERABLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 2			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Date	05/01/2000	05/01/2000	05/01/2000	
Time	0100-0445	0800-1115	1544-1900	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0005	0.0002	0.0005	0.0004
@ Standard Conditions, grains/dscf	0.0018	0.0006	0.0017	0.0014
Emission Rate:				
pounds/hour	11.163	3.275	10.693	8.377
pounds/10^6 Btu	0.0058	0.0018	0.0055	0.0044

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 2			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Date	05/01/2000	05/01/2000	05/01/2000	
Time	0100-0445	0800-1115	1544-1900	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0010	0.0008	0.0013	0.0010
@ Standard Conditions, grains/dscf	0.0034	0.0029	0.0044	0.0036
Emission Rate:				
pounds/hour	21.434	16.720	27.105	21.753
pounds/10^6 Btu	0.0111	0.0093	0.0140	0.0115

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TOTAL PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted] Source: Unit 2				
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Fuel Factor (dscf/10^6Btu)	9214	9214	9214	
Date	05/01/2000	05/01/2000	05/01/2000	
Time	1144-1511	1930-2258	2325-0258	
Total Particulate Concentration:				
@ Flue Conditions, grains/acf	0.0011	0.0012	0.0014	0.0012
@ Standard Conditions, grains/dscf	0.0038	0.0039	0.0047	0.0041
Total Emission Rate:				
pounds/hour	20.592	21.623	25.903	22.706
pounds/10^6 Btu	0.0122	0.0128	0.0153	0.0134
Visible Emissions, % Opacity	0.0	0.0	0.0	0.0
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	2,212,459	2,180,776	2,175,032	2,189,422
@ Standard Conditions, dscfm	629,602	639,734	640,011	636,449
Average Gas Temperature, °F	1,138	1,117	1,117	1,124
Average Gas Velocity, ft/sec	144.907	142.832	142.456	143.398
Flue Gas Moisture, percent by volume	11.2	11.1	10.9	11.1
Average Flue Pressure, in. Hg	29.02	29.50	29.50	
Barometric Pressure, in. Hg	29.10	29.58	29.58	
Average %CO_2 by volume, dry basis	6.5	6.4	6.4	6.4
Average %O_2 by volume, dry basis	12.3	12.4	12.4	12.4
Dry Molecular Wt. of Gas, lb/lb-mole	29.532	29.520	29.520	
Gas Sample Volume, dscf	106.353	108.388	107.836	
Isokinetic Variance	102.7	103.0	102.4	

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FILTERABLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 2			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Date	05/01/2000	05/01/2000	05/01/2000	
Time	1144-1511	1930-2258	2325-0258	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0003	0.0003	0.0003	0.0003
@ Standard Conditions, grains/dscf	0.0012	0.0012	0.0011	0.0012
Emission Rate:				
pounds/hour	6.342	6.401	5.966	6.236
pounds/10^6 Btu	0.0038	0.0038	0.0035	0.0037

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Date	05/01/2000	05/01/2000	05/01/2000	
Time	1144-1511	1930-2258	2325-0258	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0008	0.0008	0.0011	0.0009
@ Standard Conditions, grains/dscf	0.0026	0.0028	0.0036	0.0030
Emission Rate:				
pounds/hour	14.250	15.222	19.938	16.470
pounds/10^6 Btu	0.0084	0.0090	0.0118	0.0097

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2.0 SUMMARY OF RESULTS

The following table summarizes each parameter that was tested and the emission limit for each.

Unit 1		Natural Gas		Fuel Oil	
Parameter	Load	Measured Emission	Emission Limit	Measured Emission	Emission Limit
PM/PM10 including back-half, lb/hr	70%	2.7	18.0	26.4	44.0
	85%	7.1	18.0	27.8	44.0
	100%	10.4	18.0	31.4	44.0
Visible Emissions, % Opacity	70%	0	20	0	20
	85%	0	20	0	20
	100%	0	20	0	20
Lead, lb/hr	100%	<0.013	0.025	<0.018	0.025
H_2SO_4 mist (as SO_3), lb/hr	100%	4.12	0.36	19.11	12.50
CO, ppmvd @ 15% O_2	55%	0.4	12	0.0	24
	70%	0.4	12	0.0	24
	85%	0.5	12	0.1	15
	100%	0.5	12	0.0	15
NO_X, ppmvd @ 15% O_2	55%	8.6	15	35.9	42
	70%	7.9	15	34.4	42
	85%	6.6	15	35.2	42
	100%	9.2	15	36.9	42
VOC, ppmvd @ 15% O_2	55%	0.7	2.0	0.8	5.0
	70%	0.6	2.0	1.4	5.0
	85%	0.4	2.0	0.7	5.0
	100%	0.3	2.0	0.3	5.0
SO_2, lb/hr	100%	1.04	4.38	31.7	98.0
Sulfur content in fuel oil, % by weight	N/A			0.049	0.05

39%

Complete test results summaries are tabulated and can be found on pages 11 through 28.

Unit operating data was recorded and retained by [redacted]plant personnel. Fuel samples were obtained during the testing for analysis. Results of these analyses are appended.

balance nitrogen calibration gases) was introduced during other instrument calibrations to check instrument zero. High- and a mid-range % O_2 levels in balance nitrogen were also introduced. Mid-range calibrations were performed using Protocol One gas prior to and between each test run.

4.4 Carbon Dioxide (CO_2) Determination

A carbon dioxide (CO_2) analyzer was used to determine CO_2 concentrations in the stack gas in accordance with Method 3A, 40CFR60. This instrument has a nondispersive infrared-based detector and operates in a range of 0-20% CO_2. A high- and mid-range calibration was performed using Protocol One gases, and non-CO_2-containing gas mixtures were used for the CO_2 zero. Mid-range and zero calibrations were performed prior to and between each test run.

4.5 Particulate Determination

A total of 24 test points were sampled using 4 ports at the Unit 1 stack test location.

The particulate sample train was manufactured by Nutech Corporation of Durham, North Carolina and meets all specifications required by Method 5, 40CFR60. A quartz -lined probe was used. Drawings depicting the sampling ports, test point locations, and sample trains are appended to this report. Velocity pressures were determined simultaneously during sampling with a calibrated S-type pitot tube and inclined manometer. All temperatures were measured using K-type thermocouples with calibrated digital temperature indicators.

The filter media were Whatman 934-AH glass microfibre filters exhibiting a ≥ 99.97 % efficiency on 0.3 micron DOP smoke particles in accordance with ASTM Standard Method D-2986-71. All front half sample contact surfaces of the train were washed with HPLC reagent-grade acetone. Deionized water and methylene chloride were used to rinse the back half. These washes were placed in sealed and marked containers for analysis.

All sample recovery was performed at the test site by the test crew. All final particulate sample analyses were performed by [redacted]ersonnel at the [redacted] laboratory in [redacted] including Method 202 back half requirements. Copies of all sample analysis sheets, explanations of nomenclature and calculations, and raw field data sheets are appended to this report.

4.6 Condensible Particulate Matter Determination

This method applies to the determination of condensible particulate matter (CPM) emissions from stationary sources. It is intended to represent condensible matter as material that condenses after passing through a filter and as measured by this method.

The CPM is collected in the impinger portion of Method 5 type sampling train. The impinger contents are immediately purged after the run with nitrogen (N_2) to remove dissolved sulfur dioxide (SO_2) gases from the impinger contents. The impinger solution is then extracted with methylene chloride ($MeCl_2$). The organic and aqueous fractions are then taken to dryness and the residues weighed. A correction is made for any ammonia present due to laboratory analysis procedures. The total of both fractions represents the CPM.

4.7 Sulfur Dioxide (SO_2) Determination

Method 6C, 40CFR60, test procedure was used to determine sulfur dioxide (SO_2) emissions from the source. A gas sample was continuously extracted from the stream through a heated sampling probe and gas conditioning system to remove the moisture. A portion of the gas stream was conveyed to the gas analyzer for determination of SO_2 content.

Prior to sampling, the SO_2 analyzer was zeroed and calibrated with high-range, mid-range, and zero gases. Between each test run, zero and mid-range calibration gases were introduced to check calibration.

The design of the Western Research 721T analyzer is based on a single source emitting the appropriate wavelengths. The radiation from the source was segmented by a single pair of narrow band pass radiation rejection filters continuously rotated through the radiation path and then split into two paths; measuring and reference. The measuring path contained the cell through which the sample was passed; the reference path contained the "sealed" sample cell, which was filled with instrument-quality air. The radiation passed by the cells was then detected by a pair of photomultiplier tubes (PMT); one for each radiation path. These signals were used in the calculations of the final output.

4.8 Nitrogen Oxides (NO_x) Determination

Method 20, 40CFR60, was used for determining nitrogen oxides (NO_x), sulfur dioxide (SO_2) (at 100 % load only), and oxygen (O_2) emissions from the gas turbines. A gas sample was continuously extracted from the gas exhaust stream of the gas turbine through a heated sampling probe. A portion of the sample stream was conveyed via a heated sampling line to gas analyzers for determination of NO_x and O_2 content. The O_2 determination was used to adjust the NO_x concentrations to a reference condition.

FILTERABLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	100% Load Fuel Oil			
Date	04/27/00	04/28/00	04/29/00	
Time	2007-2353	1140-1543	2110-0035	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0004	0.0004	0.0006	0.0005
@ Standard Conditions, grains/dscf	0.0012	0.0014	0.0019	0.0015
Emission Rate:				
pounds/hour	8.538	10.182	13.516	10.745
pounds/10^6 Btu	0.0039	0.0047	0.0062	0.0049

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	100% Load Fuel Oil			
Date	04/27/00	04/28/00	04/29/00	
Time	2007-2353	1140-1543	2110-0035	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0009	0.0009	0.0008	0.0009
@ Standard Conditions, grains/dscf	0.0030	0.0030	0.0027	0.0029
Emission Rate:				
pounds/hour	21.458	21.355	19.207	20.673
pounds/10^6 Btu	0.0098	0.0098	0.0088	0.0095

TOTAL PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted] **Source: Unit 1**

Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Fuel Factor (dscf/10^6 Btu)	9217	9217	9217	
Date	04/30/00	04/30/00	04/30/00	
Time	0045-0414	0730-1050	1127-1447	
Total Particulate Concentration:				
@ Flue Conditions, grains/acf	0.0011	0.0014	0.0014	0.0013
@ Standard Conditions, grains/dscf	0.0037	0.0050	0.0049	0.0045
Total Emission Rate:				
pounds/hour	23.222	30.451	29.812	27.828
pounds/10^6 Btu	0.0119	0.0160	0.0158	0.0146
Visible Emissions. % Opacity	0.0	0.0	0.0	0.0
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	2,445,937	2,460,260	2,487,213	2,464,470
@ Standard Conditions, dscfm	722,983	704,263	711,904	713,050
Average Gas Temperature, °F	1,105	1,141	1,141	1,129
Average Gas Velocity, ft/sec	160.199	161.137	162.902	161.413
Flue Gas Moisture, percent by volume	10.9	11.4	11.4	11.2
Average Flue Pressure, in. Hg	29.41	29.31	29.31	
Barometric Pressure. in. Hg	29.51	29.41	29.41	
Average %CO_2 by volume, dry basis	6.50	6.50	6.50	6.50
Average %O_2 by volume, dry basis	12.20	12.20	12.40	12.30
Dry Molecular Wt. Of Gas, lb/lb-mole	29.528	29.528	29.536	
Gas Sample Volume, dscf	113.645	102.775	103.591	
Isokinetic Variance	100.5	99.5	99.3	

FILTERABLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Date	04/30/00	04/30/00	04/30/00	
Time	0045-0414	0730-1050	1127-1447	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0004	0.0005	0.0006	0.0005
@ Standard Conditions, grains/dscf	0.0015	0.0018	0.0020	0.0018
Emission Rate:				
pounds/hour	9.0857	11.057	12.361	10.835
pounds/10^6 Btu	0.0046	0.0058	0.0066	0.0057

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	85% Load Fuel Oil			
Date	04/30/00	04/30/00	04/30/00	
Time	0045-0414	0730-1050	1127-1447	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0007	0.0009	0.0008	0.0008
@ Standard Conditions, grains/dscf	0.0023	0.0032	0.0029	0.0028
Emission Rate:				
pounds/hour	14.135	19.395	17.451	16.994
pounds/10^6 Btu	0.0072	0.0102	0.0093	0.0089

TOTAL PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Fuel Factor (dscf/10^6Btu)	9201	9217	9217	
Date	04/28/00	04/30/00	04/30/00	
Time	0140-0509	1532-1903	1950-2317	
Total Particulate Concentration:				
@ Flue Conditions, grains/acf	0.0018	0.0012	0.0013	0.0014
@ Standard Conditions, grains/dscf	0.0063	0.0043	0.0046	0.0051
Total Emission Rate:				
pounds/hour	32.159	22.366	24.707	26.411
pounds/10^6 Btu	0.0200	0.0136	0.0149	0.0162
Visible Emissions, % Opacity	0.0	0.0	0.0	0.0
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	2,101,199	2,180,929	2,209,789	2,163,972
@ Standard Conditions, dscfm	592,415	611,930	620,270	608,205
Average Gas Temperature, °F	1,143	1,171	1,171	1,162
Average Gas Velocity, ft/sec	137.620	142.842	144.732	141.731
Flue Gas Moisture, percent by volume	11.7	11.5	11.5	11.6
Average Flue Pressure, in. Hg	29.00	29.31	29.31	
Barometric Pressure, in. Hg	29.10	29.41	29.41	
Average %CO_2 by volume, dry basis	6.50	6.40	6.40	6.43
Average %O_2 by volume, dry basis	12.20	12.30	12.30	12.27
Dry Molecular Wt. of Gas, lb/lb-mole	29.528	29.516	29.516	
Gas Sample Volume, dscf	95.749	98.423	100.608	
Isokinetic Variance	103.3	102.8	103.7	

FILTERABLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Date	04/28/00	04/30/00	04/30/00	
Time	0140-0509	1532-1903	1950-2317	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0006	0.0005	0.0006	0.0006
@ Standard Conditions, grains/dscf	0.0021	0.0018	0.0020	0.0020
Emission Rate:				
pounds/hour	10.802	9.456	10.845	10.368
pounds/10^6 Btu	0.0067	0.0058	0.0065	0.0063

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Unit 1			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	70% Load Fuel Oil			
Date	04/28/00	04/30/00	04/30/00	
Time	0140-0509	1532-1903	1950-2317	
Particulate Concentration: Method 202 (Back Half Only)				
@ Flue Conditions, grains/acf	0.0012	0.0007	0.0007	0.0009
@ Standard Conditions, grains/dscf	0.0042	0.0025	0.0026	0.0031
Emission Rate:				
pounds/hour	21.358	12.910	13.862	16.043
pounds/10^6 Btu	0.0133	0.0079	0.0083	0.0098

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2.0 SUMMARY OF RESULTS

During this test program, three (3) particulate and gaseous emission tests were performed under each fuel condition.

The following table summarizes the test results under each fuel firing.

Parameter	Natural Gas with Duct Burner		Fuel Oil with Duct Burner	
	Allowable	Actual	Allowable	Actual
M5 + M202 (Less Aqueous Fraction)	10.7	5.87	57.5	7.56
PM_{10} + M202	10.7	5.70	57.5	31.90
NO_x (lbs/hr)	36.5	26.22	139.9	115.08
CO (lbs/hr)	20.7	0.56	38.0	0.0
VOC (lbs/hr)	19.0	3.13	20.9	1.08
H_2SO_4 (lbs/hr)	0.37	0.212	29.3	11.39
Opacity (%)	<20	0	<20	0
SO_2 (lbs/hr)	1.3	1.1	59.6	50.35

Complete test results summaries are tabulated and can be found on pages 11 through 26.

3.0 DISCUSSION OF RESULTS

Particulate emissions were determined by adding the Method 5 front half to the Method 202 back half (minus the aqueous fraction). Particulate emissions were also determined by adding the Method 201A front half to the Method 202 back half.

Plant data was recorded by plant personnel and is appended in this report.

Manufacturer's data for the diesel fire pump, emergency diesel generator and the fuel gas heaters is appended in this report.

Also appended in this report is opacity data from the auxiliary boiler. These tests were run on September 28 and 29, 1997 using the opacity monitor system.

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set up specifications. The PM_{10} emissions were calculated from the gravimetric analyses of the cyclone exit acetone wash and in-stack filter.

4.6 Condensable Particulate Matter Determination

This method applies to the determination of condensable particulate matter (CPM) emission from stationary sources. It is intended to represent condensable matter as material that condenses after passing through an in-stack filter and as measured by this method. (Note: The filter catch can be analyzed according to Methods 5 and 17, 40CFR60, Appendix A procedures.) This method was used in conjunction with Method 201A (Appendix M, 40CFR51) because the probes were glass-lined.

The CPM was collected in the impinger portion of 201A (Appendix M, 40CFR51) type sampling train. The impinger contents were immediately purged after the run with nitrogen (N_2) to remove dissolved sulfur dioxide (SO_2) gases from the impinger contents. The impinger solution was then extracted with methylene chloride ($MeCl_2$). The organic and aqueous fractions were then taken to dryness and the residues weighed. A correction was made for any sulfates or chlorides present in the impingers. The total of both fractions represents the CPM.

4.7 Nitrogen Oxides (NO_x) Determination

Method 7E, 40CFR60, was used for determining nitrogen oxides (NO_x) emissions from the test location. A gas sample was continuously extracted from the gas stream through a heated sampling probe and a gas conditioning system to remove moisture. A portion of the sample stream was conveyed via a sampling line to gas analyzers for determination of NO_x content. Prior to emissions sampling, the nitric oxide (NO)/NO_x analyzer was zeroed and calibrated. High-range, mid-range, and zero gases were introduced into the NO_x sampling system.

The sample gas manifold was then adjusted for emissions sampling. In the course of the testing, the zeroes were checked and mid-range NO_x gas was introduced into the sampling system to check calibration.

The chemiluminescent reaction of NO and ozone (O_3) provides the basis for this instrument operation. Specifically:

$$NO + O_3 \rightarrow NO_2 + O_2 + h_\nu$$

where h_ν = light

Light emission results when electronically excited nitrogen dioxide (NO_2) molecules revert to their ground state. To measure NO concentrations, the gas sample to be analyzed was

Blondie

PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/25/97	
Time	1130-1341	1431-1650	1744-1957	
Particulate Concentration: Method 5 (Front Half Only)				
@ Flue Conditions, grains/acf	0.0005	0.0007	0.0008	0.0007
@ Standard Conditions, grains/dscf	0.0007	0.0010	0.0012	0.0010
Emission Rate:				
pounds/hour	4.733	6.361	7.635	6.243
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	1,056,688	1,086,553	1,075,494	1,072,912
@ Standard Conditions, dscfm	746,339	773,902	767,699	762,647
Average Gas Temperature, °F	200	200	199	200
Average Gas Velocity, ft/sec	69.209	71.165	70.440	70.271
Flue Gas Moisture, percent by volume	8.5	7.7	7.6	7.9
Average Flue Pressure, in. Hg	28.87	28.87	28.87	
Barometric Pressure, in. Hg	28.95	28.95	28.95	
Average $\%CO_2$ by volume, dry basis	5.9	5.9	5.9	
Average $\%O_2$ by volume, dry basis	12.3	12.5	12.4	
Dry Molecular Wt. of Gas, lb/lb-mole	29.436	29.444	29.440	
Gas Sample Volume, dscf	104.380	108.460	106.856	
Isokinetic Variance	97.7	97.9	97.2	
Visual Emissions Readings, %	0.0	0.0	0.0	0.0
Fuel Flow, gpm	178.6	177.7	179.2	178.5
Ammonia Flow, lbs/hr	193.6	253.9	227.7	225.1
Duct Burner Flow, KSCFH	238.7	226.5	220.0	228.4

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CONDENSABLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/26/97	
Time	1145-1617	1703-2126	0812-1226	
Particulate Concentration: Method 202 Less Aqueous Fraction Associated with Method 201A Tests (Back Half Only)				
@ Flue Conditions, grains/acf	0.0000	0.0000	0.0004	0.0001
@ Standard Conditions, grains/dscf	0.0000	0.0000	0.0006	0.0002
Emission Rate:				
pounds/hour	0.000	0.000	3.941	1.314

TOTAL PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/26/97	
Time	1145-1617	1703-2126	0812-1226	
Particulate Concentration: Method 5A/202 (Front and Back Half)				
@ Flue Conditions, grains/acf	0.0005	0.0007	0.0012	0.0008
@ Standard Conditions, grains/dscf	0.0007	0.0010	0.0018	0.0012
Emission Rate:				
pounds/hour	4.733	6.361	11.576	7.557

Blondie

PARTICULATE TEST RESULTS SUMMARY				
Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/26/97	
Time	1145-1617	1703-2126	0812-1226	
Particulate Concentration: Method 201A (PM_{10} Only)				
@ Flue Conditions, grains/acf	0.0004	0.0006	0.0005	0.0005
@ Standard Conditions, grains/dscf	0.0005	0.0009	0.0007	0.0007
Emission Rate:				
pounds/hour	3.502	5.581	4.986	4.690
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	1,075,417	1,090,374	1,112,609	1,092,800
@ Standard Conditions, dscfm	758,920	758,578	792,743	770,080
Average Gas Temperature, °F	198	197	194	196
Average Gas Velocity, ft/sec	70.435	71.415	72.871	71.574
Flue Gas Moisture, percent by volume	8.8	10.2	8.6	9.2
Average Flue Pressure, in. Hg	28.85	28.85	28.89	
Barometric Pressure, in. Hg	28.93	28.93	28.97	
Average $\%CO_2$ by volume, dry basis	5.9	5.9	5.9	
Average $\%O_2$ by volume, dry basis	12.4	12.4	12.4	
Dry Molecular Wt. of Gas, lb/lb-mole	29.440	29.440	29.440	
Gas Sample Volume, dscf	91.162	89.943	90.444	
Isokinetic Variance	90.8	89.7	86.3	

Blondie

CONDENSABLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/26/97	
Time	1145-1617	1703-2126	0812-1226	
Particulate Concentration: Method 202 Associated with Method 201A Tests (Back Half Only)				
@ Flue Conditions: grains/acf	0.0047	0.0013	0.0027	0.0029
@ Standard Conditions, grains/dscf	0.0067	0.0019	0.0039	0.0042
Emission Rate:				
pounds/hour	43.271	12.158	26.199	27.209

TOTAL PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil with Duct Burner			
Date	09/25/97	09/25/97	09/26/97	
Time	1145-1617	1703-2126	0812-1226	
Particulate Concentration: Method 201A/202 (Front and Back Half)				
@ Flue Conditions, grains/acf	0.0051	0.0019	0.0032	0.0034
@ Standard Conditions, grains/dscf	0.0072	0.0028	0.0036	0.0045
Emission Rate:				
pounds/hour	46.773	17.739	31.185	31.899

[redacted] [redacted]

Blondie

PETROLEUM SPECIALIST LAB

Rt. 2, Box 288 Floresville, Texas 78114 Telephone 830-216-3113 Fax 830-393-8101

[redacted]

03 October 97

Report # 6293

Sample I.D.: Cottage Grove

TESTS REQUESTED	METHOD	UNITS/COND	RESULT
FLASH POINT	D93	°F	139
VAPOR PRESSURE	D323	PSI @100°F	0.61
POUR POINT	D97	°F	*
CLOUD POINT	D2500	°F	*
CARBON RESIDUE	D524	% on 10% Residue	0.05
WATER & SEDIMENT	D1796	PERCENT VOL	<0.05
WATER CONTENT	D1744	PPM	57
PARTICULATES	D2276	MG/L	*
WATER REACTION	D1094	RATING	1b
		INTERFACE	2
ASH	D482	MASS %	*
DISTILLATION	D86	°F AT IBP	336.7
		°F AT 10 PCT REC	385.1
		°F AT 20 PCT REC	399.1
		°F AT 30 PCT REC	413.2
		°F AT 40 PCT REC	424.0
		°F AT 50 PCT REC	436.4
		°F AT 60 PCT REC	449.7
		°F AT 70 PCT REC	464.5
		°F AT 80 PCT REC	482.5
		°F AT 90 PCT REC	506.8
		°F AT FBP	557.8
		PERCENT RECOVERY	98.9
		PERCENT RESIDUE	1.0
		PERCENT LOSS	0.1
API GRAVITY	D287	DEG API	38.7
JF TOT @245°C	D3241	PRESSURE DROP MM	0.0
		TUBE DEPOSIT RATING	#1
HEATING VALUE HHV	D240	BTU/lb	19,720
HEATING VALUE LHV	D240	BTU/lb	18,555
MICROBIAL GROWTH	KIT	COLONIES	<10²
PEROXIDES	D3703	MGS/KG	*
EXISTENT GUM	D381	MG/100ML	7.2
ACIDITY	D3242	MG KOH/GM	0.013
BROMINE INDEX	D2710	#	*
NITROGEN 3 RUN AVE	D4629	MG/KM a	*
SULFUR 3 RUN AVE	D4294	WT%	0.0372
AROMATICS	D1319	PERCENT VOL	22.98
OLEFINS	D1319	PERCENT VOL	2.73
ANILINE POINT	D611	°F	136.9
SMOKE POINT	D1322	MM	16.5
COPPER CORROSION	D130	CLASSIFICATION	*
LUMINOMETER	D1740	#	33.0
VISCOSITY	D445	CENTISTOKES	1.8

This product meets the specifications for the following fuels:

Tests Conducted By: [signature] Chris Taylor

Blondie

[redacted]

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2.0 SUMMARY OF RESULTS

During this test program, three (3) particulate and gaseous emission tests were performed under each fuel condition.

The following table summarizes the test results under each fuel firing. The average emission limits for particulates, NHC, H_2SO_4 and SO_2 were adjusted for ambient temperatures.

Parameter	Natural Gas		Fuel Oil	
	Emission Rate	Average Limit	Emission Rate	Average Limit
Particulate including [redacted] back half at ambient temperatures (lbs/hr)	8.68	9.80	37.67	62.24
NO_X ppm corrected to 15% O_2	3.91	4.5	14.66	16.0
CO ppm corrected to 15% O_2	9.53	42.2	17.02	67.8
NHC ppm as Carbon at ambient temperatures (lbs/hr)	0.14	14.77	0.00	8.92
H_2SO_4 at ambient temperatures (lbs/hr)	0.00	0.36	2.28	14.80
VE%	0	10	0	10
SO_2 at ambient temperatures (lbs/hr)	<0.815	1.0	54.00	88.62

The initial natural gas analysis may have been up to ±50% relative error in the detection limit pe[redacted] Inc. due to the low levels of SO_2 present in the sample.

A second natural gas analysis was performed with a lower detection limit to determine the SO_2 emissions. Both laboratory analysis sheets are appended in this report.

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Complete test results summaries are tabulated and can be found on pages 11 through 23.

3.0 DISCUSSION OF RESULTS

Ambient air Method 5 particulate samples were collected each day of sampling. The condensible portion of the analysis was subtracted from the particulate test results from the stack as [redacted]. Particulate test No. 3 did not pass the post test leak check and was not included in the test results, an additional test run was performed.

Plant data was recorded and is appended.

4.0 TEST PROCEDURES

All testing, sampling, analytical, and calibration procedures used for this test program were performed as described in the *Code of Federal Regulations*, Title 40, Part 60, Appendix A (40CFR60). Methods 1-5, 7E, 8, 9, 10, 18, 20 and 25A and the latest revisions thereof. Where applicable, the *Quality Assurance Handbook for Air Pollution Measurement Systems*, Volume III, Stationary Source Specific Methods, United States Environmental Protection Agency (USEPA) 600/4-77-027b was used to determine the precise procedures.

4.1 Volumetric Flowrate Determination

In order to determine the emission rate on a lbs/hr basis, the stack gas velocity and volumetric flowrate were determined using reference Method 2.

Velocity pressures were determined by traversing the test location with an S-type pitot tube. Temperatures were measured using a K-type thermocouple with a calibrated digital temperature indicator. The molecular weight and moisture content of the gases were determined to permit the calculation of the volumetric flowrate. Sampling points utilized were determined using Method 1, 40CFR60.

4.2 Oxygen (O_2)/Carbon Dioxide (CO_2) Determination

Oxygen (O_2) and carbon dioxide (CO_2) gas contents were determined in accordance with Method 3, 40CFR60. This method analyzed samples collected in a grab or integrated manner using a Hays Orsat gas analyzer. Several gas extractions were performed during each test run to ensure a stable reading. Mandatory leak checks were

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performed prior to and following each use. Chemicals are changed frequently and inspected for reactivity prior to each use.

4.3 Oxygen (O_2) Determination

An oxygen (O_2) analyzer was used to determine O_2 concentrations in the stack gas in accordance with Method 3A, 40CFR60. This instrument has a paramagnetic-based detector and operates in the range of 0-25% O_2. High-range calibrations were performed using Protocol One gas at 20.9% O_2. Zero nitrogen (low ppm pollutants in balance nitrogen calibration gases were used as zero gas on these analyzers) was introduced during other instrument calibrations to check instrument zero and a mid-range %O_2 level in balance nitrogen was also introduced. Mid-range calibrations were performed using certified standard gas prior to and between each test run.

4.4 Carbon Dioxide (CO_2) Determination

A carbon dioxide (CO_2) analyzer was used to determine CO_2 concentrations in the stack gas in accordance with Method 3A, 40CFR60. This instrument has a nondispersive infrared-based detector and operates in a range of 0-20% CO_2. A high- and mid-range calibration was performed using certified standard gases, and non-CO_2-containing gas mixtures were used for the CO_2 zero. Mid-range and zero calibrations were performed prior to and between each test run.

4.5 Particulate Determination

A total of 24 test points were sampled using 4 ports at the combustion turbine stack test location. A single point test was also performed at the ambient air intake location.

The particulate sampling train was manufactured by Nutech Corporation of Durham, North Carolina and meets all specifications required by Method 5. A 8-foot glass-lined probe was used. Drawings depicting the sampling ports, test point locations, and sampling trains are appended to this report. Velocity pressures were determined simultaneously during sampling with a calibrated S-type pitot tube and inclined manometer. All temperatures were measured using K-type thermocouples with calibrated digital temperature indicators.

The filter media were Whatman 934-AH glass microfibre filters exhibiting a ≥ 99.99% efficiency on 0.3 micron DOP smoke particles in accordance with ASTM Standard Method D-2986-71. All sample contact surfaces of the train were washed with HPLC reagent-grade acetone. These washes were placed in sealed and marked containers for analysis.

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All sample recovery was performed at the test site by the test crew. All final particulate sample analyses were performed by [redacted]rsonnel at the [redacted] laboratory in [redacted] including [redacted]back half requirements. Copies of all sample analysis sheets, explanations of nomenclature and calculations, and raw field data sheets are appended to this report.

4.6 Nitrogen Oxides (NO_x) Determination

Method 7E, 40CFR60, was used for determining nitrogen oxides (NO_x) emissions from the test location. A gas sample was continuously extracted from the gas stream through a heated sampling probe and a gas conditioning system to remove moisture. A portion of the sample stream was conveyed via a sampling line to gas analyzers for determination of NO_x content. Prior to emissions sampling, the nitric oxide (NO)/NO_x analyzer was zeroed and calibrated. High-range, mid-range, and zero gases were introduced into the NO_x sampling system.

The sample gas manifold was then adjusted for emissions sampling. In the course of the testing, the zeroes were checked and mid-range NO_x gas was introduced into the sampling system to check calibration.

The chemiluminescent reaction of NO and ozone (O_3) provides the basis for this instrument operation. Specifically:

$$NO + O_3 \rightarrow NO_2 + O_2 + h_\upsilon$$

$$\text{where } h_\upsilon = \text{light}$$

Light emission results when electronically excited nitrogen dioxide (NO_2) molecules revert to their ground state. To measure NO concentrations, the gas sample to be analyzed was blended with O_3 in a reaction chamber. The resulting chemiluminescence was monitored through an optical filter by a high-sensitivity photomultiplier positioned at one end of the chamber. The filter/photomultiplier combination responds to light in a narrow-wavelength band unique to the above reaction (hence, no interference). The output from the photomultiplier is linearly proportional to the NO concentration.

To measure NO_x concentrations (i.e., NO plus NO_2), the sample gas flow was diverted through a NO_2-to-NO converter. The chemiluminescent response in the reaction chamber to the converted effluent is linearly proportional to the NO_x concentration entering the converter. The instrument was operated in the NO_x mode during all tests and calibrations.

BUGS

Plant[redacted]	Source: Ambient Air			
Test Run Number	1	2	3	Average
Test Location	Ambient Air Intake			
Date	06/24/97	06/24/97	06/25/97	
Time	0919-1519	1640-2040	1252-1658	
Particulate Concentration: Back Half Only				
@ Standard Conditions, grains/dscf	0.0004	0.0012	0.0007	0.00077
Average Gas Temperature, °F	90.8	84.5	86.3	87.2
Flue Gas Moisture, percent by volume	2.50	2.40	1.80	2.23
Barometric Pressure, in. Hg	29.15	28.94	29.08	
Average % CO_2 by volume, dry basis	0.0	0.0	0.0	0.0
Average % O_2 by volume, dry basis	20.9	20.9	20.9	20.9
Gas Sample Volume, dscf	249.090	160.937	162.954	

BUGS

Plant: [redacted]	Source: Combustion Turbine			
Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil			
Date	07/07/97	07/07/97	07/07/97	
Time	0903-1231	1357-1733	1834-2159	
Particulate Concentration: Total Particulate				
@ Flue Conditions, grains/acf	0.0041	0.0026	0.0038	0.0035
@ Standard Conditions, grains/dscf	0.0069	0.0043	0.0064	0.0059
@ Standard Conditions less ambient correction. grains/dscf	0.00655	0.00395	0.00605	0.00552
Emission Rate:				
pounds/hour corrected for ambient back half	45.518	26.852	40.641	37.670
Average Gas Volumetric Flow Rate:				
@ Flue Conditions, acfm	1,345.648	1,314,807	1,298.079	1,319,511
@ Standard Conditions, dscfm	810,751	793,098	783,713	795,854
Average Gas Temperature, °F	311	309	308	309
Average Gas Velocity, ft/sec	88.134	86.114	85.019	86.422
Flue Gas Moisture, percent by volume	9.5	9.6	9.7	9.6
Average Flue Pressure, in. Hg	29.09	29.08	29.08	
Barometric Pressure, in. Hg	29.16	29.16	29.16	
Average % CO_2 by volume, dry basis	5.5	5.4	5.3	
Average % O_2 by volume, dry basis	13.2	13.2	13.3	
% Excess Air	159.744	159.236	162.401	
Dry Molecular Wt. of Gas, lb/lb mole	29.408	29.392	29.380	
Gas Sample Volume, dscf	190.110	186.782	182.992	
Isokinetic Variance	98.2	98.6	97.7	
Opacity, %	0	0	0	0

[redacted] [redacted]

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FRONT HALF PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted] Source: Combustion Turbine

Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil			
Date	07/07/97	07/07/97	07/07/97	
Time	0903-1231	1357-1733	1834-2159	
Particulate Concentration: Front Half				
@ Flue Conditions, grains/acf	0.0005	0.0002	0.0002	0.0003
@ Standard Conditions, grains/dscf	0.0008	0.0004	0.0003	0.0005
Emission Rate:				
pounds/hour	5.527	2.752	2.096	3.458

CONDENSIBLE PARTICULATE TEST RESULTS SUMMARY

Plant: [redacted] Source: Combustion Turbine

Test Run Number	1	2	3	Average
Test Location	Stack			
Source Condition	Full Load - Fuel Oil			
Date	07/07/97	07/07/97	07/07/97	
Time	0903-1231	1357-1733	1834-2159	
Particulate Concentration: Back Half				
@ Flue Conditions, grains/acf	0.0037	0.0024	0.0037	0.0033
@ Standard Conditions, grains/dscf	0.0061	0.0039	0.0060	0.0053
Emission Rate:				
pounds/hour	42.133	26.731	40.613	36.492

BU6

Plant: [redacted]	Source: Ambient Air		
Test Run Number	1	2	Average
Test Location	Ambient Air Intake		
Date	07/07/97	07/97/97	
Time	0815-1315	1400-1930	
Particulate Concentration: Back Half Only			
@ Standard Conditions, grains/dscf	0.0006	0.0001	0.00035
Average Gas Temperature, °F	83	84	84
Flue Gas Moisture, percent by volume	1.0	0.9	1.0
Barometric Pressure, in. Hg	29.32	29.32	
Average $\%CO_2$ by volume, dry basis	0.0	0.0	0.0
Average $\%O_2$ by volume, dry basis	20.9	20.9	20.9
Gas Sample Volume, dscf	214.372	262.546	

BUGS

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EMISSION TESTS AT STEWART & STEVENSON OPERATIONS, INC. COGENERATION FACILITY SACRAMENTO, CA

HRSG-A
March 10 and 11, 1998

Prepared for:

Stewart & Stevenson Operations, Inc.
5000 83rd Street
Sacramento, California 95826
(916) 381-2921

April 1998

Prepared by:

Steiner Environmental, Inc.
4930 Boylan Street
Bakersfield, California 93308
(805) 334-1102

PS-98-3977/Project 7872-98

TABLE OF CONTENTS

SECTION 1

INTRODUCTION

At the request of Stewart & Stevenson Operations, Inc., Steiner Environmental, Inc. conducted emission tests on the HRSG stack of gas turbine A at the cogeneration plant located next to the Proctor & Gamble Plant in Sacramento. The purpose of these tests was to determine the relative accuracy of the CERMS and to determine compliance with the limitations contained in the ATC (Final Determination of Compliance) issued by the Sacramento Metropolitan AQMD. These tests were conducted on March 10 and 11 , 1998.

The Sacramento Cogeneration Authority (SCA), which is comprised of the Sacramento Municipal Utility District (SMUD) and the Sacramento Municipal Utility District Financing Authority, has built a 171-MW peak load cogeneration plant adjacent to the Proctor & Gamble manufacturing plant in Sacramento, California. The cogeneration plant consists of two natural gas fired, combined cycle gas turbines and a single natural gas fired auxiliary boiler.

The gas turbines are General Electric LM6000 units, each rated at 421.4 MMBtu/hr. Each turbine drives a 42 MW electric generator. The inlet air to each turbine is cooled with chilled water provided to cooling coils in the inlet filter housing during the hot summer months. Water injection into each turbine is used for partial NO_x control.

The hot turbine exhaust gases (~1,036,000 lb/hr at 844°F) enter a heat recovery steam generator (HRSG) equipped with a duct burner rated at 75.39 MMBtu/hr. Both HRSG's are capable of providing enough steam to drive a steam turbine and produce an additional 28 MW without the duct burner in operation. With the duct burners in operation, an additional 43.3 MW of power may be generated. The HRSG is equipped with an oxidation catalyst to reduce CO (90%) and ROC (10%) emissions. The HRSG also contains a selective catalytic reduction (SCR) unit for additional NO_x control. Approximately 10 gal/hr of aqueous ammonia is injected onto the catalyst to reduce NO_x to less than 5 ppm at 15-percent O_2.

The exhaust gases from the HRSG's are discharged into separate stacks and then into the atmosphere. Each stack is equipped with a single point, dry, extractive CERMS to continuously monitor NO_x, CO and O_2 emissions.

For compliance demonstration, triplicate tests were conducted for PM_{10}, SO_x, NO_X, CO, NH_3, and hydrocarbon to determine compliance. Three 120-minute tests were done using EPA Method 5/8 to measure PM_{10} (assume all PM is PM_{10}) at 100-percent load with the duct burners on. At the same time, three 120-minute tests were conducted to measure NO_X, CO_2, O_2 and CO using EPA Methods 7E, 3A and 10.

Three 120-minute NH_3 slip tests were conducted using BAAQMD Method ST-1B. Three 120-minute EPA Method 18 tests were also be done to measure ROC.

At 50-percent load, with no duct burners in operation, triplicate tests for NO_x, CO and ROC were performed. Triplicate 60-minute tests for NO_x, CO_2, O_2 and CO were done using EPA Methods 7E, 3A and 10. Triplicate 60-minute tests were done for flowrate and H_2O using EPA Methods 2/4 and for ROC using EPA Method 18.

During the PM_{10} tests at 100-percent load, a single 7-hour EPA Method 5/8 test was performed on the inlet air entering the turbine to measure PM_{10} (assumes all PM is PM_{10}) and SO_x.

For the relative accuracy tests, nine 32-minute tests for NO_x, CO_2, O_2 and CO were conducted using EPA Methods 7E, 3A and 10. Nine 32-minute flowrate and H_2O tests were conducted using EPA Methods 2/4.

A sample of the natural gas fired in the turbine and duct burners was collected and analyzed for CHNOS, moisture, specific gravity and Btu using ASTM Methods.

Section 2 presents the test matrix for this program.

SECTION 2

TEST MATRIX

Table 2-1 summarizes the tests performed on HRSG-A on this program. Tables 2-2 to 2-5 present the results of the compliance tests at 50-percent and 100-percent load. Table 2-6 compares the measured emissions with those allowed by the permit. All data are reported at 68°F and 29.92 inches Hg. Tables 2-7 through 2-13 present the relative accuracy test results.

2.1 COMPLIANCE TESTS

Gas turbine A was in compliance with the NO_x, CO and ROC limits at both 50-percent (no duct burners) and 100-percent loads (with duct burners). The turbine was also in compliance with the PM_{10} emission limit at 100 percent load with the duct burners on. The turbine was not in compliance with the SO_x (sulfate plus SO_2) limits in the permit. The measured NH3 slip was also below the permitted limit of 10 ppm at 15-percent O_2.

The ambient SO_x (sulfate plus SO_2) at the inlet of the turbine was <10 percent of the SO_x measured at the HRSG stack and therefore, was not a contributing factor to the SO_x exceeding the limit. The sulfur content of the natural gas is responsible for the SO_x. Detailed fuel sulfur tests were performed at SPA/Campbell Soup cogen and it was clear that the SO_x emission limits were set too low for the sulfur content of the natural gas being consumed by that cogen. The same problem has probably occurred here.

2.2 RELATIVE ACCURACY TESTS

EPA Performance Specifications 2, 3 4 and 6 limit the relative accuracy of NO_x, O_2, CO and flowrate monitors (or flowrate calculations) to ± 20%, ±10% and ±20%. The NO_x analyzer met this criterion on a ppm, ppm @ 15% O_2 and lb/hr basis. The O_2 analyzer met the criteria. The CO analyzer failed the criteria because the CO levels were barely above the detection limit of the analyzer (0.1 ppm). Performance Specification 4 allows low CO emitters to meet a ±5 ppm limit which this CO analyzer met. The flowrae calculation met the ±20% limit.

Section 3 describes the equipment and procedures to be used to conduct these tests.

TABLE 2-1. HRSG-A TEST MATRIX

Date	Test No.	Test Parameter	Test Time	Test Condition
3/10/98	1	NO_x, CO_2, O_2, CO Flowrate/H_2O	0804 - 0845	462.1 MMBtu/hr 44.31 MW
	2	NO_x, CO_2, O_2, CO Flowrate/H_2O	0903 - 0942	
	3	NO_x, CO_2, O_2, CO Flowrate/H_2O	0955 - 1035	
	4	NO_x, CO_2, O_2, CO Flowrate/H_2O	1048 - 1125	
	5	NO_x, CO_2, O_2, CO Flowrate/H_2O	1138 - 1215	
	6	NO_x, CO_2, O_2, CO Flowrate/H_2O	1227 - 1304	
	7	NO_x, CO_2, O_2, CO Flowrate/H_2O	1318 - 1355	
	8	NO_x, CO_2, O_2, CO Flowrate/H_2O	1411 - 1442	
	9	NO_x, CO_2, O_2, CO Flowrate/H_2O	1503 - 1541	
3/11/98	1	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	0702 - 0809	313.8 MMBtu/hr 29.83 MW
	2	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	0822 - 0930	
	3	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	0947 - 1055	

TABLE 2-1. HRSG-A TEST MATRIX (Concluded)

Date	Test No.	Test Parameter	Test Time	Test Condition
3/11/98	1	PM_{10}, Sulfate, SO_2 NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	1327 - 1541	456.9 MMBtu/hr 44.1 MW
	2	PM_{10}, Sulfate, SO_2 NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	1616 - 1830	
	3	PM_{10}, Sulfate, SO_2 NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	1901 - 2114	

TABLE 2-2

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - A

Date : MAR 11,1998

Test Number	1	2	3	Average
Test Condition		50% LOAD		
Barometric Pressure (in. Hg)	30.00	30.00	30.00	30.00
Stack Pressure (in. Hg)	29.97	29.97	29.97	29.97
Stack Area (ft2)	77.48	77.48	77.48	77.48
Elapsed Sampling Time (min.)	60.0	60.0	60.0	60.0
Volume Gas Sampled (dscf)	48.448	51.315	50.683	50.149
F-Factor	8631.19	8631.19	8631.19	8631.19
GAS DATA				
Average Gas Velocity (fps)	59.86	60.75	60.04	60.21
Average Gas Temperature (dF)	231.50	231.50	230.88	231.29
Gas Flowrate (dscfm)	196588	199516	197606	197903
Gas Analysis (Volume %)				
Carbon Dioxide, dry	3.18	3.17	3.17	3.17
Oxygen, dry	15.53	15.43	15.40	15.45
Water	7.63	7.63	7.51	7.59
EMISSION CONCENTRATION				
CO (ppm)	0.29	0.29	0.29	0.29
NOx (ppm)	2.43	3.33	3.37	3.04
>C1 HC (ppm)	0.00	1.08	0.00	0.36
EMISSION RATE - lb/hr				
CO	0.25	0.25	0.25	0.25
NOx	3.42	4.76	4.77	4.32
>C1 HC	0.00	0.54	0.00	0.18
EMISSION FACTOR - lb/MMBtu				
CO	0.0007	0.0007	0.0007	0.0007
NOx	0.0098	0.0131	0.0132	0.0120
>C1 HC	0.0000	0.0015	0.0000	0.0005
EMISSION CONCENTRATION - @ 15% O2				
CO	0.32	0.31	0.31	0.31
NOx	2.67	3.59	3.62	3.29
>C1 HC	0.00	1.16	0.00	0.39

TABLE 2-3

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - A   Date : MAR 11,1998

Test Number	1	2	3	Average
Test Condition		100% LOAD		
Barometric Pressure (in. Hg)	30.00	29.90	29.90	29.93
Stack Pressure (in. Hg)	29.96	29.86	29.86	29.89
Stack Area (ft2)	77.48	77.48	77.48	77.48
Elapsed Sampling Time (min.)	120.0	120.0	120.0	120.0
Volume Gas Sampled (dscf)	109.889	110.106	110.218	110.071
F-Factor	8631.19	8631.19	8631.19	8631.19
GAS DATA				
Average Gas Velocity (fps)	68.91	68.65	68.75	68.77
Average Gas Temperature (dF)	226.38	226.00	227.13	226.50
Gas Flowrate (dscfm)	224778	227096	223231	225035
Gas Analysis (Volume %)				
Carbon Dioxide, dry	4.19	4.20	4.19	4.19
Oxygen, dry	13.74	13.65	13.74	13.71
Water	8.90	7.35	8.92	8.39
EMISSION CONCENTRATION				
Filterable Particulate (gr/dscf)	0.0007	0.0009	0.0004	0.0007
Total Particulate (gr/dscf)	0.0010	0.0010	0.0005	0.0008
Total Sulfate (gr/dscf)	0.0003	0.0003	0.0003	0.0003
CO (ppm)	0.41	0.37	0.32	0.37
SO2 (ppm)	0.01	0.01	0.01	0.01
NOx (ppm)	5.00	4.91	4.75	4.89
>C1 HC (ppm)	0.00	1.20	1.26	0.82
EMISSION RATE - lb/hr				
Filterable Particulate	1.32	1.66	0.81	1.26
Total Particulate	1.85	2.01	1.05	1.64
Total Sulfate	0.64	0.55	0.48	0.56
CO	0.40	0.37	0.31	0.36
SO2	0.03	0.03	0.03	0.03
NOx	8.05	7.99	7.60	7.88
>C1 HC	0.00	0.68	0.70	0.46
EMISSION FACTOR - lb/MMBtu				
Filterable Particulate	0.0025	0.0030	0.0015	0.0023
Total Particulate	0.0035	0.0037	0.0020	0.0030
Total Sulfate	0.0012	0.0010	0.0009	0.0010
CO	0.0008	0.0007	0.0006	0.0007
SO2	0.00005	0.0001	0.0001	0.0001
NOx	0.0150	0.0146	0.0143	0.0146
>C1 HC	0.0000	0.0012	0.0013	0.0009
EMISSION CONCENTRATION - @ 15% O2				
CO	0.34	0.30	0.26	0.30
SO2	0.01	0.01	0.01	0.01
NOx	4.12	4.00	3.91	4.01
>C1 HC	0.00	0.98	1.04	0.67

TABLE 2-4

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON
HRSG - A

Date : MAR 11,1998

Test Number	1	2	3	Average
Test Condition		100% LOAD		
Barometric Pressure (in. Hg)	30.00	30.00	29.90	29.97
Stack Pressure (in. Hg)	29.96	29.96	29.86	29.93
Stack Area (ft2)	77.48	77.48	77.48	77.48
Elapsed Sampling Time (min.)	120.0	120.0	120.0	120.0
Volume Gas Sampled (dscf)	112.084	110.687	111.886	111.552
F-Factor	8631.19	8631.19	8631.19	8631.19
GAS DATA				
Average Gas Velocity (fps)	72.74	73.57	74.11	73.47
Average Gas Temperature (dF)	223.50	222.38	224.00	223.29
Gas Flowrate (dscfm)	236027	239169	239567	238255
Gas Analysis (Volume %)				
Carbon Dioxide, dry	4.19	4.20	4.19	4.19
Oxygen, dry	13.74	13.65	13.74	13.71
Water	9.76	9.74	9.73	9.74
EMISSION CONCENTRATION				
NH3 (ppm)	4.18	5.09	5.22	4.83
EMISSION RATE - lb/hr				
NH3	2.63	3.24	3.33	3.07
EMISSION FACTOR - lb/MMBtu				
NH3	0.0047	0.0056	0.0058	0.0054
EMISSION CONCENTRATION - @ 15% O2				
NH3	3.45	4.14	4.30	3.96

TABLE 2-5

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - A   Date : MAR 11,1998

Test Number	1
Test Condition	AMBIENT
Barometric Pressure (in. Hg)	30.00
Stack Pressure (in. Hg)	
Stack Area (ft2)	
Elapsed Sampling Time (min.)	420.0
Volume Gas Sampled (dscf)	460.822
GAS DATA	
Average Gas Velocity (fps)	
Average Gas Temperature (dF)	
Gas Flowrate (dscfm)	
Gas Analysis (Volume %)	
Carbon Dioxide, dry	0.00
Oxygen, dry	20.90
Water	0.00
EMISSION CONCENTRATION	
Filterable Particulate (gr/dscf)	5.43E-05
Total Particulate (gr/dscf)	7.27E-05
Total Sulfate (gr/dscf)	1.57E-05
SO2 (ppm)	2.26E-03

TABLE 2-6. MEASURED VERSUS ALLOWABLE EMISSIONS

Emission	Measured		Allowable	
	50%	100%	50%[a]	100%[b]
NO_x ppm @ ~~7~~ 15 % O2	3.29	4.01	5.0	5.0
NO_x lb/hr	4.32	7.88	7.7	9.2
CO lb/hr	0.25	0.36	3.6	4.2
ROC lb/hr	0.18	0.46	1.1	1.8
SO_2 lb/hr	--	~~0.92~~ 0.59	--	0.32
PM_{10} lb/hr	--	1.64	--	3.3
NH3 ppm @ 15% O_2	--	3.96	--	10.0

[a]Combined cycle CTG limit
[b]CTG plus duct burner limit

TABLE 2-7

RELATIVE ACCURACY DETERMINATION - O2 (%)

COMPANY :STEWART/STEVENSON DATE : MAR 10,1998

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	14.56	14.83	-0.27
2	14.41	14.80	-0.39
3	14.43	14.79	-0.36
4	14.40	14.79	-0.39
5	14.46	14.78	-0.32
6	14.45	14.77	-0.32
7	14.45	14.77	-0.32
8	14.45	14.78	-0.33
9	14.53	14.78	-0.25

* a - Values not used in calculations. b - Values used.

Mean : 14.46

Mean : -0.33
Standard Deviation : 0.05

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.04

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$RA (\%) = [\ |\bar{d}| + |CC| / \overline{RM}\ ] \times 100$ = 2.56

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-8

RELATIVE ACCURACY DETERMINATION - NOx (ppm)

COMPANY :STEWART/STEVENSON DATE : MAR 10,1998

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	4.11	4.55	-0.44
2	4.13	4.58	-0.45
3	4.07	4.58	-0.51
4	4.07	4.58	-0.51
5	4.02	4.57	-0.55
6	4.10	4.63	-0.53
7	4.01	4.63	-0.62
8	4.10	4.67	-0.57
9	4.06	4.64	-0.58

* a - Values not used in calculations. b - Values used.

Mean : 4.07 Mean : 4.60 Mean : -0.53
Standard Deviation : 0.06

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.05

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$$RA(\%) = [\ |\bar{d}| + |CC| / \overline{RM}\ ] \times 100 = 14.24$$

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-9

RELATIVE ACCURACY DETERMINATION - NOx (ppm @ 15% O2)

COMPANY :STEWART/STEVENSON DATE : MAR 10,1998

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	3.82	4.42	-0.60
2	3.75	4.43	-0.68
3	3.71	4.43	-0.72
4	3.69	4.42	-0.73
5	3.68	4.41	-0.73
6	3.75	4.45	-0.70
7	3.67	4.45	-0.78
8	3.75	4.50	-0.75
9	3.76	4.47	-0.71

* a - Values not used in calculations. b - Values used.

Mean : 3.73 Mean : 4.44 Mean : -0.71
Standard Deviation : 0.05

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.04

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 20.10

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-10

RELATIVE ACCURACY DETERMINATION - NOx (lb/hr)

COMPANY :STEWART/STEVENSON DATE : 3/10/98

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	6.98	7.46	-0.48
2	7.11	7.58	-0.47
3	7.07	7.57	-0.50
4	7.03	7.58	-0.55
5	6.88	7.55	-0.67
6	6.99	7.61	-0.62
7	6.92	7.59	-0.67
8	6.91	7.57	-0.66
9	6.97	7.53	-0.56

* a - Values not used in calculations. b - Values used.

Mean : 6.98 Mean : 7.56 Mean : -0.58
Standard Deviation : 0.08

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.06

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 9.16

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-11

RELATIVE ACCURACY DETERMINATION - CO (ppm)

COMPANY :STEWART/STEVENSON   DATE : MAR 10,1998

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	0.20	0.01	0.19
2	0.23	0.02	0.21
3	0.28	0.01	0.27
4	0.30	0.01	0.29
5	0.30	0.01	0.29
6	0.30	0.01	0.29
7	0.31	0.01	0.30
8	0.30	0.01	0.29
9	0.30	0.01	0.29

* a - Values not used in calculations. b - Values used.

Mean : 0.28

Mean : 0.27
Standard Deviation : 0.04

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.03

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 107.14

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-12

RELATIVE ACCURACY DETERMINATION - CO (lb/hr)

COMPANY :STEWART/STEVENSON DATE : 3/10/98

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	0.21	0.01	0.20
2	0.24	0.02	0.22
3	0.30	0.01	0.29
4	0.32	0.01	0.31
5	0.31	0.01	0.30
6	0.31	0.01	0.30
7	0.33	0.01	0.32
8	0.31	0.01	0.30
9	0.31	0.01	0.30

* a - Values not used in calculations. b - Values used.

Mean : 0.29

Mean : 0.28
Standard Deviation : 0.04

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.03

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 105.68

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-13

RELATIVE ACCURACY DETERMINATION - FLOWRATE (kscfh)

COMPANY :STEWART/STEVENSON DATE : 3/10/98

SOURCE :HRSG - A

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	14226.90	13749.83	477.07
2	14419.32	13857.17	562.15
3	14538.72	13837.65	701.07
4	14471.16	13863.69	607.47
5	14323.56	13837.02	486.54
6	14283.36	13777.76	505.60
7	14460.00	13746.95	713.05
8	14118.60	13584.51	534.09
9	14376.54	13600.16	776.38

* a - Values not used in calculations. b - Values used.

Mean : 14357. Mean : 13761. Mean : 595.94
Standard Deviation : 109.93

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 84.50

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 4.74

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

SECTION 3

SAMPLING EQUIPMENT AND PROCEDURES

This section of the source test plan describes the equipment and procedures to be used to conduct the particulate and gaseous tests on this program.

3.1 PRELIMINARY MEASUREMENTS

Before conducting the stack tests a series of preliminary measurements are made to determine:

- The location of the sampling site and the number and location of the sampling points to be used (EPA Method 1)
- The velocity, temperature and pressure of the stack gases (EPA Method 2)
- The composition of the stack gases (EPA Method 3A)
- The moisture content of the stack gases (EPA Method 4)

Using the results of these preliminary measurements and the calibration constants for the sampling train, a series of calculations are made to determine the value of K, a constant, and N_d, ideal nozzle diameter, required to run an isokinetic test according to the equation:

$$\Delta H = \left[\frac{60^2 \, \pi^2 (K_p)^2 (C_p)^2 (1 - B_{wo})^2 \, P_s \, MW_d}{576^2 (K_o)^2 \, MW_s \, P_m} \right] (N_d)^4 \left(\frac{T_m}{T_s} \right) (\Delta P)$$

where

$$K = \left[\frac{60^2\ \pi^2 (K_p)^2 (C_p)^2\ (1 - B_{wo})^2\ P_s\ MW_d}{576^2 (K_o)^2\ MW_s\ P_m}\right]$$

An actual nozzle, whose diameter was as close as possible to the ideal nozzle diameter, was selected for the test. Isokinetic sampling rates for each sampling point in the stack are computed using the equation:

$$\Delta H = (K)(N_d)^4 \left(\frac{T_m}{T_s}\right)(\Delta P)$$

Since K and N_d were known, and remained constant during a test, the only variables were the meter temperatures, the stack gas temperature and the velocity pressure for each sampling point.

3.2 PREPARATION OF THE PM_{10}/SO_X SAMPLING TRAIN

All sampling train components were cleaned in the laboratory (soap and water, tap water rinse, distilled water rinse, and IPA rinse) to eliminate previous contamination. The sampling train components were sealed and transported to the sampling site in a mobile lab. The EPA Method 5/8 equipment used to measure PM_{10} (filterable and condensible particulate counted as PM_{10}) and SO_X consisted of:

- A calibrated 316 stainless steel nozzle for isokinetic sampling
- A heated Pyrex glass sampling probe (6 feet long) equipped with an S-type pitot tube and a thermocouple to measure stack velocity, pressure and temperature

- A heated Pyrex glass filter holder containing a weighed 100-mm Whatman 934 AH glass fiber filter
- A Pyrex glass impinger train in an icebath (impinger 1 containing 100-ml 80% IPA; a Pyrex glass filter holder containing a 47-mm Whatman 934 AH filter; bubbler 2 and impinger 3 each containing 100-ml of 3% H_2O_2; bubbler 4 contains a weighed amount of silica gel)
- An umbilical to connect the probe and sample box to the control module
- A control module containing a vacuum pump, a calibrated dry gas meter and a calibrated orifice meter to measure the pressure, temperature and flowrate throughout the train.

The sampling train was charged in the mobile lab using freshly prepared reagents. Each impinger and its contents was weighed to the nearest 0.1 gm on a calibrated electronic balance. Blanks of all filters and reagents were retained for subsequent analysis. The sampling point locations were marked on the probe using a high-temperature marker. The sampling train was completely assembled and lifted to the sampling site.

3.3 SAMPLING PROCEDURES FOR PM_{10}/SO_X SAMPLING TRAIN

Prior to a test, the sampling train was heated and leak checked at 15-inches Hg to insure leakage was less than 0.02 or 4 percent of the average sampling rate. The S-type pitot tube was also leak checked. The sampling train was installed on the unirail and the probe was inserted into the stack at the farthest point. An isokinetic sampling rate was calculated using an HP-41Cx calculator for each sampling point on the traverse (4 points per traverse, 4 traverses at 90°). Each point was sampled for an equal period of time (7.5

minutes) and all pertinent data were recorded on the data sheet every 7.5 minutes for each point. The probe and sample box were maintained at 250°F throughout the traverse. The gases leaving the impinger train were maintained at <68°F. At the end of a traverse, the probe was withdrawn from the stack and the entire sampling train was transferred intact to the next sampling port. After the final traverse of the stack was completed, the sampling train was withdrawn for the final leak check. This leak check was performed at 15-inches Hg or at the highest vacuum achieved during the test. The S-type pitot tube was also checked at this time. The sampling train was then purged with ambient air for 15-minutes using the highest ΔH measured during the test. After the train was purged, the sample box and impinger train were sealed with aluminum foil and lowered to the mobile lab for sample recovery.

3.4 SAMPLE RECOVERY PROCEDURES FOR PM_{10}/SO_X SAMPLING TRAIN

Sample recovery for the nozzle and probe occurred on the stack. The nozzle and probe were brushed and rinsed three times using ACS reagent grade acetone into a polyethylene sample bottle. Sample recovery for the filter holder and impinger train occurred in the mobile lab. The 100-mm filter was removed from the 4-inch filter holder and sealed in its petri dish. The glass fibers stuck to the gasket were scraped off and put into the petri dish. The probe-to-filter connector and the front half of the 4-inch glass filter holder were brushed and rinsed with acetone into the bottle containing the nozzle and probe wash. Each impinger was removed from the icebath, wiped dry and weighed to the nearest 0.1 gm. The contents of impinger 1 were transferred to a polyethylene sample bottle. The back half of the 4-inch glass filter holder, the glass connectors, impinger 1 and the front half the front half of the 2-inch filter holder were rinsed with 80% IPA into this same bottle. The 47-mm filter from the 2-inch filter holder was sealed in its petri dish. The contents of bubbler 2 and impinger 3 were transferred to a polyethylene sample bottle. The back half of the 2-inch filter holder, bubbler 2, the connector and impinger 3 were rinsed with distilled water into this same bottle. All sample bottles and petri dishes were marked and labeled. A chain-of-custody log was completed and the field data sheet was also labeled with the sample ID numbers. The sampling train was then recharged in preparation for the next test.

3.5 SAMPLING PROCEDURES FOR CONTINUOUS MONITORING

The continuous monitors used in the Steiner Environmental Mobile Monitoring Lab are shown in Table 3-1. Figure 3-1 is a schematic of the continuous monitoring system. The procedures used to continuously monitor stack gases for NO_X, CO_2, O_2 and CO strictly follow EPA Methods 7E, 3A and 10.

Prior to the test program, the CEMS was assembled and leak checked. The sample probe was sealed with a cap and the flow through the individual rotameters was observed. The leak check was successful if the pressure at the analyzer system and the flow through the rotameters all drop to zero. A leak check of the entire CEMS was performed before and after each test to insure no leaks occur during movement of the sample probe from port to port. High range calibration gases (EPA Protocol 1) for NO_X, CO, CO_2 and O_2 were then introduced into each analyzer to calibrate the analyzer and recorder. Once these adjustments were completed, the analyzer calibration error checks were performed. Zero, mid-range and high-range calibration gases were introduced to the gas analyzers. No adjustments were made to the system except those necessary to achieve the proper

TABLE 3-1. CONTINUOUS MONITORING LAB

NO_x CHEMILUMINESCENT ANALYZER – THERMO ELECTRON MODEL 10

Response Time (0-90%)	1.5 sec – NO mode; 1.7 sec – NO_x mode
Zero Drift	Negligible after 1/2 hour warmup
Linearity	±1% of full scale
Accuracy	Derived from the NO or NO_2 calibration gas, ±1% of full scale
Output	0-10 V
Operating Ranges	0-2, 10, 25, 100, 250, 1000, 2500 and 10,000 ppm
Flowrate = 2 scfh	0-2.5

O_2 ANALYZER, FUEL TYPE – TELEDYNE MODEL 326

Response Time (0-90%)	60 seconds
Accuracy	±1% of scale at constant temperatures; ±1% of scale of ±5% of reading, which-ever is greater, over the operating temperature range
Output	0-1 V
Operating Ranges	0-5%, 10%, 25% O_2
Flowrate	2 scfh

CO/CO2 INFRARED - FUJI MODEL ZRH

Response Time (0-90%)	3 seconds
Zero Drift	2%
Span Drift	2%
Linearity	±1%
Resolution	<0.5% full scale
Output	0-1 V CO2; 4-20 mAmp CO
Operating Ranges	5% and 25% CO2; 0,5% and 2.5% CO
Flowrate	1 ±0.5 LPM

CO GAS FILTER CORRELATION – THERMO ELECTRON MODEL 48

Response Time (0-95%)	1 minute
Zero Drift	±0.2 ppm CO
Span Drift	Less than 1% full scale in 24 hours
Linearity	±1% full scale, all ranges
Accuracy	±0.1 ppm CO
Output	0-10 V
Operating Ranges	1, 2, 5, 10, 20, 50, 100, 200, 500, 1000 ppm
Flowrate	.5 - 2 LPM

SO_2 UV ANALYZER –WESTERN RESEARCH MODEL 721A/721AT

Response Time (0-90%)	Less than 60 seconds
Zero Drift	Less than 2% full scale in 24 hours
Linearity	±1% full scale
Accuracy	±2% full scale
Output	0-1 V
Operating Ranges	0-400 ppm/1-1000 ppm for Model 721; 0-100/0-1000 Model 721AT
Flowrate	1 LPM

STRIP CHART RECORDERS (3) – LINSEIS 7025

Pen Response	0.35 seconds Full Scale
Input Spans	1, 2, 5, 10, 20, 50, 100 MV
Zero Set	Stable access entire chart-width ±100%
Accuracy	.35% of Span
Dead Band	.15% of Span
Linearity	25% of Span
Chart Speed	1, 2, 5, 10, 20, 50, 100 cm/min; 1, 2, 5, 10, 20, 50 cm/hr; fast advance 100 cm/min; LED indicator; forward and reverse selector
Recording Pen	Fiber tip pen
Chart Width	250 mm

SCOTSMAN TRAILER

Fully Insulated, 8-ft x 12-ft with A/C and heat

1. Filter 0.6 μ, 99.9999 percent efficient
2. Duct
3. 316 stainless steel probe
4. 3/8-inch, heated (250°F) Teflon
5. Four-pass conditioner-dryer, 316 stainless steel internals
6. 3/8-inch, unheated Teflon
7. Teflon-lined sample pump
8. 3/8-inch unheated Teflon
9. Rotameter
10. 1/4-inch Teflon tubing
11. Calibration gas manifold
12. Calibration gas selector valve
13. Calibration gas cylinders
14. Backpressure regulator
15. Auxiliary analysis port

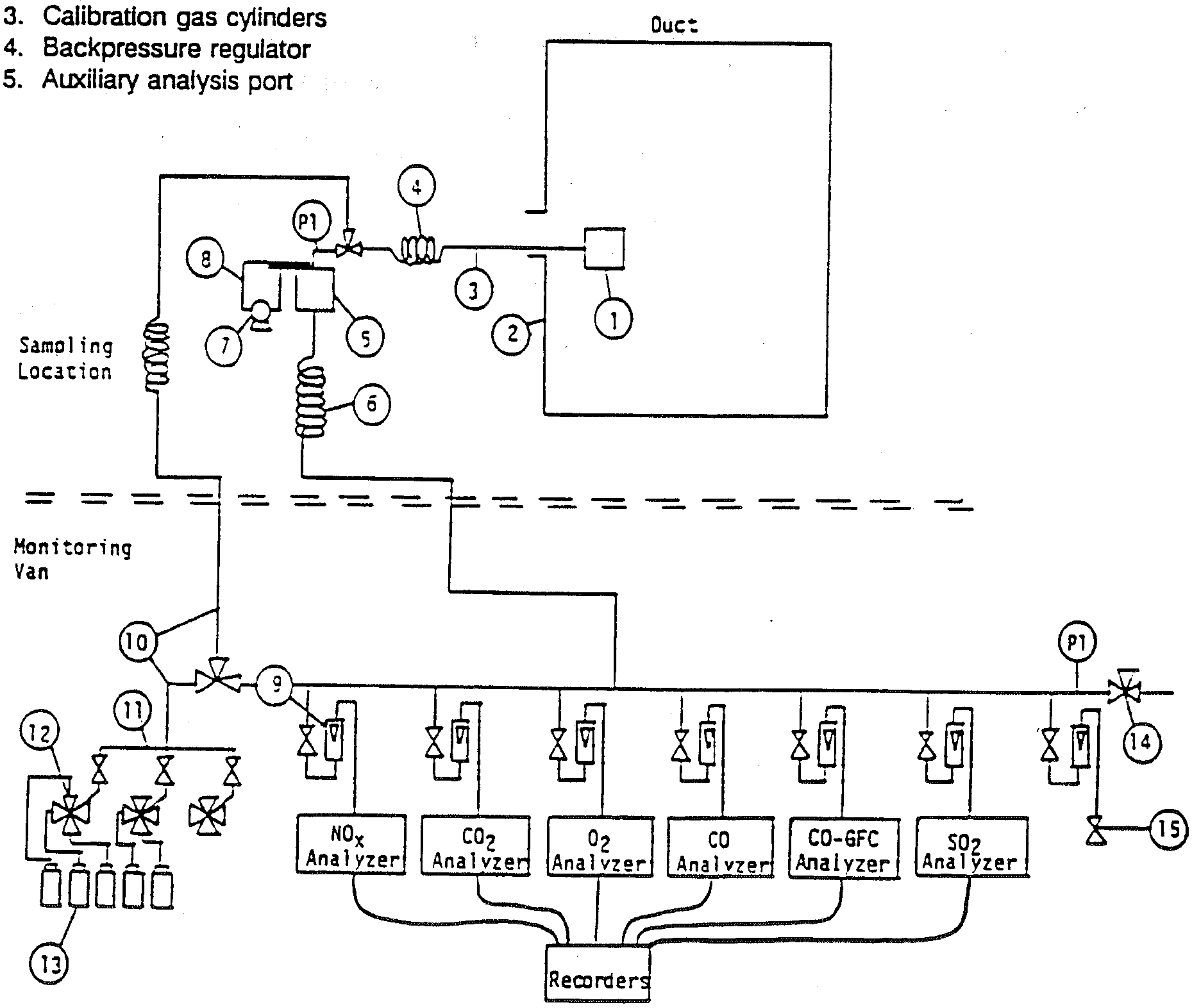

Figure 3-1. Schematic of Continuous Monitoring System.

calibration gas flowrate. The analyzer responses to each calibration gas were recorded on the CEMS field data sheet. If the difference between the gas concentration exhibited by each gas analyzer and the known concentration of each calibration gas, when each calibration gas was introduced directly to each analyzer, was less than ±2% of span for any calibration gas, the check was considered successful. Next, a sampling system bias check was performed by introducing calibration gases at the sample probe. A zero gas and either the mid-range or high-range calibration gas, whichever most closely approximates the stack gas concentrations, was used for this check. No adjustments were made to the system except those necessary to achieve the proper calibration gas flowrate. At the same time, the measurement system response time (95% of gas value) was determined for both the zero and upscale gases. The sampling system bias check was considered valid if the difference between the gas concentrations displayed by the measurement system for the analyzer calibration error check and the sampling system bias check were less than ±5% of span. The CEMS was now ready for the interference response test for NO_X, CO_2, O_2 and CO, which was performed in accordance with Section 5.4 of EPA Method 20. Each high-range calibration gas was introduced into the measurement system and the responses for the individual analyzers were recorded. If the response of each analyzer to the other interfering gases was less than ±2% of span, the system was considered to be interference free. Each reference method run was 32 minutes long.

A NO_X converter check was also performed. A certified gas (7.98 ppm NO_2 in N_2) was introduced into the NO_X analyzer with the analyzer set in the "NO_X" mode until a stable reading was obtained. The converter conversion efficiency was calculated by dividing the measured NO_2 concentration by the certified gas concentration. Testing can proceed if the converter efficiency was greater than 90%. The CEMS was now ready for use.

Sample was taken from the stack (at a single point for the 50- and 100-percent load RATA tests and 16 points for the 100-percent load with duct burners) using a 316 stainless steel probe. A heated Balston filter holder and fiberglass filter (99.9999 percent efficiency retention of 0.6 micron particles) were connected to the outlet of the probe. Sample gas was transported through heated Teflon sample line (maintained at >250°F) by a Teflon-lined diaphragm pump to a 316 stainless steel refrigeration type conditioner (Hankison Model E-4G-SS). The sample gas was passed through the conditioner two separate times under vacuum before entering the pump, then two additional times under pressure. The clean, dry sample gas (approximately 35°F) was then transported to the continuous analyzer system through an unheated Teflon line. A series of flowmeters, valves, and regulators maintain constant flow through the system at a constant pressure.

Calibrations of the continuous analyzers were performed using EPA Protocol 1 calibration gases (±1%) for NO_X, and CO, and NIST certified calibration gases (±1%) for CO_2 and O_2. All pertinent data (date, time, test locations, analyzer range, cal gas value) were recorded on both the data sheets and continuous analyzer strip charts in the field.

At the end of each run, the zero and upscale sampling system bias check was repeated. Zero drift and calibration drift determinations were made by calculating the difference in the measurement system output reading from the initial and final calibration response for both the zero and upscale gases. If the drift in either case was less than ±3%

of span, then the drift was considered acceptable. If the sampling system bias check was less than ±5% of span, the run was considered valid.

The measured gas concentrations were corrected for sampling system bias in accordance with Section 8 equation 6C-1 of EPA Method 6C.

3.6 PREPARATION OF THE NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

All sampling train components were cleaned in the laboratory (soap and water, tap water rinse, distilled water rinse, and IPA rinse) to eliminate previous contamination. The sampling train components were sealed and transported to the sampling site in a mobile lab. The BAAQMD Method ST-1B equipment used to measure NH_3, flowrate and moisture consisted of:

- A straight 316 stainless steel nozzle for constant rate sampling
- A heated Pyrex glass sampling probe (6 feet long) equipped with an S-type pitot tube and a thermocouple to measure stack velocity, pressure and temperature
- A heated sample box containing an untared 100-mm Whatman 934 AH glass fiber filter
- A Pyrex glass impinger train in an icebath (impingers 1 and 2 contained 100-ml 0.1N HCl; bubbler 3 was dry; bubbler 4 contained a weighed amount of silica gel)
- An umbilical to connect the probe and sample box to the control module

- A control module containing a vacuum pump, a calibrated dry gas meter and a calibrated orifice meter to measure the pressure, temperature and flowrate throughout the train.

The sampling train was charged in the mobile lab using freshly prepared reagents. Each impinger and its contents were weighed to the nearest 0.1 gm on a calibrated electronic balance. Blanks of all filters and reagents were retained for subsequent analysis. The sampling point locations were marked on the probe using a high-temperature marker. The sampling train was completely assembled and lifted to the sampling site.

3.7 SAMPLING PROCEDURES FOR NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

Prior to a test, the sampling train was heated and leak checked at 15-inches Hg to insure a leak rate of less than 0.02 cfm or 4 percent of the average sampling rate. The S-type pitot tube was also leak checked. The sampling train was installed on the unirail and the probe was inserted into the stack at the farthest point. A constant sampling rate was calculated using an HP-41CX calculator for each sampling point on the traverse (4 points per traverse; 4 traverses at 90°). Each point was sampled for an equal period of time (7.5 minutes) and all pertinent data were recorded on the data sheet every 7.5 minutes for each point. The probe and sample box were maintained at 250°F throughout the traverse. The gases leaving the impinger train were maintained at <68°F. At the end of a traverse, the probe was withdrawn from the stack and the entire sampling train was transferred intact to the next sampling port. The remaining traverses of the stack were completed and the sampling train was withdrawn for the final leak check. This leak check was performed at 15-inches Mercury or at the highest vacuum achieved during the test. The S-type pitot tube was also checked at this time. The sample box and impinger train were sealed with aluminum foil and lowered to the mobile lab for sample recovery.

3.8 SAMPLE RECOVERY PROCEDURES FOR NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

Sample recovery occurred in the mobile lab. Each impinger was removed from the icebath, wiped dry and weighed to the nearest 0.1 gm. The contents of impingers 1 and 2 and bubbler 3 were transferred to a polyethylene sample bottle. The glass connectors, impingers 1 and 2 and bubbler 3 were rinsed with distilled water into this same bottle. All sample bottles and petri dishes were marked and labeled. A chain-of-custody log was completed and the field data sheet was also labeled with the sample ID numbers. The sampling train was then recharged in preparation for the next test.

3.9 SAMPLING PROCEDURES FOR ROC

The EPA Method 18 sampling train for ROC consists of a probe (4-foot stainless steel), a 4-foot Teflon sample line, a 10-liter Tedlar bag, a leak tight bag container and a vacuum pump with a rotameter. The entire train was purged with stack gas before collecting a sample. An integrated grab sample of the stack gases was collected over the test period. After sample collection, the Tedlar bag was lowered to the mobile lab for subsequent analysis. Triplicate grab samples were collected during the test series.

SECTION 4

ANALYTICAL PROCEDURES

This section describes the analytical procedures used for the sampled collected on this test program. All analysis were performed in the Steiner Environmental climate-controlled laboratory in Bakersfield, with the exception of fuel sample, which was analyzed by Pacific Gas Technology of Bakersfield, California.

4.1 ANALYSIS OF PM_{10}/SO_X SAMPLES

4.1.1 Nozzle, Probe, Filter Holder Wash

The volume of the acetone wash was measured and the wash was transferred to clean, tared, aluminum weighing dishes. The dishes were placed on temperature-controlled water bath under a fume hood and gently heated to dryness (100°F). The dishes with the dry residue were desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to the nearest 0.01 mg with a tolerance of <0.1 mg between weights). The ACS reagent grade acetone blank was treated in the same manner.

4.1.2 Filter

The 100-mm filter was removed from its petri dish and transferred to an oven where it was heated for 2 hours at 105°C. The filter was then desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to nearest 0.01 mg with a tolerance of <0.1 mg between weights). An unused, tared blank filter was treated in the same manner.

4.1.3 Filterable Particulate Sulfate

The acetone wash residue and the 100-mm filter were combined and then leached with distilled water to remove sulfate and the leachate was diluted to 100-ml. An aliquot was passed through ion exchange resin and titrated against 0.01N $BaCl_2$ (which was previously standardized against 0.0100N H_2SO_4) using the barium-thorin titration procedure specified in EPA Method 8. The acetone blank and 100-mm filter blank were treated in an identical manner.

4.1.4 Condensible Particulate, Sulfate, and SO_3

The 47-mm glass fiber filter was leached with distilled water and the leachate was added to the contents and rinse from impinger 1. The volume was measured and the entire volume was transferred to a clean, tared glass evaporating dish. The dish was placed on a temperature-controlled hot plate under a fume hood and gently heated to dryness (150°F). The dish with the dry residue was desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to nearest 0.01 mg with a tolerance of <0.1 mg between weights). The dry residue was dissolved in distilled water, diluted to 100-ml and analyzed for sulfate using the barium-thorin titration procedure. Approximately 5.0 ml of

0.1N HCl was added to the aliquot prior to titration with the $BaCl_2$ to prevent NH_3 interference. Three percent H_2O_2 was then added to the aliquot and the sample was titrated again to determine how much SO_2 has been removed due to reaction with NH_3 in the IPA. A blank 47-mm filter and 80% IPA solution were treated in the same manner.

4.1.5 SO_2

The volume of the contents and rinse from bubbler 2 and impinger 3 were measured and an aliquot was analyzed for sulfate using the barium-thorin procedure. A 3% H_2O_2 blank was treated in the same manner.

4.2 ANALYSIS OF NH_3 SAMPLES

The volume of the contents and rinse from impingers 1 and 2 and bubbler 3 were measured. A 25-ml aliquot of the impinger liquid was taken from the sample bottle. The NH_3 content was determined directly using a calibrated (two points) specific ion electrode. The 25-ml aliquot was placed in a 100-ml beaker with a Teflon stir bar. NH_3 ionic strength adjuster (ISA) solution was added until a blue color persisted. The electrode was rinsed with distilled water, immersed in the liquid, and allowed to reach a stable reading. A blank of the 0.1N HCl impinger solution was treated in an identical manner.

4.3 ANALYSIS OF HYDROCARBON SAMPLES

The grab sample of hydrocarbons were analyzed using a SRI Instruments Model 9300B gas chromatograph with a flame ionization detector. After purging the sample loop three times, a 1-ml sample was extracted from the Tedlar sample bag and injected onto a 6-foot long, 1/8-inch stainless steel column containing silica gel at 75°F for 2 minutes. The column temperature was ramped to 225°F. The C_1 hydrocarbon was separated and the $>C_1$

hydrocarbons were eluted to the detector for quantifcation. A Mitac 486 Notebook computer was used to record and integrate the signal from the GC. A ±1% certified calibration gas (C_1-C_6 in N_2) was used to calibrate the GC before and after sample analysis to quantify the C_1 and >C_1 hydrocarbons. The beginning and end calibrations must agree within ±5% for the data to be acceptable. Duplicate analysis of selected samples were performed to insure replication within ±5%.

4.3 FUEL

A sample of the natural gas fired during this test program was collected and sent to Pacific Gas Technology for analysis. Analysis was performed by PGT in accordance with EPA Title 40 Section 60.45. The specific procedures are itemized in Table 4-1.

TABLE 4-1. FUEL ANALYSIS METHODS

Laboratory Test Procedures for Fuel Gases

Reference: EPA Title 40, Section 60.45

GASEOUS FUELS BY GAS-LIQUID CHROMATOGRAPHY:

Gas Analysis	ASTM D1945-81
Sulfur Analysis	CPA B16
Calculation of Gross Calorific Value	ASTM D3588-81
Component Wt-%, F-factor calculations	EPA 40:60.45

PGT
Pacific Gas Technology

2122 Q Street
Bakersfield, CA 93301
Telephone: 805 324-1317
Fax: 805 324-2746

Attention: Mr. Jim Steiner
Steiner Environmental, Inc
4930 Boylan Street
Bakersfield, CA 93308

Sampled: March 11, 1998
Submitted: March 19, 1998
Analyzed: March 20, 1998
Reported: March 23, 1998

Gas Analysis by Chromotography - ASTM D 3588-91

Company: Stewart & Stevensen
Location: GTA
Description:

Lab No.: 98027801
Steiner No.: 50134
Sample Type: Natural Gas

Component	Mole %	Weight %	G/MCF
Oxygen	ND	0.00	
Nitrogen	0.68	1.12	
Carbon Dioxide	0.86	2.22	
Hydrogen	ND	0.00	
Carbon Monoxide	ND	0.00	
Hydrogen Sulfide	ND	0.00	
Methane	94.01	88.35	
Ethane	3.87	6.82	
Propane	0.58	1.50	0.160
iso-Butane	ND	0.00	0.000
n-Butane	ND	0.00	0.000
iso-Pentane	ND	0.00	0.000
n-Pentane	ND	0.00	0.000
Hexanes Plus	ND	0.00	0.000
Totals	100.00	100.00	0.160

			Values Corrected for Compressibility
Specific Volume, ft3/lb		22.23	
Compressibility (Z) Factor		0.9978	
Specifc Gravity, Calculated		0.5894	0.5904
GROSS			
BTU/ft3	Dry	1032.6	1034.9
	Wet	1014.5	1016.7
BTU/lb	Dry	22954.7	23005.2
BTU/lb	Wet	22553.0	22602.6
NET			
BTU/ft3	Dry	931.0	933.0
	Wet	914.7	916.7
BTU/lb	Dry	20696.4	20742.0
BTU/lb	Wet	20334.2	20379.0

CHONS	Weight %
Carbon	73.423
Hydrogen	23.849
Oxygen	1.612
Nitrogen	1.116
Sulfur	0.000

F FACTOR @
68 deg F, dscf/MMBTU

F FACTOR @
60 deg F, dscf/MMBTU

Hydrogen Sulfide, ppm	Not Tested	*Method*	**GC/FPD**
Dew Point, deg F	Not Tested	*Method*	**Bureau of Mines**
Moisture, lbs H2O/MMCF	Not Tested	*Method*	**Bureau of Mines**

ND: None Detected *Tr Trace*

SECTION 5

QUALITY ASSURANCE

5.1 MANUAL SAMPLING EQUIPMENT

A detailed record of repair and maintenance to each sampling train is kept. Preventative maintenance to each system is performed periodically to avoid complete component breakdown during a field test.

A detailed record of sampling system calibrations is also kept. Calibration data for the sampling nozzles, pitot tubes, dry gas meters and orifice meters are available for review. The calibration data for the equipment used on this program may be found in the Appendix of the final report.

5.2 LAB ANALYSIS

All field samples are assigned a label and an ID number. This ID is also affixed to a chain-of-custody log and to the field data sheet to eliminate any chance of sample mixup.

Prior to analysis, all glassware is thoroughly cleaned (soap and water, tap water rinse, distilled water rinse, IPA rinse) to eliminate any contamination. The evaporating dishes used to evaporate the samples are treated the same as a sample (dried in an oven, desiccated and weighed repeatedly at 6-hour intervals until a constant weight is achieved).

The glassware used to measure volumes and make transfers and dilutions are all NIST Class A to insure accurate measurements. All weights are carried out on a Sartorius Research Model R160P electronic semi-micro balance supported by a marble table in a separate room from the main analytical laboratory. The balance is calibrated regularly against an NIST Class S-1 weight.

All reagents used in the field and in the laboratory are ACS reagent grade and blanks of these reagents are evaluated for every set of tests. Blanks are taken in the field from the squeeze bottles and not the original container. Records are kept on these blanks to insure consistent quality of the reagents. Prior to use, the IPA is also analyzed to insure no peroxides are present which could lead to high SO_3 and low SO_2 values.

A quality control program consisting of duplicate analysis (to measure precision), spikes (to measure recovery efficiency) or analysis of blind standards (to measure accuracy) is implemented for each test program. Table 5-1 summarizes the results of the QA/QC checks.

5.3 QUALITY ASSURANCE/QUALITY CONTROL FOR CONTINUOUS MONITORS

The results of the checks performed on the Steiner Environmental CEMS during the test program are presented in the Appendix of the final report. The interference tests performed on the NO_X, CO, CO_2 and O_2 analyzers using EPA Method 20 will also be included.

5.4 QUALITY ASSURANCE OF ROC ANALYSIS

Each sample container is purged in the field with sample prior to the actual tests. A certified gas is used to calibrate the gas chromatograph used to measure the hydrocarbons.

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EMISSION TESTS AT
STEWART & STEVENSON OPERATIONS, INC.
COGENERATION FACILITY
SACRAMENTO, CA

HRSG-B
March 12 and 13, 1998

Prepared for:

Stewart & Stevenson Operations, Inc.
5000 83rd Street
Sacramento, California 95826
(916) 381-2921

April 1998

Prepared by:

Steiner Environmental, Inc.
4930 Boylan Street
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(805) 334-1102

PS-98-3978/Project 7872-98

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SECTION 1

INTRODUCTION

At the request of Stewart & Stevenson Operations, Inc., Steiner Environmental, Inc. conducted emission tests on the HRSG stack of gas turbine B at the cogeneration plant located next to the Proctor & Gamble Plant in Sacramento. The purpose of these tests was to determine the relative accuracy of the CERMS and to determine compliance with the limitations contained in the ATC (Final Determination of Compliance) issued by the Sacramento Metropolitan AQMD. These tests were conducted on March 12 and 13 , 1998.

The Sacramento Cogeneration Authority (SCA), which is comprised of the Sacramento Municipal Utility District (SMUD) and the Sacramento Municipal Utility District Financing Authority, has built a 171-MW peak load cogeneration plant adjacent to the Proctor & Gamble manufacturing plant in Sacramento, California. The cogeneration plant consists of two natural gas fired, combined cycle gas turbines and a single natural gas fired auxiliary boiler.

The gas turbines are General Electric LM6000 units, each rated at 421.4 MMBtu/hr. Each turbine drives a 42 MW electric generator. The inlet air to each turbine is cooled with chilled water provided to cooling coils in the inlet filter housing during the hot summer months. Water injection into each turbine is used for partial NO_x control.

The hot turbine exhaust gases (~1,036,000 lb/hr at 844°F) enter a heat recovery steam generator (HRSG) equipped with a duct burner rated at 75.39 MMBtu/hr. Both HRSG's are capable of providing enough steam to drive a steam turbine and produce an additional 28 MW without the duct burner in operation. With the duct burners in operation, an additional 43.3 MW of power may be generated. The HRSG is equipped with an oxidation catalyst to reduce CO (90%) and ROC (10%) emissions. The HRSG also contains a selective catalytic reduction (SCR) unit for additional NO_x control. Approximately 10 gal/hr of aqueous ammonia is injected onto the catalyst to reduce NO_x to less than 5 ppm at 15-percent O_2.

The exhaust gases from the HRSG's are discharged into separate stacks and then into the atmosphere. Each stack is equipped with a single point, dry, extractive CERMS to continuously monitor NO_x, CO and O_2 emissions.

For compliance demonstration, four tests were conducted for PM_{10}, SO_x, NO_X, CO, NH_3, and hydrocarbon to determine compliance. Four 120-minute tests were done using EPA Method 5/8 to measure PM_{10} (assume all PM is PM_{10}) at 100-percent load with the duct burners on. At the same time, four 120-minute tests were conducted to measure NO_X, CO_2, O_2 and CO using EPA Methods 7E, 3A and 10.

Four 120-minute NH_3 slip tests were conducted using BAAQMD Method ST-1B. Four 120-minute EPA Method 18 tests were also be done to measure ROC.

At 50-percent load, with no duct burners in operation, triplicate tests for NO_x, CO and ROC were performed. Triplicate 60-minute tests for NO_x, CO_2, O_2 and CO were done using EPA Methods 7E, 3A and 10. Triplicate 60-minute tests were done for flowrate and H_2O using EPA Methods 2/4 and for ROC using EPA Method 18.

During the PM_{10} tests at 100-percent load, a single 7-hour EPA Method 5/8 test was performed on the inlet air entering the turbine to measure PM_{10} (assumes all PM is PM_{10}) and SO_x.

For the relative accuracy tests, nine 32-minute tests for NO_x, CO_2, O_2 and CO were conducted using EPA Methods 7E, 3A and 10. Nine 32-minute flowrate and H_2O tests were conducted using EPA Methods 2/4.

A sample of the natural gas fired in the turbine and duct burners was collected and analyzed for CHNOS, moisture, specific gravity and Btu using ASTM Methods.

Section 2 presents the test matrix for this program.

SECTION 2

TEST MATRIX

Table 2-1 summarizes the tests performed on HRSG-A on this program. Tables 2-2 to 2-7 present the results of the compliance tests at 50-percent and 100-percent load. Table 2-8 compares the measured emissions with those allowed by the permit. All data are reported at 68°F and 29.92 inches Hg. Tables 2-9 through 2-15 present the relative accuracy test results.

2.1 COMPLIANCE TESTS

Gas turbine B was in compliance with the NO_x, CO and ROC limits at both 50-percent (no duct burners) and 100-percent loads (with duct burners). The turbine was also in compliance with the PM_{10} emission limit at 100 percent load with the duct burners on. The turbine was not in compliance with the SO_x (sulfate plus SO_2) limits in the permit. The measured NH3 slip was also below the permitted limit of 10 ppm at 15-percent O_2.

The ambient SO_x (sulfate plus SO_2) at the inlet of the turbine was <5 percent of the SO_x measured at the HRSG stack and therefore, was not a contributing factor to the SO_x exceeding the limit. The sulfur content of the natural gas is responsible for the SO_x. Detailed fuel sulfur tests were performed at SPA/Campbell Soup cogen and it was clear that the SO_x emission limits were set too low for the sulfur content of the natural gas being consumed by that cogen. The same problem has probably occurred here. Compliance test 3 at 100-percent load, with duct burners, was terminated halfway through the test because the duct burners went down. Otherwise, operating conditions during the remaining compliance tests were stable.

2.2 RELATIVE ACCURACY TESTS

EPA Performance Specifications 2, 3 4 and 6 limit the relative accuracy of NO_x, O_2, CO and flowrate monitors (or flowrate calculations) to ± 20%, ±10% and ±20%. The NO_x analyzer met this criterion on a ppm, ppm @ 15% O_2 and lb/hr basis. The O_2 analyzer met the criteria. The CO analyzer failed the criteria because the CO levels were barely above the detection limit of the analyzer (0.1 ppm). Performance Specification 4 allows low CO emitters to meet a ±5 ppm limit which this CO analyzer met. The flowrate calculation met the ±20% limit.

Section 3 describes the equipment and procedures to be used to conduct these tests.

TABLE 2-1. HRSG-B TEST MATRIX

Date	Test No.	Test Parameter	Test Time	Test Condition
3/12/98	1	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	0744 - 0900	323.7 MMBtu/hr 30.58 MW
	2	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	0918 - 1032	
	3	NO_x, CO_2, O_2, CO, ROC Flowrate/H_2O	1049 - 1159	
	1	NO_x, CO_2, O_2, CO, ROC, PM_{10}, Sulfate, SO_2, Flowrate/H_2O	1322 - 1647	455.6 MMBtu/hr 43.6 MW
	2	NO_x, CO_2, O_2, CO, ROC, PM_{10}, Sulfate, SO_2, Flowrate/H_2O	1719 - 1936	
	3[a]	NO_x, CO_2, O_2, CO, ROC, PM_{10}, Sulfate, SO_2, Flowrate/H_2O	2010 - 2118	
3/13/98	4	NO_x, CO_2, O_2, CO, ROC, PM_{10}, Sulfate, SO_2, Flowrate/H_2O	0810 - 1026	457.59 MMBtu/hr 43.93 MW
	1	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1105 - 1145	460.43 MMBtu/hr 43.93 MW
	2	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1200 - 1239	
	3	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1252 - 1332	

[a]Test aborted half way through; duct burners down

TABLE 2-1. HRSG-A TEST MATRIX (Concluded)

Date	Test No.	Test Parameter	Test Time	Test Condition
3/13/98	4	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1350 - 1430	460.43 MMBtu/hr 43.93 MW
	5	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1444 - 1525	
	6	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1537 - 1618	
	7	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1637 - 1717	
	8	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1730 - 1810	
	9	NO_x, CO_2, O_2, CO, Flowrate/H_2O	1823 - 1905	

TABLE 2-2

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 12,1998

	1	2	3	Average
Test Number	1	2	3	Average
Test Condition		50% LOAD		
Barometric Pressure (in. Hg)	29.80	29.80	29.80	29.80
Stack Pressure (in. Hg)	29.77	29.77	29.77	29.77
Stack Area (ft2)	77.07	77.07	77.07	77.07
Elapsed Sampling Time (min.)	60.0	60.0	60.0	60.0
Volume Gas Sampled (dscf)	51.167	50.945	50.809	50.974
F-Factor	8633.30	8633.30	8633.30	8633.30
GAS DATA				
Average Gas Velocity (fps)	60.49	61.33	60.56	60.79
Average Gas Temperature (dF)	231.50	230.75	230.17	230.81
Gas Flowrate (dscfm)	194033	198419	196501	196318
Gas Analysis (Volume %)				
Carbon Dioxide, dry	3.16	3.17	3.16	3.16
Oxygen, dry	15.54	15.35	15.35	15.41
Water	8.71	8.03	7.82	8.19
EMISSION CONCENTRATION				
CO (ppm)	0.95	0.98	1.02	0.98
NOx (ppm)	3.57	3.58	3.56	3.57
>C1 HC (ppm)	0.00	0.00	0.00	0.00
EMISSION RATE - lb/hr				
CO	0.80	0.85	0.87	0.84
NOx	4.96	5.09	5.01	5.02
>C1 HC	0.00	0.00	0.00	0.00
EMISSION FACTOR - lb/MMBtu				
CO	0.0023	0.0023	0.0024	0.0024
NOx	0.0144	0.0139	0.0138	0.0140
>C1 HC	0.0000	0.0000	0.0000	0.0000
EMISSION CONCENTRATION - @ 15% O2				
CO	1.05	1.04	1.08	1.06
NOx	3.93	3.81	3.78	3.84
>C1 HC	0.00	0.00	0.00	0.00

TABLE 2-3

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 12,1998

Test Number	1	2	3
Test Condition		100% LOAD	
Barometric Pressure (in. Hg)	29.80	29.75	29.75
Stack Pressure (in. Hg)	29.76	29.71	29.71
Stack Area (ft2)	77.07	77.07	77.07
Elapsed Sampling Time (min.)	120.0	120.0	60.0
Volume Gas Sampled (dscf)	109.695	109.776	51.682
F-Factor	8633.30	8633.30	8633.30
GAS DATA			
Average Gas Velocity (fps)	68.47	69.14	65.29
Average Gas Temperature (dF)	227.06	227.25	228.13
Gas Flowrate (dscfm)	219801	223010	208164
Gas Analysis (Volume %)			
Carbon Dioxide, dry	4.06	4.07	4.09
Oxygen, dry	13.75	13.74	13.73
Water	9.18	8.57	9.51
EMISSION CONCENTRATION			
Filterable Particulate (gr/dscf)	0.0004	0.0009	0.0018
Total Particulate (gr/dscf)	0.0011	0.0010	0.0022
Total Sulfate (gr/dscf)	0.0003	0.0004	0.0006
CO (ppm)	0.75	0.72	0.69
SO2 (ppm)	0.01	0.01	0.03
NOx (ppm)	5.05	5.04	5.08
>C1 HC (ppm)	0.00	0.00	0.00
EMISSION RATE - lb/hr			
Filterable Particulate	0.77	1.65	3.20
Total Particulate	2.11	1.85	3.97
Total Sulfate	0.62	0.68	1.08
CO	0.72	0.70	0.63
SO2	0.03	0.03	0.06
NOx	7.95	8.05	7.58
>C1 HC	0.00	0.00	0.00
EMISSION FACTOR - lb/MMBtu			
Filterable Particulate	0.0015	0.0031	0.0064
Total Particulate	0.0040	0.0035	0.0080
Total Sulfate	0.0012	0.0013	0.0022
CO	0.0014	0.0013	0.0013
SO2	0.0001	0.0001	0.0001
NOx	0.0152	0.0152	0.0153
>C1 HC	0.0000	0.0000	0.0000
EMISSION CONCENTRATION - @ 15% O2			
CO	0.62	0.59	0.57
SO2	0.01	0.01	0.02
NOx	4.17	4.15	4.18
>C1 HC	0.00	0.00	0.00

TABLE 2-4

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 13,1998

Test Number	4
Test Condition	100% LOAD
Barometric Pressure (in. Hg)	29.80
Stack Pressure (in. Hg)	29.75
Stack Area (ft2)	77.07
Elapsed Sampling Time (min.)	120.0
Volume Gas Sampled (dscf)	110.061
F-Factor	8633.30
GAS DATA	
Average Gas Velocity (fps)	69.21
Average Gas Temperature (dF)	225.44
Gas Flowrate (dscfm)	223109
Gas Analysis (Volume %)	
Carbon Dioxide, dry	4.12
Oxygen, dry	13.83
Water	9.00
EMISSION CONCENTRATION	
Filterable Particulate (gr/dscf)	0.0005
Total Particulate (gr/dscf)	0.0007
Total Sulfate (gr/dscf)	0.0003
CO (ppm)	0.71
SO2 (ppm)	0.01
NOx (ppm)	4.88
>C1 HC (ppm)	0.00
EMISSION RATE - lb/hr	
Filterable Particulate	0.96
Total Particulate	1.38
Total Sulfate	0.55
CO	0.69
SO2	0.03
NOx	7.80
>C1 HC	0.00
EMISSION FACTOR - lb/MMBtu	
Filterable Particulate	0.0018
Total Particulate	0.0026
Total Sulfate	0.0011
CO	0.0013
SO2	0.0001
NOx	0.0149
>C1 HC	0.0000
EMISSION CONCENTRATION - @ 15% O2	
CO	0.59
SO2	0.01
NOx	4.07
>C1 HC	0.00

TABLE 2-5

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 12,1998

Test Number	1-NH3	2-NH3	3-NH3
Test Condition		100% LOAD	
Barometric Pressure (in. Hg)	29.80	29.75	29.75
Stack Pressure (in. Hg)	29.76	29.71	29.71
Stack Area (ft2)	77.07	77.07	77.07
Elapsed Sampling Time (min.)	120.0	120.0	120.0
Volume Gas Sampled (dscf)	112.668	112.843	56.434
F-Factor	8633.30	8633.30	8633.30
GAS DATA			
Average Gas Velocity (fps)	73.52	73.84	79.08
Average Gas Temperature (dF)	223.50	222.25	220.88
Gas Flowrate (dscfm)	235574	236986	254408
Gas Analysis (Volume %)			
Carbon Dioxide, dry	4.06	4.07	4.09
Oxygen, dry	13.75	13.74	13.73
Water	9.82	9.68	9.66
EMISSION CONCENTRATION			
NH3 (ppm)	3.40	3.36	3.13
EMISSION RATE - lb/hr			
NH3	2.13	2.12	2.12
EMISSION FACTOR - lb/MMBtu			
NH3	0.0038	0.0038	0.0035
EMISSION CONCENTRATION - @ 15% O2			
NH3	2.81	2.77	2.58

TABLE 2-6

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 13,1998

Test Number	4-NH3
Test Condition	100% LOAD
Barometric Pressure (in. Hg)	29.80
Stack Pressure (in. Hg)	29.75
Stack Area (ft2)	77.07
Elapsed Sampling Time (min.)	120.0
Volume Gas Sampled (dscf)	114.290
F-Factor	8633.30
GAS DATA	
Average Gas Velocity (fps)	73.75
Average Gas Temperature (dF)	220.81
Gas Flowrate (dscfm)	237247
Gas Analysis (Volume %)	
Carbon Dioxide, dry	4.12
Oxygen, dry	13.83
Water	9.81
EMISSION CONCENTRATION	
NH3 (ppm)	3.78
EMISSION RATE - lb/hr	
NH3	2.39
EMISSION FACTOR - lb/MMBtu	
NH3	0.0043
EMISSION CONCENTRATION - @ 15% O2	
NH3	3.15

TABLE 2-7

SUMMARY OF SOURCE EMISSION TEST DATA (68 dF)

Unit Tested : STEWART/STEVENSON HRSG - B   Date : MAR 12,1998

Test Number	1
Test Condition	AMBIENT
Barometric Pressure (in. Hg)	29.80
Stack Pressure (in. Hg)	
Stack Area (ft2)	
Elapsed Sampling Time (min.)	420.0
Volume Gas Sampled (dscf)	789.362
GAS DATA	
Average Gas Velocity (fps)	
Average Gas Temperature (dF)	
Gas Flowrate (dscfm)	
Gas Analysis (Volume %)	
Carbon Dioxide, dry	0.00
Oxygen, dry	20.90
Water	0.00
EMISSION CONCENTRATION	
Filterable Particulate (gr/dscf)	1.14E-04
Total Particulate (gr/dscf)	1.47E-04
Total Sulfate (gr/dscf)	8.80E-06
SO2 (ppm)	1.54E-03

TABLE 2-8. MEASURED VERSUS ALLOWABLE EMISSIONS

Emission	Measured		Allowable	
	50%	100%	50%[a]	100%[b]
NO_x ppm @ ~~3~~ 15 % O2	3.84	4.14	5.0	5.0
NO_x lb/hr	5.02	7.85	7.7	9.2
CO lb/hr	0.84	0.69	3.6	4.2
ROC lb/hr	0.00	0.00	1.1	1.8
SO_x lb/hr	--	0.77	--	0.32
PM_{10} lb/hr	--	2.33	--	3.3
NH_3 ppm @ 15% O_2	--	4.14	--	10.0

[a]Combined cycle CTG limit
[b]CTG plus duct burner limit

TABLE 2-9

RELATIVE ACCURACY DETERMINATION - O2 (%)

COMPANY :STEWART/STEVENSON DATE : MAR 13,1998

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	14.66	15.05	-0.39
2	14.16	15.04	-0.88
3	14.55	14.99	-0.44
4	14.54	14.99	-0.45
5	14.50	14.97	-0.47
6	14.62	14.98	-0.36
7	14.68	14.99	-0.31
8	14.68	15.02	-0.34
9	14.65	15.03	-0.38

* a - Values not used in calculations. b - Values used.

Mean : 14.56

Mean : -0.45
Standard Deviation : 0.17

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.13

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$RA (\%) = [|\bar{d}| + |CC| / \overline{RM}] \times 100$ = 3.98

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-10
RELATIVE ACCURACY DETERMINATION - NOx (ppm)

COMPANY :STEWART/STEVENSON DATE : MAR 13,1998

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	4.26	4.38	-0.12
2	4.17	4.36	-0.19
3	4.34	4.64	-0.30
4	4.18	4.38	-0.20
5	4.37	4.61	-0.24
6	4.32	4.63	-0.31
7	4.29	4.41	-0.12
8	4.27	4.52	-0.25
9	4.23	4.45	-0.22

* a - Values not used in calculations. b - Values used.

Mean : 4.27 Mean : 4.49 Mean : -0.22
Standard Deviation : 0.07

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.05

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$RA (\%) = [|\bar{d}| + |CC| / \overline{RM}] \times 100$ = 6.32

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-11

RELATIVE ACCURACY DETERMINATION - NOx (ppm @ 15% O2)

COMPANY :STEWART/STEVENSON DATE : MAR 13,1998

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	4.03	4.41	-0.38
2	3.65	4.38	-0.73
3	4.03	4.63	-0.60
4	3.88	4.38	-0.50
5	4.03	4.59	-0.56
6	4.06	4.62	-0.56
7	4.07	4.40	-0.33
8	4.05	4.54	-0.49
9	3.99	4.48	-0.49

* a - Values not used in calculations. b - Values used.

Mean : 3.98 Mean : 4.49 Mean : -0.52
Standard Deviation : 0.12

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.09

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$RA (\%) = [|\bar{d}| + |CC| / \overline{RM}] \times 100$ = 15.34

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-12

RELATIVE ACCURACY DETERMINATION - NOx (lb/hr)

COMPANY :STEWART/STEVENSON   DATE : 3/13/98

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	7.37	7.45	-0.08
2	7.10	7.41	-0.31
3	7.49	7.84	-0.35
4	7.18	7.42	-0.24
5	7.57	7.77	-0.20
6	7.38	7.87	-0.49
7	7.40	7.44	-0.04
8	7.37	7.70	-0.33
9	7.28	7.61	-0.33

* a - Values not used in calculations. b - Values used.

Mean : 7.35   Mean : 7.61   Mean : -0.26

Standard Deviation : 0.14

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.11

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 5.03

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-13

RELATIVE ACCURACY DETERMINATION - CO (ppm)

COMPANY :STEWART/STEVENSON DATE : MAR 13,1998

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	0.55	0.02	0.53
2	0.57	0.02	0.55
3	0.61	0.02	0.59
4	0.66	0.02	0.64
5	0.69	0.02	0.67
6	0.69	0.02	0.67
7	0.69	0.02	0.67
8	0.67	0.02	0.65
9	0.67	0.03	0.64

* a - Values not used in calculations. b - Values used.

Mean : 0.64

Mean : 0.62
Standard Deviation : 0.05

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.04

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$$RA (\%) = [|\bar{d}| + |CC| / \overline{RM}] \times 100 = 102.41$$

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-14

RELATIVE ACCURACY DETERMINATION - CO (lb/hr)

COMPANY :STEWART/STEVENSON DATE : 3/13/98

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	0.58	0.02	0.56
2	0.59	0.02	0.57
3	0.54	0.02	0.52
4	0.69	0.02	0.67
5	0.73	0.02	0.71
6	0.72	0.02	0.70
7	0.72	0.02	0.70
8	0.70	0.02	0.68
9	0.70	0.03	0.67

* a - Values not used in calculations. b - Values used.

Mean : 0.66

Mean : 0.64
Standard Deviation : 0.07

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 0.05

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

$RA (\%) = [|\overline{d}| + |CC| / \overline{RM}] \times 100$ = 104.02

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

TABLE 2-15

RELATIVE ACCURACY DETERMINATION - FLOWRATE (dscfh)

COMPANY :STEWART/STEVENSON DATE : 3/13/98

SOURCE :HRSG - B

Test No.	RM value or Corrected Gas Value (Cgas) * a ------- b	Test Monitor Value * a ------- b	Difference d
1	14497.44	14265.96	231.48
2	14248.68	14252.22	-3.54
3	14456.70	14174.68	282.02
4	14391.36	14169.22	222.14
5	14506.02	14154.27	351.75
6	14312.70	14202.37	110.33
7	14437.32	14204.95	232.37
8	14446.56	14275.17	171.39
9	14413.26	14319.70	93.56

* a - Values not used in calculations. b - Values used.

Mean : 14412. Mean : 14224. Mean : 187.94

Standard Deviation : 107.58

t-Values Table

n	t0.975	n	t0.975
2	12.706	10	2.262
3	4.303	11	2.228
4	3.182	12	2.201
5	2.776	13	2.179
6	2.571	14	2.160
7	2.447	15	2.145
8	2.365	16	2.131
9	2.306		

CONFIDENCE COEFFICIENT

CC = t0.975 x [Std.Dev. / (Sq.Rt. n)] = 82.70

Where : CC = 2.5 percent error Confidence Coefficient.
n , number of test runs = 9
t0.975, t-Value from table = 2.306

RELATIVE ACCURACY

RA (%) = [$|\bar{d}|$ + |CC| / $\overline{RM}$] x 100 = 1.88

Where : RM = Average RM value or Corrected Gas Conc., (Cgas).

SECTION 3

SAMPLING EQUIPMENT AND PROCEDURES

This section of the source test plan describes the equipment and procedures to be used to conduct the particulate and gaseous tests on this program.

3.1 PRELIMINARY MEASUREMENTS

Before conducting the stack tests a series of preliminary measurements are made to determine:

- The location of the sampling site and the number and location of the sampling points to be used (EPA Method 1)
- The velocity, temperature and pressure of the stack gases (EPA Method 2)
- The composition of the stack gases (EPA Method 3A)
- The moisture content of the stack gases (EPA Method 4)

Using the results of these preliminary measurements and the calibration constants for the sampling train, a series of calculations are made to determine the value of K, a constant, and N_d, ideal nozzle diameter, required to run an isokinetic test according to the equation:

$$\Delta H = \left[\frac{60^2\ \pi^2 (K_p)^2 (C_p)^2 (1-B_{wo})^2\ P_s\ MW_d}{576^2 (K_o)^2\ MW_s\ P_m}\right] (N_d)^4 \left(\frac{T_m}{T_s}\right) (\Delta P)$$

where

$$K = \left[\frac{60^2 \, \pi^2 (K_p)^2 (C_p)^2 \, (1 - B_{wo})^2 \, P_s \, MW_d}{576^2 (K_o)^2 \, MW_s \, P_m} \right]$$

An actual nozzle, whose diameter was as close as possible to the ideal nozzle diameter, was selected for the test. Isokinetic sampling rates for each sampling point in the stack are computed using the equation:

$$\Delta H = (K)(N_d)^4 \left(\frac{T_m}{T_s} \right) (\Delta P)$$

Since K and N_d were known, and remained constant during a test, the only variables were the meter temperatures, the stack gas temperature and the velocity pressure for each sampling point.

3.2 PREPARATION OF THE PM_{10}/SO_X SAMPLING TRAIN

All sampling train components were cleaned in the laboratory (soap and water, tap water rinse, distilled water rinse, and IPA rinse) to eliminate previous contamination. The sampling train components were sealed and transported to the sampling site in a mobile lab. The EPA Method 5/8 equipment used to measure PM_{10} (filterable and condensible particulate counted as PM_{10}) and SO_X consisted of:

- A calibrated 316 stainless steel nozzle for isokinetic sampling
- A heated Pyrex glass sampling probe (6 feet long) equipped with an S-type pitot tube and a thermocouple to measure stack velocity, pressure and temperature

- A heated Pyrex glass filter holder containing a weighed 100-mm Whatman 934 AH glass fiber filter
- A Pyrex glass impinger train in an icebath (impinger 1 containing 100-ml 80% IPA; a Pyrex glass filter holder containing a 47-mm Whatman 934 AH filter; bubbler 2 and impinger 3 each containing 100-ml of 3% H_2O_2; bubbler 4 contains a weighed amount of silica gel)
- An umbilical to connect the probe and sample box to the control module
- A control module containing a vacuum pump, a calibrated dry gas meter and a calibrated orifice meter to measure the pressure, temperature and flowrate throughout the train.

The sampling train was charged in the mobile lab using freshly prepared reagents. Each impinger and its contents was weighed to the nearest 0.1 gm on a calibrated electronic balance. Blanks of all filters and reagents were retained for subsequent analysis. The sampling point locations were marked on the probe using a high-temperature marker. The sampling train was completely assembled and lifted to the sampling site.

3.3 SAMPLING PROCEDURES FOR PM_{10}/SO_X SAMPLING TRAIN

Prior to a test, the sampling train was heated and leak checked at 15-inches Hg to insure leakage was less than 0.02 or 4 percent of the average sampling rate. The S-type pitot tube was also leak checked. The sampling train was installed on the unirail and the probe was inserted into the stack at the farthest point. An isokinetic sampling rate was calculated using an HP-41Cx calculator for each sampling point on the traverse (4 points per traverse, 4 traverses at 90°). Each point was sampled for an equal period of time (7.5

minutes) and all pertinent data were recorded on the data sheet every 7.5 minutes for each point. The probe and sample box were maintained at 250°F throughout the traverse. The gases leaving the impinger train were maintained at <68°F. At the end of a traverse, the probe was withdrawn from the stack and the entire sampling train was transferred intact to the next sampling port. After the final traverse of the stack was completed, the sampling train was withdrawn for the final leak check. This leak check was performed at 15-inches Hg or at the highest vacuum achieved during the test. The S-type pitot tube was also checked at this time. The sampling train was then purged with ambient air for 15-minutes using the highest ΔH measured during the test. After the train was purged, the sample box and impinger train were sealed with aluminum foil and lowered to the mobile lab for sample recovery.

3.4 SAMPLE RECOVERY PROCEDURES FOR PM_{10}/SO_X SAMPLING TRAIN

Sample recovery for the nozzle and probe occurred on the stack. The nozzle and probe were brushed and rinsed three times using ACS reagent grade acetone into a polyethylene sample bottle. Sample recovery for the filter holder and impinger train occurred in the mobile lab. The 100-mm filter was removed from the 4-inch filter holder and sealed in its petri dish. The glass fibers stuck to the gasket were scraped off and put into the petri dish. The probe-to-filter connector and the front half of the 4-inch glass filter holder were brushed and rinsed with acetone into the bottle containing the nozzle and probe wash. Each impinger was removed from the icebath, wiped dry and weighed to the nearest 0.1 gm. The contents of impinger 1 were transferred to a polyethylene sample bottle. The back half of the 4-inch glass filter holder, the glass connectors, impinger 1 and the front half of the 2-inch filter holder were rinsed with 80% IPA into this same bottle. The 47-mm filter from the 2-inch filter holder was sealed in its petri dish. The contents of bubbler 2 and impinger 3 were transferred to a polyethylene sample bottle. The back half of the 2-inch filter holder, bubbler 2, the connector and impinger 3 were rinsed with distilled water into this same bottle. All sample bottles and petri dishes were marked and labeled. A chain-of-custody log was completed and the field data sheet was also labeled with the sample ID numbers. The sampling train was then recharged in preparation for the next test.

3.5 SAMPLING PROCEDURES FOR CONTINUOUS MONITORING

The continuous monitors used in the Steiner Environmental Mobile Monitoring Lab are shown in Table 3-1. Figure 3-1 is a schematic of the continuous monitoring system. The procedures used to continuously monitor stack gases for NO_X, CO_2, O_2 and CO strictly follow EPA Methods 7E, 3A and 10.

Prior to the test program, the CEMS was assembled and leak checked. The sample probe was sealed with a cap and the flow through the individual rotameters was observed. The leak check was successful if the pressure at the analyzer system and the flow through the rotameters all drop to zero. A leak check of the entire CEMS was performed before and after each test to insure no leaks occur during movement of the sample probe from port to port. High range calibration gases (EPA Protocol 1) for NO_X, CO, CO_2 and O_2 were then introduced into each analyzer to calibrate the analyzer and recorder. Once these adjustments were completed, the analyzer calibration error checks were performed. Zero, mid-range and high-range calibration gases were introduced to the gas analyzers. No adjustments were made to the system except those necessary to achieve the proper

TABLE 3-1. CONTINUOUS MONITORING LAB

NO_x CHEMILUMINESCENT ANALYZER – THERMO ELECTRON MODEL 10

Response Time (0-90%)	1.5 sec – NO mode; 1.7 sec – NO_x mode
Zero Drift	Negligible after 1/2 hour warmup
Linearity	±1% of full scale
Accuracy	Derived from the NO or NO_2 calibration gas, ±1% of full scale
Output	0-10 V
Operating Ranges	0-2, 10, 25, 100, 250, 1000, 2500 and 10,000 ppm
Flowrate = 2 scfh	0-2.5

O_2 ANALYZER, FUEL TYPE – TELEDYNE MODEL 326

Response Time (0-90%)	60 seconds
Accuracy	±1% of scale at constant temperatures; ±1% of scale of ±5% of reading, which-ever is greater, over the operating temperature range
Output	0-1 V
Operating Ranges	0-5%, 10%, 25% O_2
Flowrate	2 scfh

CO/CO2 INFRARED - FUJI MODEL ZRH

Response Time (0-90%)	3 seconds
Zero Drift	2%
Span Drift	2%
Linearity	±1%
Resolution	<0.5% full scale
Output	0-1 V CO2; 4-20 mAmp CO
Operating Ranges	5% and 25% CO2; 0,5% and 2.5% CO
Flowrate	1 ±0.5 LPM

CO GAS FILTER CORRELATION – THERMO ELECTRON MODEL 48

Response Time (0-95%)	1 minute
Zero Drift	±0.2 ppm CO
Span Drift	Less than 1% full scale in 24 hours
Linearity	±1% full scale, all ranges
Accuracy	±0.1 ppm CO
Output	0-10 V
Operating Ranges	1, 2, 5, 10, 20, 50, 100, 200, 500, 1000 ppm
Flowrate	.5 - 2 LPM

SO_2 UV ANALYZER –WESTERN RESEARCH MODEL 721A/721AT

Response Time (0-90%)	Less than 60 seconds
Zero Drift	Less than 2% full scale in 24 hours
Linearity	±1% full scale
Accuracy	±2% full scale
Output	0-1 V
Operating Ranges	0-400 ppm/1-1000 ppm for Model 721; 0-100/0-1000 Model 721AT
Flowrate	1 LPM

STRIP CHART RECORDERS (3) – LINSEIS 7025

Pen Response	0.35 seconds Full Scale
Input Spans	1, 2, 5, 10, 20, 50, 100 MV
Zero Set	Stable access entire chart-width ±100%
Accuracy	.35% of Span
Dead Band	.15% of Span
Linearity	25% of Span
Chart Speed	1, 2, 5, 10, 20, 50, 100 cm/min; 1, 2, 5, 10, 20, 50 cm/hr; fast advance 100 cm/min; LED indicator; forward and reverse selector
Recording Pen	Fiber tip pen
Chart Width	250 mm

SCOTSMAN TRAILER

Fully Insulated, 8-ft x 12-ft with A/C and heat

1. Filter 0.6 μ, 99.9999 percent efficient
2. Duct
3. 316 stainless steel probe
4. 3/8-inch, heated (250°F) Teflon
5. Four-pass conditioner-dryer, 316 stainless steel internals
6. 3/8-inch, unheated Teflon
7. Teflon-lined sample pump
8. 3/8-inch unheated Teflon
9. Rotameter
10. 1/4-inch Teflon tubing
11. Calibration gas manifold
12. Calibration gas selector valve
13. Calibration gas cylinders
14. Backpressure regulator
15. Auxiliary analysis port

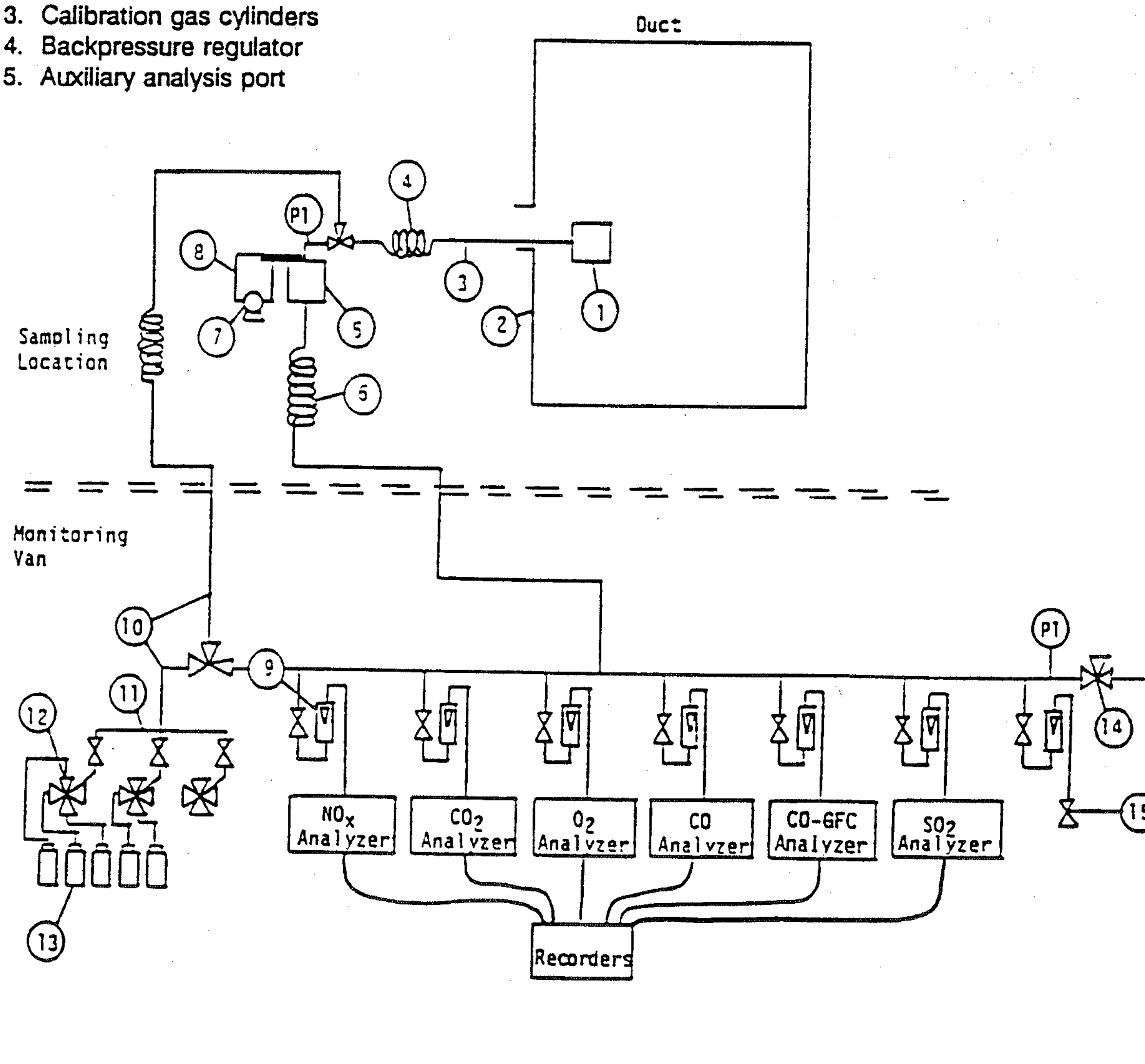

Figure 3-1. Schematic of Continuous Monitoring System.

calibration gas flowrate. The analyzer responses to each calibration gas were recorded on the CEMS field data sheet. If the difference between the gas concentration exhibited by each gas analyzer and the known concentration of each calibration gas, when each calibration gas was introduced directly to each analyzer, was less than ±2% of span for any calibration gas, the check was considered successful. Next, a sampling system bias check was performed by introducing calibration gases at the sample probe. A zero gas and either the mid-range or high-range calibration gas, whichever most closely approximates the stack gas concentrations, was used for this check. No adjustments were made to the system except those necessary to achieve the proper calibration gas flowrate. At the same time, the measurement system response time (95% of gas value) was determined for both the zero and upscale gases. The sampling system bias check was considered valid if the difference between the gas concentrations displayed by the measurement system for the analyzer calibration error check and the sampling system bias check were less than ±5% of span. The CEMS was now ready for the interference response test for NO_X, CO_2, O_2 and CO, which was performed in accordance with Section 5.4 of EPA Method 20. Each high-range calibration gas was introduced into the measurement system and the responses for the individual analyzers were recorded. If the response of each analyzer to the other interfering gases was less than ±2% of span, the system was considered to be interference free. Each reference method run was 32 minutes long.

A NO_X converter check was also performed. A certified gas (7.98 ppm NO_2 in N_2) was introduced into the NO_X analyzer with the analyzer set in the "NO_X" mode until a stable reading was obtained. The converter conversion efficiency was calculated by dividing the measured NO_2 concentration by the certified gas concentration. Testing can proceed if the converter efficiency was greater than 90%. The CEMS was now ready for use.

Sample was taken from the stack (at a single point for the 50- and 100-percent load RATA tests and 16 points for the 100-percent load with duct burners) using a 316 stainless steel probe. A heated Balston filter holder and fiberglass filter (99.9999 percent efficiency retention of 0.6 micron particles) were connected to the outlet of the probe. Sample gas was transported through heated Teflon sample line (maintained at >250°F) by a Teflon-lined diaphragm pump to a 316 stainless steel refrigeration type conditioner (Hankison Model E-4G-SS). The sample gas was passed through the conditioner two separate times under vacuum before entering the pump, then two additional times under pressure. The clean, dry sample gas (approximately 35°F) was then transported to the continuous analyzer system through an unheated Teflon line. A series of flowmeters, valves, and regulators maintain constant flow through the system at a constant pressure.

Calibrations of the continuous analyzers were performed using EPA Protocol 1 calibration gases (±1%) for NO_X, and CO, and NIST certified calibration gases (±1%) for CO_2 and O_2. All pertinent data (date, time, test locations, analyzer range, cal gas value) were recorded on both the data sheets and continuous analyzer strip charts in the field.

At the end of each run, the zero and upscale sampling system bias check was repeated. Zero drift and calibration drift determinations were made by calculating the difference in the measurement system output reading from the initial and final calibration response for both the zero and upscale gases. If the drift in either case was less than ±3%

of span, then the drift was considered acceptable. If the sampling system bias check was less than ±5% of span, the run was considered valid.

The measured gas concentrations were corrected for sampling system bias in accordance with Section 8 equation 6C-1 of EPA Method 6C.

3.6 PREPARATION OF THE NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

All sampling train components were cleaned in the laboratory (soap and water, tap water rinse, distilled water rinse, and IPA rinse) to eliminate previous contamination. The sampling train components were sealed and transported to the sampling site in a mobile lab. The BAAQMD Method ST-1B equipment used to measure NH_3, flowrate and moisture consisted of:

- A straight 316 stainless steel nozzle for constant rate sampling
- A heated Pyrex glass sampling probe (6 feet long) equipped with an S-type pitot tube and a thermocouple to measure stack velocity, pressure and temperature
- A heated sample box containing an untared 100-mm Whatman 934 AH glass fiber filter
- A Pyrex glass impinger train in an icebath (impingers 1 and 2 contained 100-ml 0.1N HCl; bubbler 3 was dry; bubbler 4 contained a weighed amount of silica gel)
- An umbilical to connect the probe and sample box to the control module

- A control module containing a vacuum pump, a calibrated dry gas meter and a calibrated orifice meter to measure the pressure, temperature and flowrate throughout the train.

The sampling train was charged in the mobile lab using freshly prepared reagents. Each impinger and its contents were weighed to the nearest 0.1 gm on a calibrated electronic balance. Blanks of all filters and reagents were retained for subsequent analysis. The sampling point locations were marked on the probe using a high-temperature marker. The sampling train was completely assembled and lifted to the sampling site.

3.7 SAMPLING PROCEDURES FOR NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

Prior to a test, the sampling train was heated and leak checked at 15-inches Hg to insure a leak rate of less than 0.02 cfm or 4 percent of the average sampling rate. The S-type pitot tube was also leak checked. The sampling train was installed on the unirail and the probe was inserted into the stack at the farthest point. A constant sampling rate was calculated using an HP-41CX calculator for each sampling point on the traverse (4 points per traverse; 4 traverses at 90°). Each point was sampled for an equal period of time (7.5 minutes) and all pertinent data were recorded on the data sheet every 7.5 minutes for each point. The probe and sample box were maintained at 250°F throughout the traverse. The gases leaving the impinger train were maintained at <68°F. At the end of a traverse, the probe was withdrawn from the stack and the entire sampling train was transferred intact to the next sampling port. The remaining traverses of the stack were completed and the sampling train was withdrawn for the final leak check. This leak check was performed at 15-inches Mercury or at the highest vacuum achieved during the test. The S-type pitot tube was also checked at this time. The sample box and impinger train were sealed with aluminum foil and lowered to the mobile lab for sample recovery.

3.8 SAMPLE RECOVERY PROCEDURES FOR NH_3/FLOWRATE/MOISTURE SAMPLING TRAIN

Sample recovery occurred in the mobile lab. Each impinger was removed from the icebath, wiped dry and weighed to the nearest 0.1 gm. The contents of impingers 1 and 2 and bubbler 3 were transferred to a polyethylene sample bottle. The glass connectors, impingers 1 and 2 and bubbler 3 were rinsed with distilled water into this same bottle. All sample bottles and petri dishes were marked and labeled. A chain-of-custody log was completed and the field data sheet was also labeled with the sample ID numbers. The sampling train was then recharged in preparation for the next test.

3.9 SAMPLING PROCEDURES FOR ROC

The EPA Method 18 sampling train for ROC consists of a probe (4-foot stainless steel), a 4-foot Teflon sample line, a 10-liter Tedlar bag, a leak tight bag container and a vacuum pump with a rotameter. The entire train was purged with stack gas before collecting a sample. An integrated grab sample of the stack gases was collected over the test period. After sample collection, the Tedlar bag was lowered to the mobile lab for subsequent analysis. Triplicate grab samples were collected during the test series.

SECTION 4

ANALYTICAL PROCEDURES

This section describes the analytical procedures used for the sampled collected on this test program. All analysis were performed in the Steiner Environmental climate-controlled laboratory in Bakersfield, with the exception of fuel sample, which was analyzed by Pacific Gas Technology of Bakersfield, California.

4.1 ANALYSIS OF PM_{10}/SO_X SAMPLES

4.1.1 Nozzle, Probe, Filter Holder Wash

The volume of the acetone wash was measured and the wash was transferred to clean, tared, aluminum weighing dishes. The dishes were placed on temperature-controlled water bath under a fume hood and gently heated to dryness (100°F). The dishes with the dry residue were desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to the nearest 0.01 mg with a tolerance of <0.1 mg between weights). The ACS reagent grade acetone blank was treated in the same manner.

4.1.2 Filter

The 100-mm filter was removed from its petri dish and transferred to an oven where it was heated for 2 hours at 105°C. The filter was then desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to nearest 0.01 mg with a tolerance of <0.1 mg between weights). An unused, tared blank filter was treated in the same manner.

4.1.3 Filterable Particulate Sulfate

The acetone wash residue and the 100-mm filter were combined and then leached with distilled water to remove sulfate and the leachate was diluted to 100-ml. An aliquot was passed through ion exchange resin and titrated against 0.01N $BaCl_2$ (which was previously standardized against 0.0100N H_2SO_4) using the barium-thorin titration procedure specified in EPA Method 8. The acetone blank and 100-mm filter blank were treated in an identical manner.

4.1.4 Condensible Particulate, Sulfate, and SO_3

The 47-mm glass fiber filter was leached with distilled water and the leachate was added to the contents and rinse from impinger 1. The volume was measured and the entire volume was transferred to a clean, tared glass evaporating dish. The dish was placed on a temperature-controlled hot plate under a fume hood and gently heated to dryness (150°F). The dish with the dry residue was desiccated and weighed repeatedly at 6-hour intervals until a constant weight was achieved (to nearest 0.01 mg with a tolerance of <0.1 mg between weights). The dry residue was dissolved in distilled water, diluted to 100-ml and analyzed for sulfate using the barium-thorin titration procedure. Approximately 5.0 ml of

0.1N HCl was added to the aliquot prior to titration with the $BaCl_2$ to prevent NH_3 interference. Three percent H_2O_2 was then added to the aliquot and the sample was titrated again to determine how much SO_2 has been removed due to reaction with NH_3 in the IPA. A blank 47-mm filter and 80% IPA solution were treated in the same manner.

4.1.5 $\underline{SO_2}$

The volume of the contents and rinse from bubbler 2 and impinger 3 were measured and an aliquot was analyzed for sulfate using the barium-thorin procedure. A 3% H_2O_2 blank was treated in the same manner.

4.2 ANALYSIS OF NH_3 SAMPLES

The volume of the contents and rinse from impingers 1 and 2 and bubbler 3 were measured. A 25-ml aliquot of the impinger liquid was taken from the sample bottle. The NH_3 content was determined directly using a calibrated (two points) specific ion electrode. The 25-ml aliquot was placed in a 100-ml beaker with a Teflon stir bar. NH_3 ionic strength adjuster (ISA) solution was added until a blue color persisted. The electrode was rinsed with distilled water, immersed in the liquid, and allowed to reach a stable reading. A blank of the 0.1N HCl impinger solution was treated in an identical manner.

4.3 ANALYSIS OF HYDROCARBON SAMPLES

The grab sample of hydrocarbons were analyzed using a SRI Instruments Model 9300B gas chromatograph with a flame ionization detector. After purging the sample loop three times, a 1-ml sample was extracted from the Tedlar sample bag and injected onto a 6-foot long, 1/8-inch stainless steel column containing silica gel at 75°F for 2 minutes. The column temperature was ramped to 225°F. The C_1 hydrocarbon was separated and the $>C_1$

hydrocarbons were eluted to the detector for quantifcation. A Mitac 486 Notebook computer was used to record and integrate the signal from the GC. A ±1% certified calibration gas (C_1-C_6 in N_2) was used to calibrate the GC before and after sample analysis to quantify the C_1 and >C_1 hydrocarbons. The beginning and end calibrations must agree within ±5% for the data to be acceptable. Duplicate analysis of selected samples were performed to insure replication within ±5%.

4.3 FUEL

A sample of the natural gas fired during this test program was collected and sent to Pacific Gas Technology for analysis. Analysis was performed by PGT in accordance with EPA Title 40 Section 60.45. The specific procedures are itemized in Table 4-1.

TABLE 4-1. FUEL ANALYSIS METHODS

Laboratory Test Procedures for Fuel Gases

Reference: EPA Title 40, Section 60.45

GASEOUS FUELS BY GAS-LIQUID CHROMATOGRAPHY:

Gas Analysis	ASTM D1945-81
Sulfur Analysis	CPA B16
Calculation of Gross Calorific Value	ASTM D3588-81
Component Wt-%, F-factor calculations	EPA 40:60.45

PGT
Pacific Gas Technology

2122 Q Street
Bakersfield, CA 93301
Telephone: 805 324-1317
Fax: 805 324-2746

Attention: Mr. Jim Steiner
Steiner Environmental, Inc
4930 Boylan Street
Bakersfield, CA 93308

Sampled: March 12 1998
Submitted: March 19 1998
Analyzed: March 20, 1998
Reported: March 23, 1998

Gas Analysis by Chromotography - ASTM D 3588-91

Company: Stewart & Stevensen
Location: GTB
Description:

Lab No.: 99027802
Steiner No.: 50356
Sample Type: Natural Gas

Component	Mole %	Weight %	G/MCF
Oxygen	ND	0.00	
Nitrogen	1.05	1.73	
Carbon Dioxide	0.76	1.96	
Hydrogen	ND	0.00	
Carbon Monoxide	ND	0.00	
Hydrogen Sulfide	ND	0.00	
Methane	94.06	88.61	
Ethane	3.64	6.43	
Propane	0.49	1.27	0.135
iso-Butane	ND	0.00	0.000
n-Butane	ND	0.00	0.000
iso-Pentane	ND	0.00	0.000
n-Pentane	ND	0.00	0.000
Hexanes Plus	ND	0.00	0.000
Totals	100.00	100.00	0.135

			Values Corrected for Compressibility
Specific Volume, ft3/lb		22.28	
Compressibility (Z) Factor		0.9978	
Specifc Gravity, Calculated		0.5879	0.5890
GROSS			
BTU/ft3	Dry	1026.8	1029.0
	Wet	1008.8	1011.0
BTU/lb	Dry	22880.3	22930.0
BTU/lb	Wet	22479.9	22528.7
NET			
BTU/ft3	Dry	925.6	927.7
	Wet	909.4	911.4
BTU/lb	Dry	20627.2	20672.0
BTU/lb	Wet	20266.2	20310.2

CHONS	Weight %
Carbon	73.050
Hydrogen	23.794
Oxygen	1.428
Nitrogen	1.727
Sulfur	0.000

F FACTOR @
68 deg F, dscf/MMBTU

F FACTOR @
60 deg F, dscf/MMBTU

Hydrogen Sulfide, ppm	Not Tested	*Method*	GC/FPD
Dew Point, deg F	Not Tested	*Method*	Bureau of Mines
Moisture, lbs H2O/MMCF	Not Tested	*Method*	Bureau of Mines

ND: None Detected *Tr Trace*

SECTION 5

QUALITY ASSURANCE

5.1 MANUAL SAMPLING EQUIPMENT

A detailed record of repair and maintenance to each sampling train is kept. Preventative maintenance to each system is performed periodically to avoid complete component breakdown during a field test.

A detailed record of sampling system calibrations is also kept. Calibration data for the sampling nozzles, pitot tubes, dry gas meters and orifice meters are available for review. The calibration data for the equipment used on this program may be found in the Appendix of the final report.

5.2 LAB ANALYSIS

All field samples are assigned a label and an ID number. This ID is also affixed to a chain-of-custody log and to the field data sheet to eliminate any chance of sample mixup.

Prior to analysis, all glassware is thoroughly cleaned (soap and water, tap water rinse, distilled water rinse, IPA rinse) to eliminate any contamination. The evaporating dishes used to evaporate the samples are treated the same as a sample (dried in an oven, desiccated and weighed repeatedly at 6-hour intervals until a constant weight is achieved).

The glassware used to measure volumes and make transfers and dilutions are all NIST Class A to insure accurate measurements. All weights are carried out on a Sartorius Research Model R160P electronic semi-micro balance supported by a marble table in a separate room from the main analytical laboratory. The balance is calibrated regularly against an NIST Class S-1 weight.

All reagents used in the field and in the laboratory are ACS reagent grade and blanks of these reagents are evaluated for every set of tests. Blanks are taken in the field from the squeeze bottles and not the original container. Records are kept on these blanks to insure consistent quality of the reagents. Prior to use, the IPA is also analyzed to insure no peroxides are present which could lead to high SO_3 and low SO_2 values.

A quality control program consisting of duplicate analysis (to measure precision), spikes (to measure recovery efficiency) or analysis of blind standards (to measure accuracy) is implemented for each test program. Table 5-1 summarizes the results of the QA/QC checks.

5.3 QUALITY ASSURANCE/QUALITY CONTROL FOR CONTINUOUS MONITORS

The results of the checks performed on the Steiner Environmental CEMS during the test program are presented in the Appendix of the final report. The interference tests performed on the NO_X, CO, CO_2 and O_2 analyzers using EPA Method 20 will also be included.

5.4 QUALITY ASSURANCE OF ROC ANALYSIS

Each sample container is purged in the field with sample prior to the actual tests. A certified gas is used to calibrate the gas chromatograph used to measure the hydrocarbons.

The calibration certificate for the gas used is included in the Appendix of the final report.

Duplicate analysis of some samples was conducted.

TABLE 5-1. ROC QA/QC CHECKS

Test Number	Test Parameter	Duplicate (%)	Recovery (%)
1	Filterable Sulfate	104.0	
4	Filterable Sulfate		100.0
	EPA SO_2 Lot 0593-2xxx		100.0
1	Condensible Sulfate	100.0	
3	Condensible Sulfate		100.0
1	SO_2	100.0	
3	SO_2		100.0
3 (50%)	$>C_1$ HC	102.2	
1 (100%)	$>C_1$ HC	99.9	
1	NH_3	99.2	
3	NH_3		102.1
	RICCA 50 ppm Standard		103.8 Before 97.0 After